BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Cases 14-E-0493 and 14-G-0494

In the Matter Of

Orange & Rockland Utilities, Inc.

ELECTRIC AND GAS RATES

March 2015

Prepared Redacted Exhibits of:

Staff Advanced Metering
Infrastructure (AMI) Panel

Jason P. Pause
Power System Operations Specialist 4
Office of Electric, Gas, and Water

Martin Insogna
Utility Consumer Program Specialist 5
Office of Consumer Services

Johanna Miller
Utility Engineer 2
Office of Electric, Gas, and Water

Robert Cully
Utility Engineer 1
Office of Markets and Innovation

State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

LIST OF EXHIBITS

Exhibit SAMI-1

Relied Upon O&R Responses to Information Requests

Table of Contents

---

[1] The attachments to this IR response are benefit cost analyses for the AMI rollout and are available as separate MS Excel files.
[2] The attachment to this IR response is a detail of the costs and benefits of the AMI rollout and is available as a separate MS Excel file.
[3] The attachment to this IR response is a detail of the costs of the AMI rollout and is available as a separate MS Excel file.
[4] The attachments to this IR response are cost estimates, meter inventory, and updated benefit cost analysis and are available as separate MS Excel files.
[5] The attachment to this IR response is a benefit cost analysis of AMI in the Pomona area and is available as a separate MS Excel file.

Exhibit__(SAMI-1)
Pages 1 through 9 of 83 have been redacted.

Company Name: O and R Utilities, Inc.
Case Description: Orange and Rockland Electric and Gas Filing 2014
Case: 14-E-0493; 14-G-0494

Response to DPS Interrogatories – Set DPS-14
Date of Response: 02/11/2015
Responding Witness:

Question No. : 309 Supp

Subject: AMI Panel Initial Testimony -

1. Provide a copy of the United States Department of Energy study referenced on page 9, lines 16-21, of the AMI Panel's initial testimony.

2. Provide a copy of the independent assessment of AMI suppliers performed for the Company by Accenture, as described in the AMI Panel's initial testimony on page 17, lines 8-11.

3. Does the Company have plans for how data collected by AMI-enabled meters installed at customer locations will be distributed to such customers? If so, explain the Company's plan to distribute such data to customers.

4. Provide a detailed Benefit Cost Analysis demonstrating the cost-effectiveness of the Company's AMI rollout plans. Include and separately identify the benefits (e.g. deferred carrying costs, avoided energy costs, avoided capacity costs, and environmental externalities). Perform the analysis on a Net Present Value basis over the course of the entire useful life of all assets. Provide the analysis in Microsoft Excel format with all cells unlocked, all formulae intact, and all linked files included.

5. Will the Company's AMI rollout plans result in stranded costs? If so, determine the magnitude of the stranded costs caused by the AMI rollout and include such costs in the benefit cost analysis described above.

6. Does the Company plan to remotely connect or disconnect customers using AMI? If so, is the Company planning to enact protections for customers to ensure affected customers are treated fairly and equitably? Describe any proposed customer protections.

7. Describe how the Company developed the $15 monthly manual meter reading fee, as described in the AMI Panel initial testimony on page 24, lines 17-19.

8. Describe how the Company developed the one-time meter change fees of $225.00, $ 135.00, and $100.00 for combined gas and electric customers, electric-only customers, and gas-only customers, respectively, as described in the AMI Panel initial testimony on page 25, lines 4-10.

9. Explain why a field visit is required to reprogram a gas AMI meter, but is not required for an electric AMI meter.

10. Describe how the Company developed the one-time gas AMI activation fee of $55.00, as described in the AMI Panel initial testimony on page 24, lines 13-16.

Response

4. The Company supplements its previous response to DPS14-309, subpart 4, by providing the requested analysis on a Net Present Value basis over the course of the entire useful life of all assets. Please see attachment DPS14-309 Att-3.

Exhibit__(SAMI-1)
Pages 12 through 26 of 83 have been redacted.

Company Name: O and R Utilities, Inc.
Case Description: Orange and Rockland Electric and Gas Filing 2014
Case: 14-E-0493; 14-G-0494

Response to DPS Interrogatories – Set DPS-30
Date of Response: 02/26/2015
Responding Witness: AMI Panel

Question No. : 450

Subject: AMI Panel Testimony

1. Provide an O&R service territory map identifying both where AMR is currently deployed and where the Company proposes to deploy AMI.

2. The Company is proposing to install 116,000 electric AMI meters. Provide a breakdown of the AMI meters by Residential, Commercial, and Industrial customers, respectively.

3. Provide the total number of customers with AMR at this time. Provide a breakdown of those AMR customers by Residential, Commercial & Industrial.

4. Given the proposed cost savings associated with the implementation of AMI, provide an explanation as to why customer rates should not be reduced with the implementation/deployment of AMI. Additionally, explain why the projected O&M savings should not be used to offset other proposed O&M increases such as labor and additional position in the electric operations department.

5. During the January 21, 2015 meeting between Staff and the Company, O&R stated that the AMI meters have a 20 year life expectancy. Provide supporting documentation for that statement.

6. Provide an explanation and supporting documentation showing what the Company has done to ensure proposed cost estimates will not be surpassed in the deployment of AMI.

7. Has the Company done any cost comparisons of other AMI deployments in other states? If so, provide and explain the cost comparisons. This should include all aspects of AMI deployment, including but not limited to: meter installation, communications system, and backhaul data collection/analysis systems.

8. O&R identified a savings of $86.8 million over 20 years associated with the AMI deployment proposal. Provide an explanation showing why the 20 year timeframe for the savings was selected. What would the cost savings be over 10 years instead of 20 years?

Response

1. Please see map and explanation.

- AMR is deployed in various locations of the O&R Electric Only Areas and in various locations of O&R Electric and Gas Areas.
- Phase 1 of the Company's AMI proposal is to install AMI in the Rockland County (ENY) portion of the Company's service territory.

2 & 3.

Please see the following tables detailing the breakdown of all customers by residential, commercial and industrial including the number of AMR customers as of January 2015. All customers identified in the ENY division for both electric and gas would receive AMI metering as part of our Phase One proposal.

DIVISION	ELECTRIC	TOTAL MTRS	AMR
ENY	RESIDENTIAL	102,755	34,256
	COMMERCIAL	14,525	597
	INDUSTRIAL	93	-

	EAST TOTAL	**117,373**	**34,853**
CNY	RESIDENTIAL	50,498	30,990
	COMMERCIAL	8,299	837
	INDUSTRIAL	42	-
	CENTRAL TOTAL	**58,839**	**31,827**
WNY	RESIDENTIAL	48,195	24,991
	COMMERCIAL	6,917	648
	INDUSTRIAL	33	-
	WESTERN TOTAL	**55,145**	**25,639**
CONSOLIDATED TOTAL		**231,357**	**92,319**

DIVISION	**GAS**	**TOTAL MTRS**	**AMR**
ENY	RESIDENTIAL	84,027	20,151
	COMMERCIAL	8,469	1,880
	INDUSTRIAL	56	9
	EAST TOTAL	**92,552**	**22,040**
CNY	RESIDENTIAL	19,726	10,913
	COMMERCIAL	1,967	1,138
	INDUSTRIAL	11	1
	CENTRAL TOTAL	**21,704**	**12,052**
WNY	RESIDENTIAL	18,899	8,532
	COMMERCIAL	2,554	1,245
	INDUSTRIAL	34	9
	WESTERN TOTAL	**21,487**	**9,786**
CONSOLIDATED TOTAL		**135,743**	**43,878**

4.

The AMI project will not realize O&M savings in the first year of implementation. As shown in the Company's reply to DPS-14-309, savings will be realized in the following year subsequent to its implementation of the communication system, installation of meters and integration of the AMI system with other Company systems.

The Company believes that these savings should be used to the benefit of its customers. In recognition of the fact the savings will be realized on a phased in basis, the Company proposes to track and defer any savings for use in reducing future rates to customers. Additionally, in the event that a multi-year agreement may be negotiated, the Company is open to discussing the timing and method for applying these savings for the benefit of customers.

5.

Please see the attached engineering reports on life expectancies of electric meters and gas modules. **These reports should be considered as confidential information**.

The electric meter results are summarized in the table below.

Percept Technology Lab Test Results		
Meter Form	**Years of Service(@ 100% Duty Cycle)**	**Hours of Service(@ 100% Duty Cycle)**
	50°C(122°F)	**50°C(122°F)**
1s RD	**23.94**	209,684
2s	**27.73**	242,923
2s RD	**24.02**	210,419

Electric: Please see CONFIDENTIAL attachments DPS30-450 Att-1, DPS30-450 Att-2 and DPS30-450 Att-3.

Gas: Please see CONFIDENTIAL attachment DPS30-450 Att-4.

6.

As set forth in the Company's reply to DPS-14-309, the Company has been diligent in estimating the costs for Phase One of its proposed AMI project. The details of that estimate and supporting documentation were presented to Staff on February 11, 2015. If the Commission approves the Company's proposed AMI project, the Company will proceed with the project as planned. Doing so will involve issuing requests for proposal for various components of the implementation and, subsequently, negotiating purchase orders. The Company believes that this process should allow for actual costs to track cost estimates. Please see attachment DPS30-450 Att-5.

7.

Yes, the Company has conducted benchmarking along with Con Edison in reviewing costs of other AMI deployments. Each of these cases, provide some specific level of details for all of the cost components. However, each case is different in scope due to their particular service territory and product offerings being proposed in their respective proposals. Please see the following table:

Utility Benchmarking

($ Millions)

Category		BGE	Center Point	Dominion	Duke	Duke-Ind	PG&E	SCE	SDG&E
Meter Costs			$ 330.70		$ 130.30	$ 161.80	$ 1,537.00		
	Hardware	$ 150.00		$ 426.80				$ 726.10	
	Installation			$ 71.40				$ 296.60	
Comm. Costs			$ 81.30		$ 142.87				
	Hardware								
	Software								
IT Costs			$ 80.12	$ 11.42	$ 66.66	$ 9.80	$ 493.00	$ 250.80	
	Hardware								
	Software								
Total Costs		**$ 421.80**	**$ 496.80**	**$ 550.40**	**$ 339.80**	**$ 191.00**	**$ 2,336.00**	**$ 1,645.40**	**$ 572.00**

8.

The 20-year life for the project was selected to reflect the life span of most of the equipment required to be deployed in an AMI system. Where a component does not have a 20-year life span the cost/benefit analysis includes the cost to replace/upgrade that equipment on the appropriate basis (e.g., five years for servers).

The savings at ten years would be $28.8 million.

Exhibit__(SAMI-1)
Pages 32 through 64 of 83 have been redacted.

Company Name: O and R Utilities, Inc.
Case Description: Orange and Rockland Electric and Gas Filing 2014
Case: 14-E-0493; 14-G-0494

Response to DPS Interrogatories – Set DPS-35
Date of Response: 03/02/2015
Responding Witness: AMI Panel

Question No. : 485

Subject: AMI Deployment

1. Provide a detailed explanation and breakdown of the stranded costs associated with replacing both existing electro-mechanical electric meters with useful life left and the existing AMR meters already installed that are proposed to be replaced by new AMI meters. Provide response and associated data on a meter-by-meter basis and in total for each scenario.

2. For each of the following Interface efforts identified in the Company's response to DPS-262 Attachment 3, provide a detailed description of the existing system and how the AMI data will actually interface and be used with the existing system. Provide an existing system interface diagram as well as a newly proposed system interface diagram incorporating AMI. Provide supporting documentation on how the cost estimates provided for each of these interface efforts were developed.
   a. OMS Interface
   b. CIMS Interface
   c. GEMS Interface
   d. Electric Distribution Interface
   e. MDMS Interface

3. Provide examples in the Company's AMI implementation plan where O&R implemented lessons learned from other utilities where AMI was deployed elsewhere in the US. Identify the utility, location of deployment, and number of AMI meters installed in each example provided.

4. Provide examples and/or comparisons of costing data obtained from other utilities where AMI was deployed elsewhere in the US. Identify the utility, location of deployment, and number of AMI meters installed in each example provided. Where possible, provide data broken down into the following categories:
   a. Meter Installation
   b. Communications Infrastructure
   c. Data Collection / Interface / Backhaul Systems

5. Provide a detailed explanation of whether or not O&R performed any type of alternative analysis to AMI deployments that would provide similar benefits in the following areas to its customers.
   a. Energy Efficiency

b. Demand Response
c. Outage Detection & Restoration
d. System Engineering & Planning

6. Are there any examples where electric utilities implemented large scale deployments of AMI elsewhere in the US and the utility passed/passes savings back to customers in the form of rate reductions? If so, explain.

Response

1. The estimated depreciation cost of meters to be replaced shown in the Company's cost/benefit analysis (see DPS-14-309) was developed by dividing the undepreciated net book cost for all electro-mechanical and solid state meters, as of 12/31/2013, by the total number of meters in each category to arrive at an un-depreciated cost per meter for each category. The undepreciated cost per meter was then multiplied by the number of meters to be replaced (minus any meters to be restocked) in each category. In reviewing the development of these costs, the Company found that the undepreciated costs shown in DPS-14-309 were incorrect due to the transposition of two numbers in the initial undepreciated cost per meter calculation and use of an incorrect multiplier in the original cost/benefit analysis. These errors have been corrected and a revised cost/benefit analysis is provided in attachment DPS35-485 Att-1. The corrected undepreciated cost is shown in cells F-84, F-85, G-84 and G-85 of the updated cost/benefit analysis attached below.
   Also provided are the inventory (DPS35-485 Att-3) and depreciation (DPS35-485 Att-2) reports used in the development of the attached updated benefit/cost analysis. As detailed in the attached inventory report (see tab labeled 1980-2014, Cell AS181), the total number of electro-mechanical meters to be replaced in this project is 71,341. The report also identifies the number of solid state meters in the project service area as 44,448 meters (see tab labeled 1980-2014, Cell AT179). Additionally, the report identifies all AMR meters in service which is a subset of the total solid state meters, totaling 32,483 (see tab labeled 1980-2014, Cell AU179) that will be replaced by AMI meters. Of those AMR meters, 11,704 will be re-stocked for use in other areas. The attached depreciation report details the associated net costs per meter for electromechanical meters and solid state meters (see Cells H15 & I16). In addition, the Company provides an updated financial analysis (DPS35-485 Att-4) that reflects the corrected un-depreciated meter costs from the attached cost/benefit analysis.

2. OMS – Currently, outage information is received from customers, whether by a customer service representative, VRU application or an on-line web application, and is entered into CIMS and transmitted to OMS by CIMS. AMI will provide an additional and more direct path that will not require customer action. That is, outage information from the customer's meter will alert OMS of an outage. AMI meters will also provide a restoration message to OMS when power is restored. Additionally, AMI allows for interrogation (pinging) of meters on a distribution circuit or a particular customer location to see if power has been restored. Please see attachment DPS35-485 Att-5.

CIMS – The current process of entering customer usage into the Company's billing system occurs in several ways. One path is that CIMS sends a reading request file to our Itron Meter Reading System, which is downloaded into either a handheld device or a mobile collector device. After the readings are obtained, an upload file is generated by the Itron system and sent back to CIMS with the necessary consumption data for the production of a customer bill. In cases where meter information is used for load research purposes, a separate file is uploaded from the Itron system into the MV-90 system and then transmitted to the Load Profile Data System ("LPDS") for Rate Engineering use. A second billing path, in cases where customers are on mandatory hourly pricing, is through telephone transmittal (landline or cellular) of interval usage data directly to MV 90. The data is then transmitted from MV 90 to LPDS, then into Load Star Billing where billing determinants are applied and passed into CIMS to generate the customer's bill.
With the deployment of AMI, interval metering data required for billing could be passed directly from the AMI head-end system into MV-90 daily. For customers requiring only monthly consumption data for billing, a file will be transmitted to CIMS from the AMI head-end system on the normal schedule read day. Also, part of the CIMS integration will include the ability to remotely obtain a reading from the customer's meter, perform connects and disconnects at an appropriately equipped meter, view 60 days of customer recorded consumption, and verify voltage levels at the customer's meter.
In addition, integration of a Meter Data Management System ("MDMS") will include a path from CIMS to MDMS for the update of any changes involving metering data, customer data or rate changes that may have occurred. Please see attachment DPS35-485 Att-6.

GEMS - The current process of tracking meter assets will change very little with the introduction of AMI. GEMS will need additional manufacturer codes and meter type codes added into the system. The existing and future process tracks the receipt of incoming meters, meter installs at customer premises, meter retirements, and for in stock meters, the store room location and in-transit status between storerooms. Through monthly batch processes, meter first install information and retirement information is passed to the Cost and Project Accounting Department. Also, additional batch files are exchanged between CIMS and GEMS to provide CIMS with meter information related to meter manufacturer and meter type in service at the customer's premise. Conversely, CIMS provides GEMS with changes that may occur for meters installed, exchanged or removed including customer premise information. Please see attachment DPS35-485 Att-7.

Electric Distribution Interface – The current process stores interval metering data, collected through our current metering process, in LPDS. When requested by Electric Engineering a batch job is initiated to extract the data and transmit it to the Distributed Engineering Workstation ("DEW") system. Once the interface is completed with MDMS, data for DEW would be extracted from that system. Please see attachment DPS35-485 Att-8.

<u>MDMS</u> - Currently interval metering usage data from LPDS is transmitted to MDMS for storage purposes. Upon implementation of AMI, interval usage data, as well as KW, KWhrs, KVar and Voltage data will be transmitted from the AMI head-end system to MDMS. An additional batch file will be extracted from CIMS to update MDMS on any changes to meter identification data, customer data or rate changes that may have occurred. Capturing these additional data elements will enable the Company to provide additional services/programs such as customer usage data presentment, Energy Efficiency and Demand Response programs; and to optimize the value of its electric distribution system. Also, such data elements will be key to stimulating markets and enabling new revenue models that will proceed from the state's REV initiative. Please see attachment DPS35-485 Att-9.

The costs associated with these integration points is detailed in the attached ENY AMI Worksheet under tab labeled "integration." Supporting documentation from the various business organization and manufacturers estimates are summarized in attachment DPS35-485 Att-10.

3. In anticipation of the approval of its Phase One AMI proposal, the Company is developing a detailed AMI implementation plan that will include lessons learned from other utilities. Among the lessons which will be considered are those in attachment DPS35-485 Att-11.

4. The table provided below shows comparative meter deployment costing data obtained to date by O&R and Con Edison.

Utility Benchmarking

($ Millions)

Category		BGE	Center Point	Dominion	Duke	Duke-Ind	PG&E	SCE	SDG&E
Meter Costs			$ 330.70		$ 130.30	$ 161.80	$ 1,537.00		
	Hardware	$ 150.00		$ 426.80				$ 726.10	
	Installation			$ 71.40				$ 296.60	
Comm. Costs			$ 81.30		$ 142.87				
	Hardware								
	Software								
IT Costs			$ 80.12	$ 11.42	$ 66.66	$ 9.80	$ 493.00	$ 250.80	
	Hardware								
	Software								
Total Costs		**$ 421.80**	**$ 496.80**	**$ 550.40**	**$ 339.80**	**$ 191.00**	**$ 2,336.00**	**$ 1,645.40**	**$ 572.00**
				(Millions)					
# of Meters		**1.76**	**2.13**	**2.51**	**0.97**	**0.82**	**9.20**	**5.30**	**2.30**
	Electric	**1.10**	**2.13**	**2.51**	**0.97**	**0.82**	**5.00**	**5.30**	**1.40**
	Gas	**0.66**					**4.20**		**0.90**
Avg, Cost per Meter		**$ 257.44**	**$ 233.17**	**$ 219.30**	**$ 350.34**	**$ 232.93**	**$ 253.91**	**$ 310.45**	**$ 248.70**

5. O&R did not perform an alternative analysis to AMI deployments because the Company is not aware of any alternatives that would provide similar benefits in all of the noted areas. Specifically:

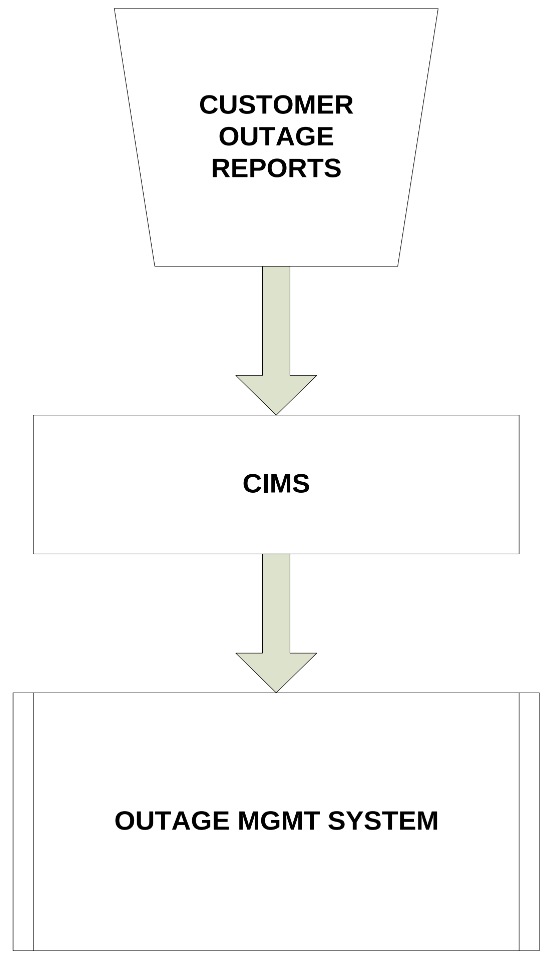
   a & b.) In researching other utilities' AMI activities it became apparent that providing a single solution to the customer is an efficient way to deliver energy efficiency and demand response products. Providing a single solution to the customer eliminates the need for multiple devices and strategies and simplifies the customer's ability to control their energy use in addition to the grid integration of distributed energy resources.

   c.) The Company is not aware of any other alternative that provides and transmits directly to Company systems outage information at the premise level.

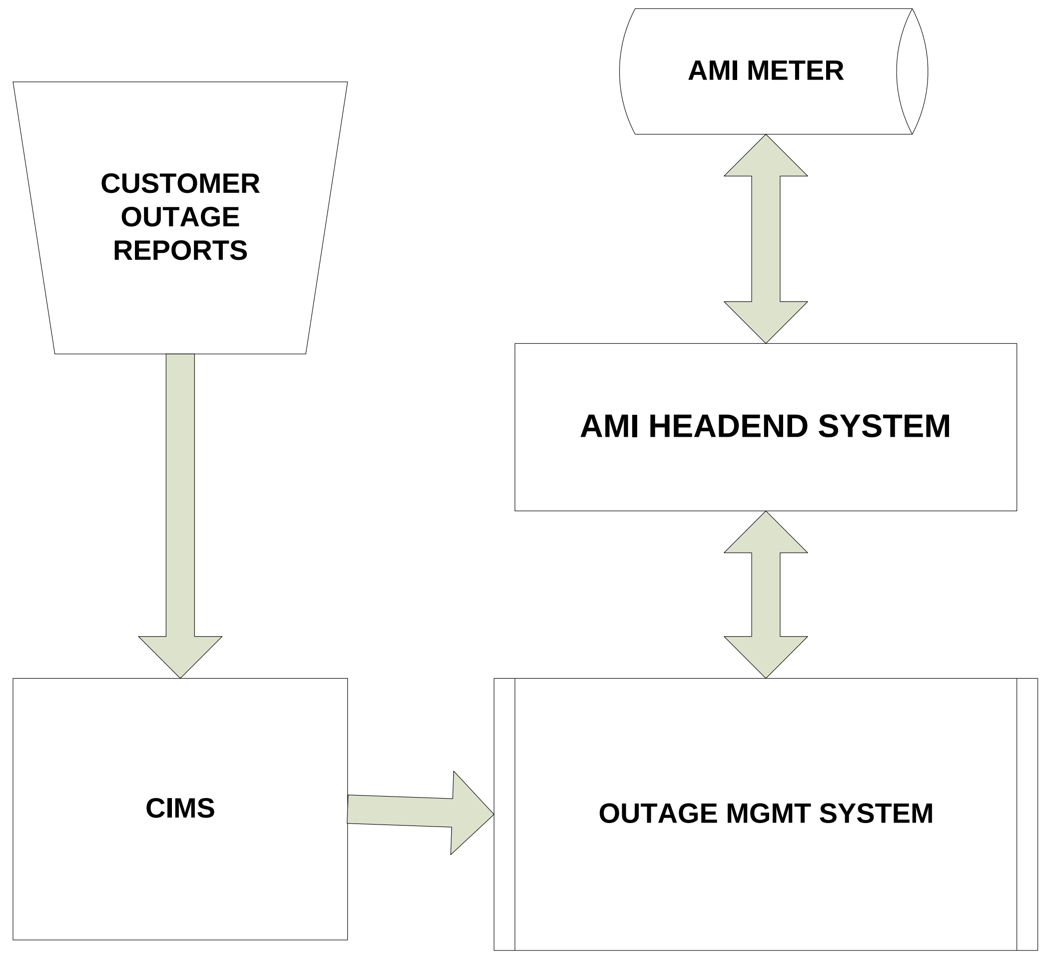
   d.) System engineering and planning includes the use of assumptions regarding customer load patterns. AMI will provide actual and granular data that can be used to optimize system efficiency. The Company is not aware of an alternative that allows for the ongoing communication and collection of such data into Company systems in an efficient manner.

6. The Company is not aware of any utilities that have implemented large scale AMI deployments in the United States and have passed savings back to customers in the form of rate reductions.

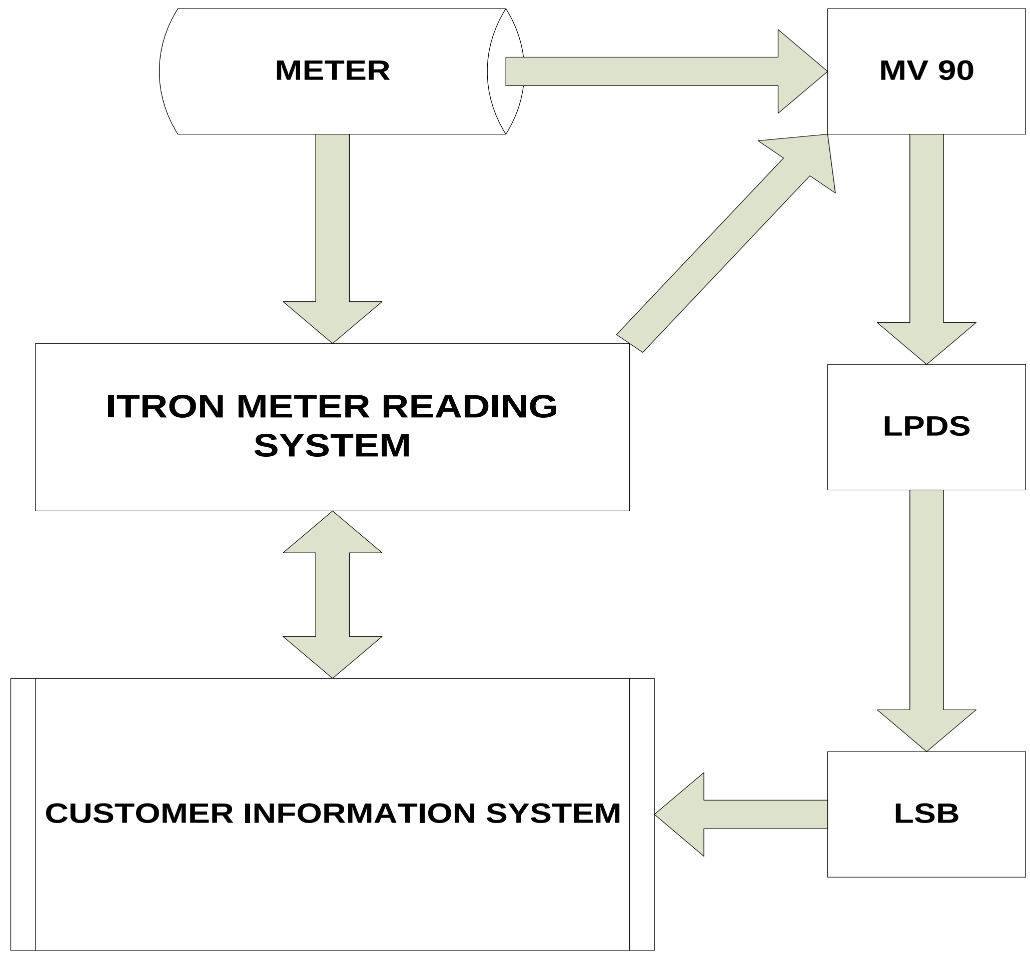
Existing OMS Process



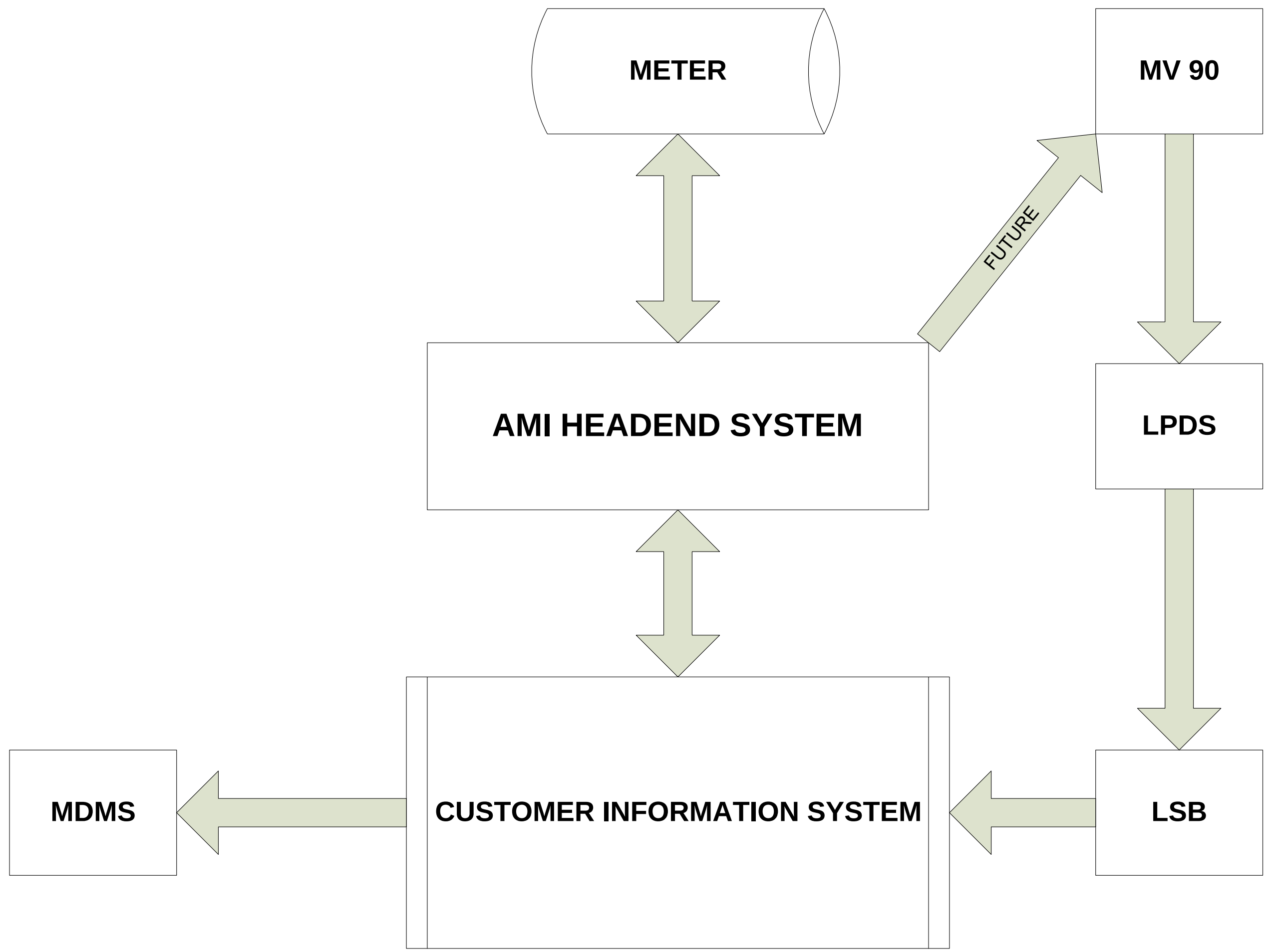
New OMS Process



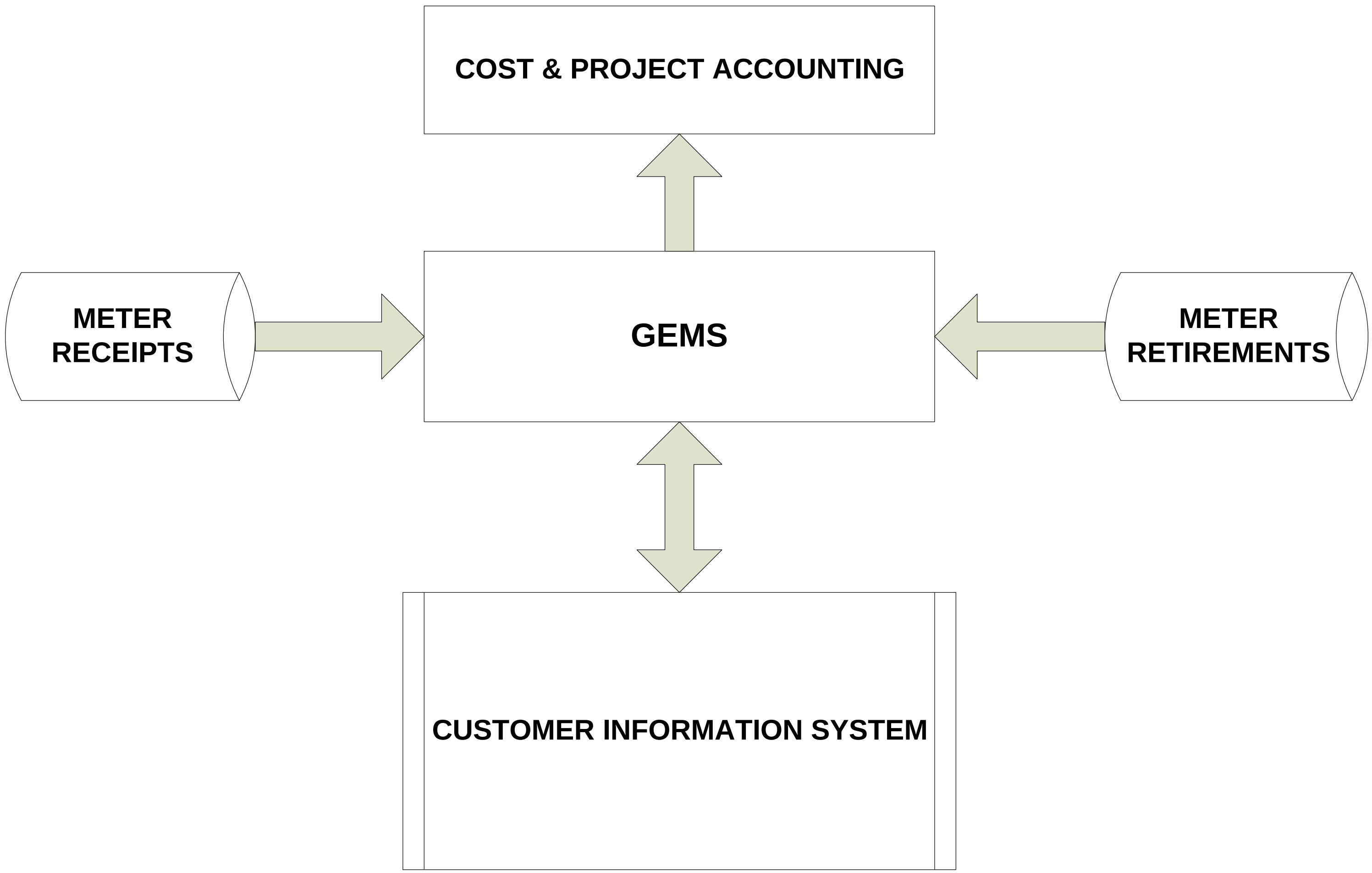
Existing CIMS Process



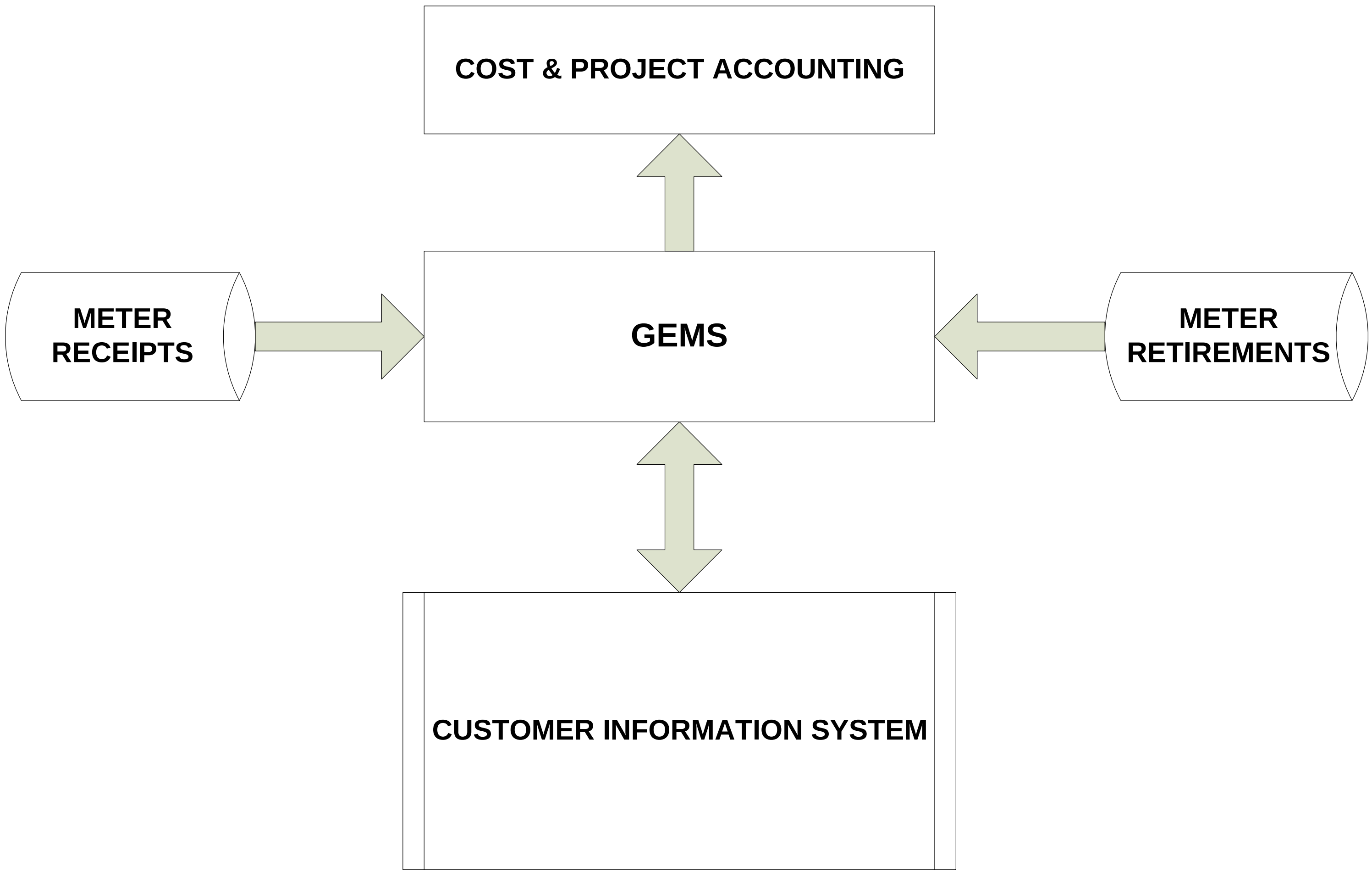
New CIMS Process



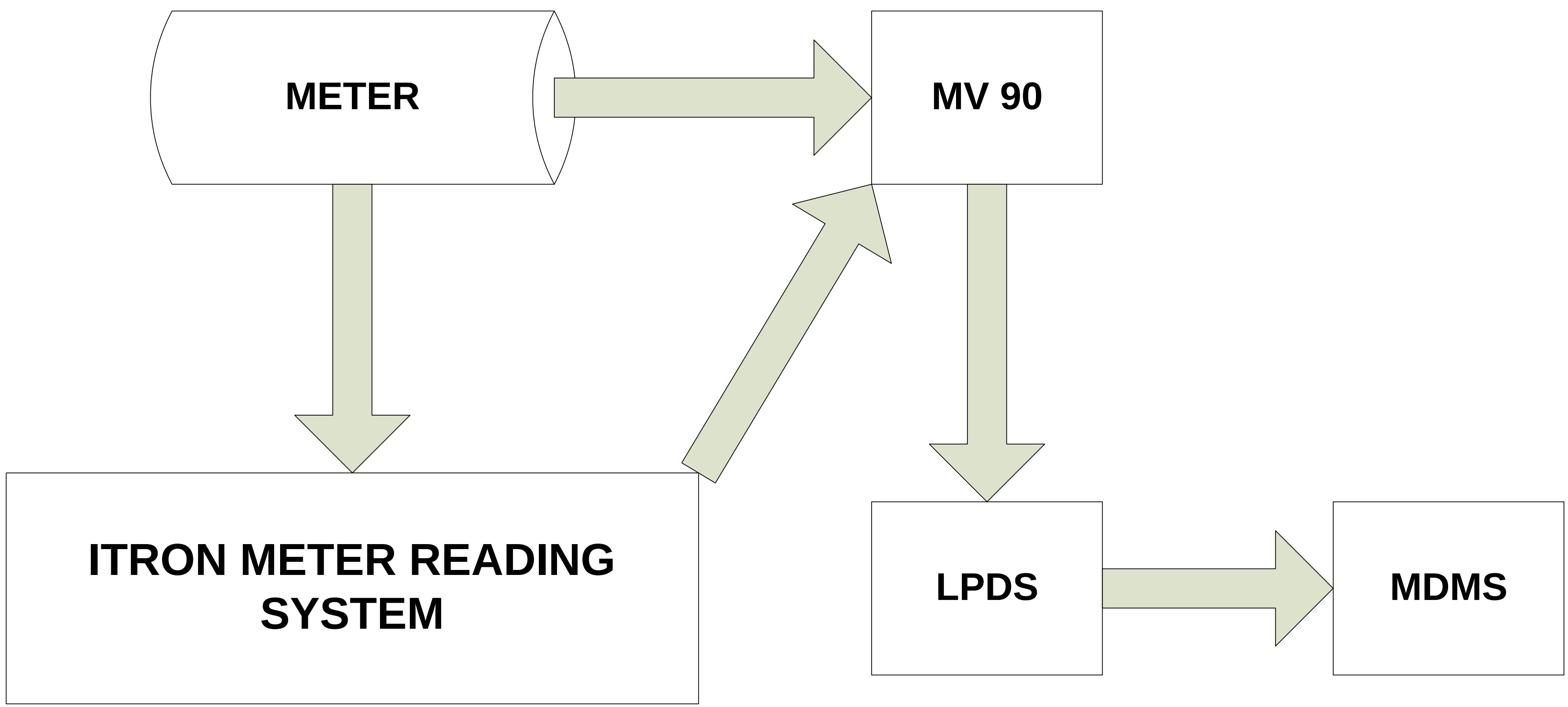
GEMS Process



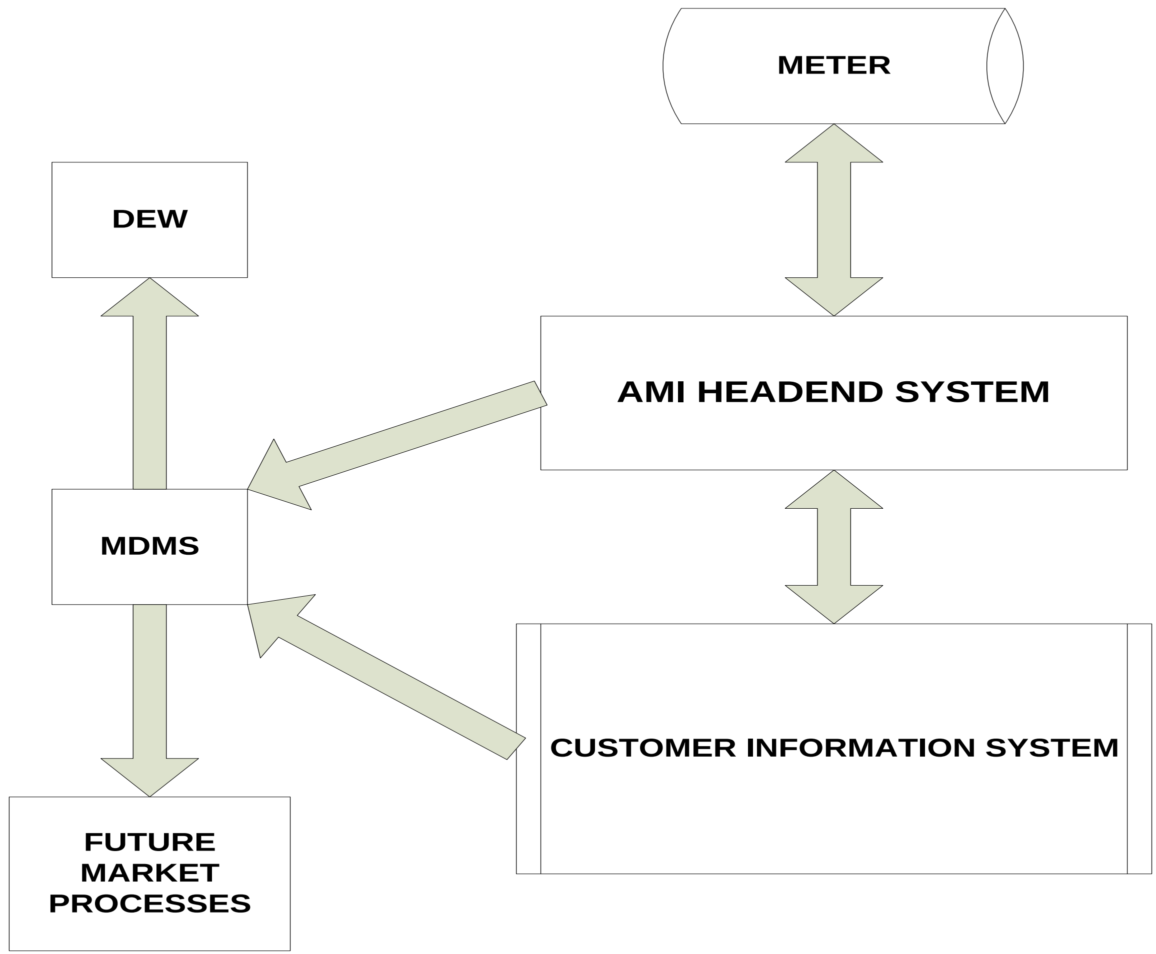
GEMS Process



Existing MDMS Process



New MDMS Process



<u>CIMS</u>

<u>Interface: CIMS to RNI for Remote Connect / Disconnect:</u>

Estimate of $228,000 based on contractor rate of $1,900 per day for 120 days.

<u>Interface: CIMS to RNI for On Demand Meter Reads:</u>

Estimate of $228,000 based on contractor rate of $1,900 per day for 120 days.

<u>Interface: CIMS to RNI for Daily Read Interface between Head End and CIS :</u>

Estimate of $37,400 based on 320 hours of internal resource at $117 per hour. $117 per hour is based on annual salary of $130,000 plus 80% for overheads.

<u>Interface: CIMS to RNI for Interface required to report meter exchange information at site to RNI:</u>

Estimate of $114,000 based on contractor rate of $1,900 per day for 60 days.

<u>GEMS</u>

In response to the Asset Management interface listed in this spreadsheet, to build an interface between GEMS and SENSUS for meter attribute information (such as MAC address IDs and other meter functionality), the estimate is 2 months for a contractor = $26,000.

The expectation is that SENSUS would send a file of meter attribute information using RDX file transfer process, the information gets loaded to a new GEMS database table, and a cross reference process built with the GEMS VSAM master file. Alternatively, append fields to the GEMS VSAM master file and modify all programs that use the GEMS VSAM master file to account for the new fields.

In addition, the contractor would be utilized for:

- Increasing the size of the manufacturer field in GEMS. Requires VSAM file changes and database table changes. Several programs that use the manufacturer field need to be modified to accommodate the new field size.
- Add logic to bypass first install process for these meters associated with the AMI project
- Testing the meter receive interface between GEMS and Power Solve

<u>MDMS</u>

$250,000 Sensus estimate provided in consultation with Con Edison IR personnel.

<u>OMS</u>

OMS will require interfaces to facilitate the integration of outage data from Sensus. OMS will use the Outage Detection web service for these communications. Sensus will provide OMS with meter outage data. OMS will process this data and incorporate it into its predictive logic business rules. In addition to receiving outage data, OMS will also be able to use the same interface to receive outage data on meters that are pinged within the Sensus application. This data will be used to understand if we still have nested outages as we begin our restoration processes. The cost estimate for both integration points is

$112K. This estimate is based on 1 months of requirements, 3 months of developments and 3 months of testing at a rate of $100/ hour.

DEW

$100,00 provided by Electric Engineering business owners.

AMI Benchmarking Summary

Company	Meters Installed (2014)	Target Meters Installed		Lessons Learned
PECO	1.95 million	2 million (1.5M Electric, .5M Gas)		• Change management is critical – start early • Consider using odor certified techs for gas meter installations • Specify routes to installation vendors to improve efficiency – don't rely on them to design
ComEd	740,000	4.2 million		• Detailed business case helped explain and communicate benefits/costs to internal and external stakeholders • High rise buildings present unique communication challenges • Change management and communication critical – with customers, employees, other stakeholders • Communication efforts helped keep opt out rate very low • AMI requires significant team to implement and rethought organizational structures to sustain
CenterPoint	2.3 million	2.3 million		• Inventory control will be challenging with smart meters due to software updates and versions. • AMI creates large amounts of data – filtering should be done as close to the meter as possible. • It is well worth the investment in meters with a large enough capacitor to filter out false outage alerts from momentary disruptions. • Establishing an in-house meter farm will allow for testing of system technology variations when implementing changes. • The communications network will become a critical asset and needs robust monitoring. • Engage with community leaders and organizations early to help educate the public about smart meters.
Misc.				General lessons learned from industry expert: • Must organize and staff project correctly – during and after project • Business process designs/changes must be considered early in project • Change management is critical success factor – need to communicate to stakeholders • Early AMI adopters have achieved value and are planning replacements/upgrades to their systems • Due diligence on AMI technology vendors is critical • Focus on core elements of project first – process designs, MDMS, implementation planning and execution

Company Name: O and R Utilities, Inc.
Case Description: Orange and Rockland Electric and Gas Filing 2014
Case: 14-E-0493; 14-G-0494

Response to DPS Interrogatories – Set DPS-50
Date of Response: March 18, 2015
Responding Witness: AMI Panel

Question No. : 549

Subject: AMI Deployment -

1. Provide a detailed explanation on the Company's position if AMI were only deployed in the Pomona area as part of a pilot program instead of the full Rockland County deployment as proposed in testimony. Specifically address the impact of a limited deployment of AMI in the Pomona area on the implementation costs.

2. Referring to the comparison of limited AMI deployment in the Pomona area versus full deployment in Rockland County identified in question #1, address the potential for flexibility and scalability in the communications network and meter data management system. If either or both of these components are not flexible or scalable, explain why not, and identify any limitations on right-sizing or expansion of such systems that are contractual, as opposed to technical limitations. Also, explain how such components will be applied to future expansion of AMI.

RESPONSE:

1. Limiting the Company's deployment of AMI deployment to the Pomona area is inherently inefficient, because the costs required to purchase, install and integrate new meter data and communication systems for such a limited deployment are essentially the same as those for a full deployment. Limiting AMI deployment to the Pomona area will greatly reduce the benefits of AMI deployment. In addition, a full Rockland County deployment allows for the establishment of a more effective and efficient communications network.

   Attached (DPS50-549 Att-1) is a **CONFIDENTIAL**, preliminary cost/benefit analysis for an AMI implementation limited to the Pomona area. The Company prepared this analysis on an expedited basis in response to a Staff request and it is by nature preliminary. The Company reserves the right to revise this analysis based on the vetting of its assumptions. However, this preliminary analysis provides a usable order of magnitude for comparison with the cost/benefit analysis provided in the Company's response to DPS-35-485.

In essence, although the overall capital expense of an AMI deployment limited to the Pomona area would be less than that of the proposed total implementation, the benefits to all customers are significantly reduced. As a result, the limited deployment would result in customer rate increases over the 20-year horizon, while the proposed Phase One implementation results in customer rate decreases over that period. This is because system, integration and ongoing O&M components are required for either a limited deployment or a complete county-wide deployment. In preparing the attached, the capital costs applied reflect the system and integration costs referenced above, as well as, replacement of only the 7,434 meters currently located in the Pomona area. Recurring O&M costs are detailed, and customer benefits are scaled to correspond with the ratio of the Pomona meter replacements to the meter replacements in the proposed Phase One project. Of note is that the limited Pomona deployment would result in a <u>net cost to customers</u> of approximately $11,000,000 over the 20-year life of the meters vs. an $ 82,200,000 benefit to customers that would result from the proposed complete deployment. The impact to customers of the limited deployment, absent strategic benefits that are not included in the analysis, would be bill increases of approximately $941,000 compared to bill decreases of $1,756,000 if the complete deployment is undertaken.

AMI technology is proven and currently serves over 40% of American households. Given that, the attached cost/benefit analysis and customer benefits to be achieved, the Company strongly endorses a full Phase One implementation as the first step in a broader deployment of this technology throughout its service territory. Also, the Company respectfully submits that although limited deployment will enable market development in that small part of the Company's service territory, it will also build delay into such market development in the rest of O&R's service territory as a result of less than optimal utilization of this proven technology.

2. The meter data and communication systems, and integration of those systems into other Company systems, including the Outage Management System (OMS) and the Customer Information Management System (CIMS), are not scalable. Stated another way, the resources required to purchase, install and integrate these new systems is essentially independent of the number of meters deployed. The system and associated costs would be essentially the same, whether 7,000 meters or 200,000 meters are deployed.

   With regard to the communications network, the number of towers necessary to receive and transmit data to the installed meters could be scaled down if the area of deployment were limited to Pomona, but this approach is inefficient. For example, under the limited deployment scenario, towers installed to communicate solely with meters in Pomona would be underutilized, as their reach would extend beyond the seams of that area of the service territory. Establishing the communications network in a well-planned, comprehensive manner is the most effective and efficient way to create a robust, reliable communications network.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2010-00051
(Phase II)

June 17, 2013

CENTRAL MAINE POWER COMPANY
Annual Price Change Pursuant to the Alternate Rate Plan

ORDER INITIATING MANAGEMENT AUDIT

WELCH, Chairman[1]; LITTELL and VANNOY, Commissioners

I. SUMMARY

By this Order, we initiate a management audit of Central Maine Power Company's (CMP or Company) management of its Advanced Metering Infrastructure (AMI) project. This audit is initiated pursuant to 35-A M.R.S. § 113 and is intended to address whether CMP's projections of costs and savings upon which approval of the AMI project in January of 2010 were premised were reasonable and prudent; whether CMP's management of the AMI Project was reasonable and prudent and conducted in a manner that was designed to meet budgetary (costs and savings) objectives; and finally, whether CMP reasonably and prudently managed the AMI project[2] and related systems to timely implement the supply side programs, the benefits of which were envisioned by the Commission at the time it authorized the project.

II. BACKGROUND

In CMP's most recently completed rate case proceeding, the Company proposed to implement AMI on a company-wide basis. Given the complexity of the project and the rapid changes occurring in AMI standards, the parties to the Stipulation that resolved CMP's rate case agreed that a decision on the Company's AMI proposal, as well as a further examination of AMI cost/benefit issues, should be deferred. *Central Maine Power Company Chapter 120 Information (Post ARP 2000) Transmission and Distribution Utility Revenue Requirements and Rate Design and Request for Alternative Rate Plan*, Docket No. 2007-215, Order Approving Stipulation (July 1, 2008).

Subsequent to the enactment of the American Recovery and Reinvestment Act of 2009, which included provisions for the Department of Energy to provide up to 50% of the costs of qualifying smart grid investments, the Commission concluded that it was reasonable and prudent for CMP to aggressively pursue opportunities for the cost

---

[1] Chairman Welch did not participate in this decision.

[2] As used in this Order, the term "project" is not limited to CMP's AMI capital Project but rather includes the full range of costs, savings and benefits presented by CMP at the time the AMI metering program was authorized by the Commission.

effective development of AMI and that it would allow full and timely cost recovery of CMP's prudently incurred AMI investment. The Commission noted that this cost recovery will occur according to Commission ratemaking practices and relevant prior commitments made by CMP. *Order Approving Installation of AMI Technology*, Docket No. 2007-215 (II) at 2 (July 28, 2009).

On January 19, 2010, CMP submitted testimony in support of its AMI project and corresponding ratemaking treatment. In its testimony, CMP stated that its AMI project was cost-effective and that it would provide approximately $25 million in net savings to ratepayers over 20 years, not including the benefits from demand response and other supply-side programs that will be available to customers once the AMI Project is in place.

A hearing on CMP's AMI Project was held on January 22, 2010. At the hearing, the Company's witness was questioned from the bench regarding CMP's prior estimates of net savings which had been greater than the $25 million number presented in the January 19, 2010 testimony. Specifically, the Company's witness, Paul Dumais, was asked whether CMP was confident that the current savings estimate would not undergo another major change. Mr. Dumais testified that the Company had given its most recent analysis a thorough vetting and had also done some independent modeling of the projections. Mr. Dumais testified that at that point, he had full confidence that the bugs in the projections were worked out.[3]

On February 25, 2010, based in large part on the estimates of net benefits provided by CMP and the expectation of additional benefits from electricity supply programs, the Commission issued an Order which approved CMP's AMI Project. *Order Approving Installation of AMI Technology*, Docket No. 2007-215(II) (Feb. 25, 2010). In doing so, the Commission concluded:

> The primary issue in this stage of the proceeding is to determine whether CMP's proposed AMI investment is reasonably likely to be cost-effective, taking into account both operational and supply-side benefits, the costs of the investment and possible risks involved with new technology. CMP has provided a cost-benefit analysis that shows with the DOE grant, its proposed AMI investment will result in approximately $25 million in operational savings over 20 years. This estimate does not include demand response and other supply-side benefits that will be available to customers once the AMI project is in place. Although the quantification of supply-side savings is, by its nature somewhat speculative, CMP estimates them to be over $338 million over 20 years.
>
> We have carefully reviewed CMP's analysis of the benefits and costs of its AMI proposal. We recognize the view of the Public Advocate and the IBEW that CMP's estimates of operational savings, because they are based on projections and assumptions, are necessarily speculative to

[3] Docket No. 2007-215(II), January 22, 2010 Hearing Tr. at 36.

> some degree. Moreover, we agree that the supply side benefits are difficult to quantify and uncertain by nature. However, based on the record in this proceeding, we find that it is reasonably likely that the operational and supply side savings over time will be substantially greater than the cost of the AMI investment. Accordingly, we approve CMP's proposed AMI project as described in its filing.

Id. at 6.

The Commission further noted that the approval of CMP's AMI project was explicitly premised on CMP's AMI's system having the following capabilities:

- Measuring and storing load on an hourly (or less) basis for residential and small commercial customers; a 15-minute interval basis for commercial and industrial (C&I) customers. The AMI system will have sufficient capacity to store the hourly billing data for load settlement processes, including potential adjustments and corrections.

- Measuring and storing the time-of-use (TOU) peak demands of each customer as necessary for billing and settling ICAP tags as well as each customer's daily peak demand.

- Back office and billing systems capable of billing, both transmission and distribution (T&D) and supply, on a TOU basis. These systems will be designed to allow for time periods that differ between T&D and supply and to allow hourly billing for large commercial and industrial customers. The billing and other back office systems will allow loads to be settled in the ISO-NE market systems for all customers based on actual hourly loads rather than load profiles and allow ICAP tags for all customers to be based on actual metered load in the applicable hour, rather than the load profile. The billing and back office systems will allow for multiple standard-offer products within a given standard offer class and allow for bill proration to be performed using metered loads rather than days in the period, as is currently done.

- Remote disconnections and reconnections.

- Reliably poll individual meters to evaluate outages and must include an outage tracking system.

- Monitoring and measuring voltage variances.

- Accommodate "value added" systems and devices (e.g., in-home displays; load control devices).

Id. at 7-8.

The Commission did not, as part of its February 25, 2010 Order determine a revenue requirement for the AMI investment or establish an amount that would be included in rates. Rather the Commission directed CMP to conduct a time study of the travel involved in disconnection and reconnection work and provide an update of the savings, included in the revenue requirement calculation, based on the time study as part of its 2010 annual Alternate Rate Plan (ARP) price change.

In May 2010, in its annual ARP price change case, CMP provided another update to its projection of net savings from AMI. In that filing, which included CMP's travel time study, CMP's estimate of net savings over the 20-year life of the AMI investment was projected to be $14 million. The parties and the Staff were not able to agree upon a revenue requirement figure at that time, and since May 2010, CMP has provided a number of updated revenue requirement calculations. In May 2013, the Company provided an updated AMI revenue requirement which revised the January 2010 projection of $25 million in net savings to approximately $127 million in net costs. Since that time the Company has reduced this amount to approximately $99 million. Based on the information provided to date, and adjusting for costs which were reasonably anticipated but not included in the initial revenue requirement calculation (such as the tax on the DOE grant for legacy meters and carrying costs on the deferral based on amounts CMP has accrued prior to including an amount in rates) and also for system refresh costs which were included in the calculation but now have been removed, we estimate the shift from CMP's January, 2010 projection of $25 million in net savings to the current projection of net costs to be an increase of approximately $80 million. While this calculation is only a preliminary estimate, this apparent shift from a net ratepayer benefit at the time AMI was authorized to a substantial net increase in costs now that the project has been completed and CMP is seeking to reflect AMI costs in rates, is of great concern to the Commission.

In addition to the mis-estimates and degradation of net savings on the T&D side, we are also concerned about the lack of capability to deliver customer benefits on the electricity supply side. As noted above, our approval was based, in part, on the expectation that AMI would enable customers to benefit from demand response and TOU/dynamic pricing programs. Indeed, the Order approving the project required that AMI include certain key capabilities to ensure these benefits would be realized. However, at this point, these benefits are not being realized, in part, because programs cannot currently be accommodated by CMP’s AMI and related systems.

Based on these concerns, we find that it is appropriate to initiate a management audit of CMP's AMI project pursuant to the provisions of 35-A M.R.S. § 113. The overall purpose of this management audit will be to determine why CMP's current estimates of net costs compared to its estimate of net savings as of January 2010 (which served as a basis for authorizing the project) are so different and why the AMI capabilities as expected in the Commission's Order have not been sufficiently implemented to allow customers to benefit from supply side programs. As part of this investigation the following questions will be addressed:

1. Whether CMP employed reasonable and prudent management practices in developing the savings estimates provided to the Commission in January 2010;

2. Whether CMP has employed reasonable and prudent practices in its management of the project and has acted in accordance with reasonable and prudent practices to ensure that actual operational costs and savings associated with the AMI project remained reasonably in line with estimates upon which approval of the project was authorized;

3. Whether CMP has appropriately and accurately identified the savings realized to date from the AMI project and provided reasonable estimates of these savings on a going forward basis;

4. Whether CMP has employed prudent and reasonable management to ensure that the AMI and related systems have the capabilities envisioned by the Commission at the time that the AMI system was approved.

The audit will be conducted pursuant to the provisions of 35-A M.R.S. § 113. As such, the Commission will select the auditor and CMP shall pay the costs of the audit.[4] These costs will be recovered from CMP's ratepayers. We find, given the potential impact of CMP's AMI revenue requirement on ratepayers, that any impact of the costs of the audit on ratepayers are warranted and further find that the audit is the most cost effective way to address the issues set forth above.

We expect that the results of the audit will inform our decision as to what amounts should be included in rates for AMI costs and savings. This decision will likely occur in the context of CMP's current rate case, Central Maine Power Company, Request for Approval of an Alternate Rate Plan (ARP 2014), Docket No. 2013-00168. We, therefore, will direct the auditor to complete its work in sufficient time for the parties to have an opportunity to address the findings made by the auditor and for the Commission to consider the auditors finding and parties presentations prior to the time that rates are scheduled to go into effect on July 1, 2014.[5]

---

[4] In its comments CMP suggested that the Commission select an auditor who has experience with AMI systems. While such experience may be relevant in selecting an auditor, to the extent that CMP is requesting that we include this as a requirement as part of our Order, we reject such a suggestion. The Commission will select the auditor that it determines to be the most qualified based on our evaluation of the responses the Commission receives in response to a competitive RFP process which will be initiated following the issuance of this Order.

[5] We set December 31, 2013 as the target date for the completion of the audit.

Dated at Hallowell, Maine, this 17th day of June, 2013.

BY ORDER OF THE COMMISSION

_______*/s/ Harry Lanphear*_______
Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR: Littell
Vannoy

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 11(D) of the Commission's Rules of Practice and Procedure (65-407 C.M.R. 110) within **20** days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought. Any petition not granted within **20** days from the date of filing is denied.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within **21** days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S. § 1320(1)-(4) and the Maine Rules of Appellate Procedure.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.

This page left intentionally blank.

Blue Ridge Consulting Services, Inc.

February 6, 2014

Paula Cyr
Maine Public Utilities Commission
House Station #18
Augusta, Maine 04333-0018

Re: Docket Nos. 2010-00051 CENTRAL MAINE POWER COMPANY Annual Price Change Pursuant to the Alternate Rate Plan - Report of Audit of Central Maine Power Company's Management of its Advanced Metering Infrastructure Program

Dear Ms. Cyr:

Blue Ridge Consulting Services, Inc. is pleased to submit to you for filing with the Commission the enclosed report of our audit of Central Maine Power Company's Management of its Advanced Metering Infrastructure Program. Blue Ridge believes its report provides a balanced, comprehensive review, providing appropriate findings and conclusions regarding the concerns of the Commission and Staff delineated in the audit scope.

The Blue Ridge team appreciates the opportunity to have worked with Staff on this audit.

Please feel free to contact me at (864) 331-0700 should you have any questions.

Sincerely,

Michael J. McGarry, Sr.
President / CEO

cc: Donna H. Mullinax, CPA, VP / CFO

Blue Ridge Consulting Services, Inc.

Report for:

OFFICE OF THE
Maine Public Utilities Commission
STATE OF MAINE

Audit of Central Maine Power Company's Management of its Advanced Metering Infrastructure Program

Submitted February 5, 2014

Prepared by
Blue Ridge Consulting Services, Inc.
2131 Woodruff Road
Suite 2100, PMB 309
Greenville, SC 29607
(864) 331-0700

TABLE OF CONTENTS

TABLES

DISCLAIMERS

The words *audit* and *examination*, as used in this report, are intended, as commonly understood in the utility regulatory environment, to mean a regulatory review, a field investigation, or a means of determining the appropriateness of a financial presentation for regulatory purposes. These terms are not intended in their precise accounting sense as an examination of booked numbers and related source documents for financial reporting purposes. Neither is the term *audit* in this case an analysis of financial statement presentation in accordance with the standards established by the American Institute of Certified Public Accountants. The reader should distinguish regulatory reviews such as those that Blue Ridge performs from financial audits performed by independent certified public accountants.

This document and the opinions, analyses, evaluations, and recommendations are for the sole use and benefit of the contracting parties. There are no intended third-party beneficiaries, and Blue Ridge shall have no liability whatsoever to third parties for any defect, deficiency, error, or omission in any statement contained in or in any way related to this document or the services provided.

This report was prepared based in part on information not within the control of the consultant, Blue Ridge Consulting Services, Inc. While it is believed that the information is reliable, Blue Ridge does not guarantee the accuracy of the information relied upon.

EXECUTIVE SUMMARY

In 2007, Central Maine Power Company ("CMP" or "Company") first proposed an Advanced Metering Infrastructure (AMI) Project ("AMI Program" or "Program"). Subsequently, in light of the American Recovery and Reinvestment Act of 2009, which included provisions for the Department of Energy to provide up to 50% of the costs of qualifying smart grid investments, the Maine Public Utilities Commission ("Commission" or "MPUC") deemed it reasonable and prudent for CMP to pursue opportunities for cost effective development of AMI. Based on Company-filed testimony and a hearing before the Commission in January 2010, the Commission approved CMP's AMI program.

Through subsequent filings, Commission Staff ("Staff") and the Commission grew increasingly concerned due to the changing projection for net savings in comparison with project costs. Additionally, certain benefits of the AMI Program expected by the Commission and Staff were either missing, delayed, or lacking automation. Based on these concerns, the Commission ordered an audit of CMP's AMI Program management.

The AMI Program deployment and implementation took place from February 2010 through December 2012 and included the installation of over 600,000 new meters and the infrastructure to remotely collect and administer individual customer data. The Program officially ended at the end of 2012. The 2013-updated AMI revenue requirement showed a revised projection from the initial January 2010 calculation of $25 million in net savings to approximately $127 million in net costs. (This figure was subsequently reduced to $99 million.)[1]

SCOPE

In its February 2010 Order approving the AMI Program, the Commission noted that approval of CMP's AMI Project was premised on the installed AMI system having the following capabilities:

1. Measuring and storing load on an hourly (or less) basis for residential and small commercial customers; a 15-minute interval basis for commercial and industrial (C&I) customers. The AMI system will have sufficient capacity to store the hourly billing data for load settlement processes, including potential adjustments and corrections.
2. Measuring and storing the time-of-use (TOU) peak demands of each customer as necessary for billing and settling ICAP tags as well as each customer's daily peak demand.
3. Back office and billing systems capable of billing, both transmission and distribution (T&D) and supply, on a TOU basis. These systems will be designed to allow for time periods that differ between T&D and supply and to allow hourly billing for large commercial and industrial customers. The billing and other back office systems will allow loads to be settled in the ISO-NE market systems for all customers based on actual hourly loads rather than load profiles and allow ICAP tags for all customers to be based on actual metered load in the applicable hour, rather than the load profile. The billing and back office systems will allow for multiple standard-offer products within a given

[1] MPUC Docket No. 2010-00051(ii), June 17, 2013, page 4.

standard offer class and allow for bill proration to be performed using metered loads rather than days in the period, as is currently done.

4. Remote disconnections and reconnections.
5. Reliably poll individual meters to evaluate outages and must include an outage tracking system.
6. Monitoring and measuring voltage variances.
7. Accommodate "value added" systems and devices (e.g., in-home displays; load control devices).

To address the Commission's (and its Staff's) concerns over functionality that was envisioned and the cost of the project (among other items), Blue Ridge Consulting Services, Inc. ("Blue Ridge") was selected through a competitive bid process to conduct the Commission's ordered management audit. Blue Ridge conducted an independent audit based on a workplan developed to address the Commission's concerns.

AUDIT PROCESS

Blue Ridge received notification of award of its bid for the audit on August 16, 2013. After contract negotiation and signing, the audit kicked off with a September 9, 2013, conference call. Blue Ridge immediately began is data management process which included the submittal of its first set of 29 data requests (DRs) to the Company on September 17, 2013. In total, Blue Ridge submitted 71 DRs in 9 submittal sets.

Blue Ridge traveled to Maine to meet with the Company during the week of October 7, 2013, to participate in an information-gathering meeting with the Company and to conduct interviews during that week. In total, Blue Ridge conducted interviews with twelve Company individuals, some of whom were interviewed more than once. Interviews were conducted with personnel in the following AMI Program areas:

- Executive Leadership & Program Steering Committee
- Program Lead
- Business Process
- Financials & Analysis
- Operations Technologies
- Research Study & Web Portal Redesign
- Meter & Systems Operations
- IT Lead CIS Integration
- Supply and Services / Settlement Group
- Regulatory Economics
- Customer Service
- Administrative Assistance

Included in Blue Ridge's development of this report were steps to ensure proper data-to-scope application as well as to ensure its factual content. As such, Blue Ridge provided draft copies of the report to both Staff and the Company for their review and comment. Blue Ridge carefully reviewed the comments and modified the draft for those items which needed factual correction or application clarity. Included as Appendices D & E are Staff's and CMP's comments respectively, to this report with Blue Ridge's response. However, the findings and conclusions of the report remain Blue Ridge's own assessment.

Throughout the audit process, Blue Ridge found the Company cooperative and interested in resolving issues. Blue Ridge enjoyed a good working relationship with CMP, finding Company personnel to be forthcoming in all areas.

FINDINGS AND CONCLUSIONS

Blue Ridge's findings and conclusions follow the four areas of review that the Commission directed to be addressed from the Commission's Order Initiating the Management Audit, Docket No. 2010-00051 (II), June 17, 2013. The conclusions are based on review of project documentation and response to data requests; interviews with key project personnel; analysis; and review of Commission Orders, Staff Bench Analysis, and Company testimony.

AMI Original Estimated Savings

"Investigate … Whether CMP employed reasonable and prudent management practices in developing the savings estimates provided to the Commission in January 2010

Based on the review of the Company's 5 dimensional approach to reviewing industry data and research material that it relied on in designing, costing, and implementing AMI, including (1) status review of its service territory for baseline information, (2) industry system and service provider data collected, (3) telephone and on-site interviews with AMI vendors and utilities that had deployed AMI systems, (4) AMI industry overview, and (5) published materials about AMI deployments, Blue Ridge found that the research of industry support was thorough and the process for moving from industry data to requests for proposals from vendors was reasonable. Furthermore, Blue Ridge found through review of CMP's descriptions of the expenditures, source assumptions behind the calculations, the actual model for the costs, which includes all calculations for each line item filed in January 2010 that the calculations were reasonable, accurate, and rigorous. Based on its review, Blue Ridge concluded that the Company's due diligence process in developing its original estimate was adequate and reasonable.

AMI Program Management

"Investigate … whether CMP has employed reasonable and prudent practices in its management of the project and has acted in accordance with reasonable and prudent practices to ensure that actual operational costs and savings associated with the AMI project remained reasonably in line with estimates upon which approval of the project was authorized and provide reasonable estimates of these savings on a going-forward basis?

Blue Ridge found that the Company project organization was staffed by well-qualified and experienced individuals from within the Company. In addition, we have established that senior management was effective in providing sufficient executive leadership and direction to the AMI Program. Further, the Team Leads understood their roles and exercised adequate day-to-day managerial supervision and problem solving throughout the AMI Program. Blue Ridge found that CMP's AMI Program Organization was effective in providing reasonable managerial oversight of the AMI Program and related projects.

We found through review of Program documents, interviews, and data responses that the Company executed the documented plan for the Program. The Company's documented processes included sufficient detail and covered the expected areas in order to provide proper guidance for the managerial oversight of the Program.

Through its review of AMI Program reports, Blue Ridge found that appropriate reporting was communicated at an effective frequency to maintain reasonable oversight of the Program implementation status. Blue Ridge reviewed selected reports for content, identification of issues, compliance with Company policies and procedures, DOE requirements, and active participation by the AMI Project team. We found that the reports were in compliance with Company and DOE requirements and that the AMI Program team members were active participants in the process.

The Company's AMI Governance Plan provided adequate guidance for reasonable and prudent control of budget and cost. The reports distributed during the Program implementation and the information that was communicated were sufficient to reasonably control costs. While the Governance Plan anticipated a more formal, less pro-active process through e-mail communication, by immediately reporting variance explanations along with discussion of mitigation strategies, the PMO as well as all Program participants were kept apprised of budget and cost activity without the more time-consuming delays and less availability involved in the email exchange first envisioned.

Blue Ridge reviewed the Company's original outsourcing selection plan; the vendor and contractor procurement procedures; and the bid packages for the AMI Program system contractors, consultants, and vendors. Based on the consistency with internal requirements and thoroughness of data required, Blue Ridge determined that the plan and procedures were reasonable. Furthermore, the level of oversight that the Company provided for outsourced contractors appeared adequate. Additionally, from the information provided, Blue Ridge found that the Company's decisions regarding outsourcing authorizations using criteria corresponding to each of the vendor contract provisions were reasonable.

Blue Ridge reviewed the Company's master schedule, timeline, various progress reports, including the monthly status updates to the DOE, the weekly reviews of the Integrated Project Plan, and the weekly status reports to the team and Steering Committee, and found that both the management of the schedule and the completion of the activities were timely, cost effective, and reasonable.

Therefore, Blue Ridge found that the Company did employ reasonable and prudent practices in its management of the project and has acted in accordance with reasonable and prudent practices to ensure reasonable control of the Program implementation.

AMI Budget and Cost

"Investigate ... whether CMP has appropriately and accurately identified the savings realized to date from the AMI project and provided reasonable estimates of these savings on a going-forward basis."

The Company originally estimated that the capital cost to complete the AMI Program would be $163.8 million. This amount was later revised to include the net book value ("NBV") of existing legacy analog/mechanical meters which increased the total program costs by $27.9 million to $191.7 million.[2] The NBV of the legacy meters represents the un-depreciated value of the legacy meters that were replaced with AMI meters. With the grant resulting from the passage of the ARRA, the DOE contributed $95.9 million to the project, which included 50% of the NBV of the legacy meters. Based on Blue Ridge's review of initial costs, changes to cost over the duration of Program implementation, and the resultant cost of the project, we determined that (1) the cost of the project was adequately supported and (2) the resultant total cost appears reasonably in line with initial estimates.

Blue Ridge's review of the contractor scope changes showed that the Company reviewed, justified, and controlled scope changes made by the various vendors and contractors on the project.

[2] MPUC Docket No. 2007-215(ii), February 25, 2010.

Blue Ridged calculated that the total impact of the scope changes on total project costs was less than 6%. We believe that, given the magnitude of the AMI program, this change to contractor costs does not reflect unreasonable change, especially considering the Company's procedural control and oversight.

In the Order Initiating the AMI Management Audit dated June 17, 2013, the Commission identified a significant variance of approximately $80 million between the January 2010 estimated net savings and the adjusted projection of the Company's March 2013 filing. This variance was in part the reason for the Commission ordering this audit.

The January 2010 cost-benefit estimate contained savings for 2009 through 2013 using an annual savings based on 2006. The estimate also contained savings for 2014 through 2032 using an annual savings based on 2008.[3] The Company adjusted these annual savings amounts (base year 2006 of $7.55 million and base year 2008 of $7.95 million) for the August 2012 filing. In that filing, the 2006 base year savings changed to $7.36 million, while the 2008 base year savings changed to $7.74 million.[4] Blue Ridge issued a data request to the Company to reconcile this August 2012 net savings amount with the March 2013 filing which showed a net cost rather than net savings.

In response to Blue Ridge's data request, the Company noted that the difference between the August 2012 filing and the March 2013 filing was about $82 million. CMP indicated that these two filings were not developed by the same method and it was therefore difficult for an apples-to-apples comparison.[5]

However, based on explanations provided in interviews, Blue Ridge's review of the detailed support of Company documents regarding the August 2012 to March 2013 comparison, and the other documents providing savings and cost data received through data requests, Blue Ridge believes the Company satisfactorily explained the variance between the net savings of the cost-benefit analysis method in filings from January 2010 to August 2012 and the cost and savings reported in the March 2013 filing. For example, a significant variance between the August 2012 filing and the March 2013 filing included Customer Relations Center Savings of $17.5 million. The Company's August 2012 analysis included avoided costs that would have occurred but for the AMI project. However, the Company's intent in March 2013 was to provide only a one-year rate impact of AMI (including incremental savings).

AMI Capabilities

"Investigate … whether CMP has employed prudent and reasonable management to ensure that the AMI and related systems have the capabilities envisioned by the Commission at the time that the AMI system was approved."

Blue Ridge understands that Staff and the Company have continued to meet to resolve issues of AMI system capabilities even throughout this audit. Therefore, Blue Ridge's assessment may not have the most current information agreed to from those meetings.

However, the following capabilities are not yet in place:

1. Critical Peak Pricing – expected by year end 2014
2. Hourly billing for large commercial and industrial customers can be supported manually

[3] CMP Data Response: BRCS-001-013, attachments 6 and 7.
[4] CMP Data Response: BRCS-001-011, attachments 25 and 26.
[5] CMP Data Response: BRCS-002-011 Supplemental.

Based on information provided by the Company, the interim billing solution, which is expected to include the dynamic pricing capabilities, will be implemented by the end of 2014.[6]

In interviews, the Company confirmed that both of these capabilities will be addressed during this calendar year. Therefore, Blue Ridge found that Commission's and Staff's concern is based in fact. Nothing that the Company has provided Blue Ridge through the audit process suggests otherwise. The Commission and Staff expected dynamic pricing available for all participants in the energy market, i.e., residential, small and large commercial, and industrial, and competitive energy providers - supply.

It is clear to Blue Ridge that, at the very least, time-of-use pricing is available for the delivery component of the customer's bill and for the standard offer service. However, based on all of the information provided, it is also clear the Critical Peak Pricing will not be available until the end of 2014.[7] It is also clear that in the Commission's order in the dynamic pricing case (2010-0132), the Commission stated, "CMP should program its systems to be able to broadly offer at least two pricing options; TOU and CPP pricing options (as well as an alternative that combines both pricing approaches)." The Commission also stated:

> With respect to hourly pricing, we understand that it is impractical for CMP to design its systems to allow for the prospect of a large number of its customers choosing this option, especially when only a small percentage of customers are likely to do so. However, we expect CMP to design its systems, within reasonable cost limitations, so that at least some percentage of CMP customers could take advantage of an hourly pricing alternative.[8]

Blue Ridge also found that, based on its review, including interviews, data requests, the Company's testimony in Docket 2007-215, and subsequent filings, CMP had committed to provide supply-side dynamic pricing options. One document in particular, ***CMP's AMI Project Execution Plan,***[9] clearly states, "to enable electricity suppliers to create dynamic pricing options for customers."[10] Further, this plan states that one of the benefits of the AMI system would be "[a]n updated customer billing system to support new incentive rates that [*sic*] **expected from the Maine PUC and from third-party energy providers**." (*emphasis added*)[11]

Based on this information, there is little room to allow a "benefit of the doubt" that the Company's interpretation of what was intended at the outset of the implementation of AMI was different from what the Commission and/or Staff believed the Company promised. However, it is not clear in either the Project Execution Plan or the System Integrator work scope where this capability—dynamic pricing for suppliers—was addressed. Blue Ridge reviewed the system integrator RFP work scope and could not find where the capability to offer TOU pricing on the supply side was ever contracted out. Therefore, it is not clear that CMP actually included work steps to implement this function.

That said, the fact remains that CMP's system as it stands now does not support the depth of what the Commission envisioned in its approval of the AMI Program on the supply side for TOU or

[6] BRCS-008-009 Att. 1, Page 10 of 23 Docket No. 2013-00476 (**CONFIDENTIAL)**
[7] See BRCS-001-030 Attachment 1 page 1.
[8] MPSC Order – Docket No. 2010-0132, dated March 12, 2012, page 4-5
[9] Provided in response to BRCS-001-002 Attachment 3
[10] Ibid. at page 6 of 28
[11] Ibid.

CPP. However, the Company provided sufficient information that these issues will be addressed with the new billing system.

What remains to be determined, then, is whether the cost of meeting the Commission's original expectations, which Staff may argue would have been included in the original AMI Program cost approval, is now being included in the new billing system that is the subject of the current rate case. In data responses and interviews, the Company has confirmed that some of the costs (approximately $4.3 million in capital and O&M) are related to the dynamic pricing issue and providing the capability that the Commission expects. This gives rise to the question: *"Is the Company asking to be paid twice for the same capability?"*

Blue Ridge has reviewed the relevant data requests, documents, and through the interview process concluded that with respect to the supply side, it is not likely that the original project cost estimate, while well developed, included this capability. However, given the complexity and number of contractors that were utilized, it is possible that the work scope was included.

Blue Ridge found that the Company has implemented a significant portion of the capabilities and functionality the Company presented in its initial and subsequent filings requesting approval for AMI. However, the dynamic pricing issue for the supply side has not been fully implemented but will be addressed in the new billing system. While Blue Ridge did not find evidence that CMP paid for a capability it did not implement, the possibility does exist that some project funds were allocated to complete this function which was not delivered. However, what is lost is the potential savings value of the dynamic pricing option that customers (and suppliers) may have taken advantage of had the capability been available.

INTRODUCTION

BACKGROUND

In Case No. 2007-215, Central Maine Power Company ("CMP" or "Company") proposed an Advanced Metering Infrastructure (AMI) Project ("AMI Program" or "Program").[12] While the proposal of that program was initially deferred to continue cost benefit analysis, to take advantage of the subsequently enacted American Recovery and Reinvestment Act of 2009 (ARRA),[13] the Maine Public Utilities Commission ("Commission" or "MPUC") granted approval for CMP to pursue opportunities for cost effective development of AMI and stated that it would allow full and timely cost recovery of CMP's prudently incurred AMI investment.[14] The Company filed additional specific testimony related to its AMI Program in January 2010 and in a hearing before the Commission in Case No. 2007-215 (Phase II), CMP presented its proposed AMI Program. In that case, CMP estimated net savings to ratepayers over 20 years of approximately $25 million. On February 25, 2010, the Commission issued an Order approving CMP's AMI Program.[15]

In this Order, the Commission noted that approval of CMP's AMI Project was premised on the installed AMI system having the following capabilities:

1. Measuring and storing load on an hourly (or less) basis for residential and small commercial customers; a 15-minute interval basis for commercial and industrial (C&I) customers. The AMI system will have sufficient capacity to store the hourly billing data for load settlement processes, including potential adjustments and corrections.
2. Measuring and storing the time-of-use (TOU) peak demands of each customer as necessary for billing and settling ICAP tags as well as each customer's daily peak demand.
3. Back office and billing systems capable of billing, both transmission and distribution (T&D) and supply, on a TOU basis.
    a. These systems will be designed to allow for time periods that differ between T&D and supply and to allow hourly billing for large commercial and industrial customers.
    b. The billing and other back office systems will allow loads to be settled in the ISO-NE market systems for all customers based on actual hourly loads rather than load profiles and allow ICAP tags for all customers to be based on actual metered load in the applicable hour, rather than the load profile.

---

[12] Once approved CMP referred to the AMI Project as the AMI Program to distinguish the overall scope ("Program") from the specific "projects" that made up the Program.
[13] The American Recovery and Reinvestment Act included provisions for the Department of Energy to provide up to 50% of the costs of qualifying smart grid investments including AMI
[14] Order Approving Installation of AMI Technology, Docket No. 2007-215 (II), July 28, 2009.
[15] Order Approving Installation of AMI Technology, Docket No. 2007-215 (II), February 25, 2010.

c. The billing and back office systems will allow for multiple standard-offer products within a given standard offer class and allow for bill proration to be performed using metered loads rather than days in the period, as is currently done.

4. Remote disconnections and reconnections.
5. Reliably poll individual meters to evaluate outages and must include an outage tracking system.
6. Monitoring and measuring voltage variances.
7. Accommodate "value added" systems and devices (e.g., in-home displays; load control devices).

In March 2011 filing, CMP proposed an AMI revenue requirement increase from the $523,000 in January 2010 to $1.4 million as the levelized Revenue Requirement for Distribution.[16] On April 14, 2011, the Commission Staff ("Staff") responded in a bench analysis to the Company's proposed revenue requirement increase. Staff suggested several adjustments including the following:

- CMP's estimate of O&M savings be increased by a factor of 2.5 or $5.2 million per year, based on actual time records
- Removal of future estimates of "refresh" costs ($13.2 million revenue requirement effect)

[16] Annual Price Change Pursuant to the Alternate Rate Plan, Docket No. 2010-051, Phase II, Letter from CMP March 11, 2011, page 4.

- Utilization of a 100% bonus depreciation rate
- "Placeholder" adjustment for costs not yet justified by CMP, due to the difficulty in mapping costs from those projected at approval to those in the most recent filings, results in a reduction of approximately $18.8M during deployment and $9.6M, post-deployment

These adjustments had the effect of reducing the Company's proposed revenue requirement increase of $1.4 million by $5.9 million to equate to a savings of $4.5 million.

In subsequent filings, the Company's estimate of net savings changed. Furthermore, the Commission and its Staff have expressed concerns that the capabilities specified in its February 2010 Order have not been realized in the completed AMI system.

Based on these concerns (changed net savings and lack of capabilities implemented), in 2013, the Commission ordered a management audit to determine the following: [17]

(1) The reason for the significant change in net savings

(2) The reason CMP's AMI capabilities as expected in the Commission's Order have not been sufficiently implemented to allow customers to benefit from supply side programs

The Commission's Order initiating this management audit included investigation of the following issues:

1. Whether CMP employed reasonable and prudent management practices in developing the savings estimates provided to the Commission in January 2010
2. Whether CMP has employed reasonable and prudent practices in its management of the project and has acted in accordance with reasonable and prudent practices to ensure that actual operational costs and savings associated with the AMI project remained reasonably in line with estimates upon which approval of the project was authorized
3. Whether CMP has appropriately and accurately identified the savings realized to date from the AMI project and provided reasonable estimates of these savings on a going-forward basis
4. Whether CMP has employed prudent and reasonable management to ensure that the AMI and related systems have the capabilities envisioned by the Commission at the time that the AMI system was approved

Blue Ridge Consulting Services, Inc. ("Blue Ridge") was selected through a competitive bid process to conduct a focused management audit of CMP's AMI Program that would investigate these issues. This report seeks to address the four major scope areas identified in the Order.

Therefore, this report is organized according to these four major issues:

1. AMI Original Estimated Savings
2. AMI Program Management Oversight
3. AMI Program Budget and Cost
4. AMI Program Capabilities

[17] Order Initiating Management Audit, Docket No. 2010-00051 (II), June 17, 2013.

AUDIT PROCESS

Blue Ridge received notification of award of its bid for the audit on August 16, 2013. After contract negotiation and signing, the audit kicked off with a September 9, 2013, conference call. Blue Ridge immediately began its data management process which included the submittal of its first set of 29 data requests (DRs) to the Company on September 17, 2013. In total, Blue Ridge submitted 71 DRs in 9 submittal sets.

Blue Ridge traveled to the Company in October 2013, to participate in an information-gathering meeting with the Company and to conduct interviews. In total, Blue Ridge conducted interviews with twelve (12) Company individuals, some of whom were interviewed more than once. Interviews were conducted with personnel in the following AMI Program areas:

- Executive Management and Program Steering Committee
- Program Lead
- Business Process
- Financials & Analysis
- Operations Technologies
- Research Study & Web Portal Redesign
- Meter & Systems Operations
- IT Lead CIS Integration
- Supply and Services / Settlement Group
- Regulatory Economics
- Customer Service
- Administrative Assistance

Included in Blue Ridge's development of this report were steps to ensure proper data-to-scope application as well as to ensure its factual content. As such, Blue Ridge provided draft copies of the report to both Staff and the Company for their review and comment. Blue Ridge carefully reviewed the comments and modified the draft for those items which needed factual correction or application clarity. Included as Appendices D & E are Staff's and CMP's comments respectively, to this report with Blue Ridge's response. However, the findings and conclusions of the report remain Blue Ridge's own assessment.

Throughout the audit process, Blue Ridge found the Company forthcoming, candid, cooperative, and interested in resolving issues. Blue Ridge wishes to acknowledge that cooperation as it made the audit process effective and efficient.

AMI PROGRAM HISTORY

CMP first introduced its proposed AMI Program in its rate case filed in May 2007. The parties to the Stipulation resolving that rate case agreed to defer a decision on AMI pursuit given its complexity and in the interest of further examination of cost/benefit issues. In 2009, the American Recovery and Reinvestment Act included provisions for the Department of Energy to provide up to 50% of the costs of qualifying smart grid investments. Based on this opportunity, the Commission determined that it was reasonable and prudent for CMP to pursue AMI opportunities, and that it would allow recovery of prudently incurred cost. On January 19, 2010, CMP submitted testimony in support of its AMI project. In that testimony, CMP provided its estimates that the Program would provide approximately $25 million in net savings to ratepayers over 20 years. Based largely on the estimates of the benefits provided by CMP, the Commission approved CMP's AMI Program in February 2010.

The February 2010 Order also specified that CMP would perform a time study of the travel involved in a sample of the disconnection and reconnection work during the months of April and May 2010. Subsequent to the time study, an updated AMI Revenue Requirement was filed in May 2010. Additional filings were made throughout the Program implementation timeframe, including those in July 2010, March 2011, July 2011, August 2012, and March 2013.

The Company implemented the program to install the AMI meters for its more than 600,000 customers and constructed the network and infrastructure from February 2010 through December 2012. CMP has reported that the AMI Program was officially completed at the end of December 2012.

1. AMI ORIGINAL ESTIMATED SAVINGS

In order to address the Commission's concern *"Whether CMP employed reasonable and prudent management practices in developing the savings estimates provided to the Commission in January 2010,"* Blue Ridge developed its work plan according to the following criterion: what was the Company's due diligence process that developed their original project cost of $163.8 million that, when compared with the AMI Program's proposed operational and avoided cost savings, resulted in an approximate project net savings of $25 million?

To answer this question, Blue Ridge submitted several data requests and interviewed key personnel to determine the due diligence process the Company used. Blue Ridge found that CMP utilized a 5 dimensional approach to reviewing industry data and research material that they relied on in designing, costing, and implementing AMI:[18]

- CMP reviewed the status of its service territory infrastructure and customer meter population, in order to provide an accurate baseline from which to estimate equipment costs and levels of installation and deployment effort.
- CMP collected information from industry system and service providers through a 2009 RFI and RFP. The 2009 RFI was distributed to insure that the RFP would be directed to well-qualified vendors. The subsequent 2009 RFP was distributed to collect detailed performance and pricing information from well-qualified bidders.
- CMP undertook a series of telephone and on-site interviews with AMI vendors and with utilities that had deployed AMI systems. These interviews were shaped by, and complemented with, information collected at the key industry trade-show meetings such as Distributech and Utilimetrics. The interviews were used to collect lessons learned and insights from other utilities that might not be revealed in vendor responses to the RFP.
- CMP completed an AMI industry overview that took a comprehensive look at how utilities were deploying and using AMI. This overview was undertaken to uncover the challenges and opportunities utilities were experiencing with AMI deployment.
- CMP reviewed published materials about AMI deployments in North America. This review was undertaken to identify special concerns or opportunities emerging with utilities as they deployed AMI.

In September 2009 the Company filed a confidential report with the Commission on the AMI Industry along with updates through the fourth quarter of 2009. As part of its support material for its 2009 report, the Company provided three reports developed by FERC on the AMI industry.[19] The

[18] CMP Data Response: BRCS 001-007.
[19] CMP Data Response: BRCS-001-007, attachments 32, 33, and 34.

report also discussed all the leading technology vendors. The Company, through the bidding process, selected several of these vendors. Blue Ridge was provided all support documentation from the industry data-gathering effort.

Using the information gathered through their review of industry data, CMP developed its AMI Project O&M and capital costs. CMP provided to Blue Ridge the descriptions of the expenditures, source assumptions behind the calculations, and the actual model for the costs, which includes all calculations for each line item filed in January 2010.

Blue Ridge reviewed all of the information that the Company provided and determined that the industry support was thorough, the process for moving from industry data to requests for proposals from vendors was reasonable, and the calculations were reasonable, accurate, and rigorous. Based on its review, Blue Ridge concluded that the Company's due diligence process in developing its original estimate was adequate and reasonable.

The Company provided detailed support for the expected savings to be achieved through the AMI project as filed in Docket No. 2007-215 (II) on January 19, 2010.[20] [21] Those savings were developed using 2006 as a base year for years 2009 through 2013, and using 2008 as a base year for years 2014 through 2032. These one-year base savings amounts were projected to be as follows:

Table 1 Expected Savings[22]

	2009-2013	Beginning 2014
Meter Reading Savings	$4,801,727	$ 5,096,065
Off-Cycle Reads	$ 663,914	$ 704,668
Meter Services	$ 292,825	$ 262,935
Customer Relations Center	$ 454,368	$ 511,808
Remote Reconnect/Disconnects	$ 921,540	$ 978,108
Cash Flow Savings	$ 207,946	$ 214,544
Storm Costs	$ 165,865	$ 136,302
Billing	$ 46,475	$ 48,725
Total	**$7,554,660**	**$7,953,155**

Meter Reading – The Company anticipated a reduction of 94 FTE (Full Time Equivalent) employees resulting in the projected savings. Future savings projections would adjust updated wage, overhead, and vehicle assumptions, but not FTE reduction numbers.

Off-Cycle Reads – CMP determined a reduction of 10 FTEs in this area.

Meter Services – For this category, the Company eliminated annual maintenance fees for the then-current AMR system, MV-90, and customer communications charges for MV-90.

Customer Relations Center – Based on the new AMI system, an anticipated call reduction was assumed related to usage and estimated bill inquiries. The reduction was based on 2008 call volume data. The reduced call volume was expected to allow a reduction of 8 FTEs.

Remote Reconnect/Disconnects – A reduction of 14 FTEs was anticipated for this area.

---

[20] MPUC Docket No. 2007-21511, attachment 4, Part 1.
[21] CMP Data Response: BRCS 001-013, attachment 3.
[22] CMP Data Response: BRCS 001-008, attachment 1, pages 1-3.

Cash Flow Savings – By using the AMI system, CMP estimated that it could reduce by one day the time between the meter read and bill issuance. Thus, the Company anticipated receiving payment one day earlier. Additionally, summary billing for customers with multiple accounts would be improved such that CMP would receive payment from these customers 15 days earlier.

Storm Costs – CMP anticipated a storm cost reduction of 10% of incremental costs for all storms with incremental costs over $150,000. These cost savings include such items as overtime, meals, contractors, and some payroll taxes.

Billing – The Company expected a reduction of one billing analyst for this area.

Additionally, in the January 2010 filing, the Company projected O&M savings related to the reduction of 141 positions, which equates to 129 FTEs (before the five additional positions required by AMI). The final total FTE reduction is 124 which was due in part to several engineering and administration position not included in the original plan.

As a result of a time study[23] in May 2010, the estimate was reduced by 3 positions to 138 positions, which equated to 126 FTEs from Meter Reading, Service Work, Customer Relations Center, Meter Operations, and Billing Department.[24] Blue Ridge calculated the 126 FTEs as follows:

Table 2 Blue Ridge's Calculation of the 126 FTEs

Positions	FTE
Meter Reading	77
Off Cycle Reads	10
Customer Relations Center	8
Remote Rec/Disc	14
Billing	1
Subtotal	110
Add'l 31 Part Time and Seasonal Workers	16[25]
Total	126

The actual FTE reductions were 93 based on comparing 2009 to 2013. The Company did not specify where those reductions took place.[26] Even though the Company did not meet the original estimated reductions of FTEs they did make substantial reductions in head count.

With respect to savings, the Company originally projected $25 million in net operational savings over a 20-year period based on their revenue requirement projection in January 2010. Those benefits excluded supply side benefits such as allowing for time periods that differ between T&D and supply while allowing hourly billing for large commercial and industrial customers and demand response available to customers once AMI was in place. Also, the Company believed that substantial additional benefits might accrue to customers in reduced customer outage costs, web portal benefits, and demand response benefits.[27]

Regarding net savings, Blue Ridge noted the following:

---

[23] CMP Data Response: BRCS 001-011.
[24] CMP Data Response: BRCS 008-001, attachment 1.
[25] Part Time estimated at half of FTE
[26] CMP Data Response: BRCS 008-001.
[27] MPUC Docket No. 2007-215(ii), February 25, 2010.

1. The total project amount subject to 50% reimbursement by the DOE was approximately \$191.7 million (with Legacy meters). The DOE grant reduced the net cost of the project to CMP and its ratepayers to approximately \$96 million.
2. The initial total actual capital cost of the project was \$167.18 million.
3. The Company was responsible for half the project costs eligible for reimbursement or approximately \$83.6 million (\$167.2/2).
4. The Company was reimbursed from the DOE for half of the net book value of the legacy meters (total subject to DOE reimbursement \$191.7 million less original project estimate \$163.8 million) / 2 = \$14 million, which was the original estimate; actual net book value of legacy meters was \$10.8 million.

Therefore, the unreimbursed cost in total was approximately \$94.4 million (\$83.6 plus \$10.8 million).

The estimated savings were to take place over 20 years.[28]

The original expected cost to CMP for the project was \$81.9 million. This is calculated based on a total cost projection of \$163.8 reduced by half due to DOE's 50% grant. The original expected operational and avoided cost savings related to the AMI program was approximately \$107 million. Therefore, cost and savings integration resulted in net savings of approximately \$25 million (\$107 million in savings minus \$81.9 million in costs).

The estimated savings, as noted above, was due in large part to the reduction of FTEs. As mentioned, 5 FTEs were expected to be added in the original estimate based on needs of the AMI system. That number was adjusted upwards to 14 FTEs for operational support in subsequent filings. However, the number of FTEs reduced (originally 126 but, with the 14 FTE increase, only 112) still resulted in significant savings. The Company has stated that these employee reduction numbers will not change in all future AMI cost savings updates. The only adjustment will be for escalation and a 1% productivity factor.[29]

A. Overall Conclusion for AMI Program Savings

Based on the review of the Company's 5 dimensional approach to reviewing industry data and research material that they relied on in designing, costing, and implementing AMI, including (1) status review of its service territory for baseline information, (2 industry system and service provider data collected, (3) telephone and on-site interviews with AMI vendors and utilities that had deployed AMI systems, (4) AMI industry overview, and (5) published materials about AMI deployments, Blue Ridge found that the industry support was thorough and the process for moving from industry data to requests for proposals from vendors was reasonable. Furthermore, Blue Ridge found through review of CMP's descriptions of the expenditures, source assumptions behind the calculations, the actual model for the costs, which includes all calculations for each line item filed in January 2010, that the calculations were reasonable, accurate, and rigorous. Based on its review, Blue Ridge concluded that the Company's due diligence process in developing its original estimate was adequate and reasonable.

[28] CMP Data Response: BRCS 001-008, attachment 1, pages 1-3
[29] CMP Data Response: BRCS 001-008, attachment 1.

2. AMI PROGRAM MANAGEMENT OVERSIGHT

In this area, Blue Ridge addresses the Commission's concern, *"Whether CMP has employed reasonable and prudent practices in its management of the project and has acted in accordance with reasonable and prudent practices to ensure that actual operational costs and savings associated with the AMI project remained reasonably in line with estimates upon which approval of the project was authorized."*

To investigate this, Blue Ridge evaluated whether the Company's AMI Program managerial oversight was sound and reasonable. This would include whether CMP's AMI Program organization was adequate and whether policies and procedures were thorough and known to those who were responsible for the projects within the AMI Program. Additionally, the Company's communication and reporting during the AMI Program's development and implementation was reviewed. Likewise, Blue Ridge reviewed specific project reporting related to project cost and savings to understand how the Company used this important information as the AMI Program moved thorough the various phases on implementation and deployment. Outsourcing plans as well as scheduling and scope changes are additional areas of control that are required for effective project management and were reviewed by Blue Ridge.

Blue Ridge examined all these areas to determine whether CMP exercised effective and reasonable control of its AMI Program implementation.

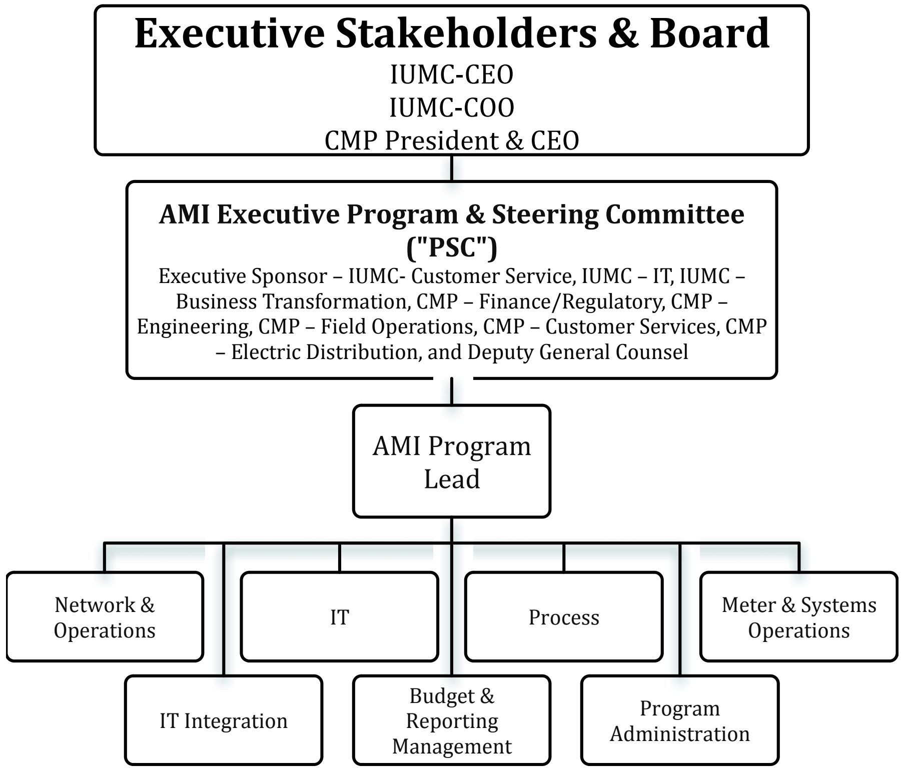
A. AMI PROGRAM ORGANIZATION

Proper project management, for projects in which millions of dollars are at risk, starts with the project organization. This includes that level of senior management involvement in the project oversight and management and whether the project team leads are well-qualified to lead the area of responsibility. The project team should understand roles and responsibilities and reporting relationships so that clear lines of authority are understood and can be effective in maintaining proper control.

Blue Ridge reviewed CMP AMI Program organization and found that it was broadly organized in the following manner:

Audit of Central Maine Power Company's
Management of its Advanced Metering Infrastructure Program

Figure 1 AMI Program Organization Chart[30]



There were three Executive Stakeholders for the AMI Program, including the IUMC-CEO, IUMC-COO and CMP President and CEO. The Executive Stakeholders were responsible for approving the formation of the Program Steering Committee and for approving the governance of the AMI Program. [31]

The Program Steering Committee had the following roles and responsibilities:[32]

- Ensure strategic alignment, priority, overall budget, and delivery
- Provide approval of overall AMI Program scope, strategy and direction
- Provide approval of AMI Program goals, objectives, and performance targets
- Provide approval of AMI Program budget and securing of Program funding
- Provide approval of Change Requests as set out in the escalation matrix in section 3.7
- Provide required decision making or approvals related to risks or issues escalated to the PSC as defined in section 3.6
- Approve Go-Forward Decisions, at the recommendation of the Program Leadership Team, at key stages of the Program, as defined in the integrated program schedule
- If necessary, identify a proxy by notification to the Executive Sponsor
- Meet every three weeks – meetings will be chaired by the AMI Program Lead
- Publish minutes of PSC meetings

[30] CMP Data Response: BRCS-001-006, Attachment 1 (CMP AMI Governance).
[31] CMP Data Response: BRCS-001-006, Attachment 1 (CMP AMI Governance).
[32] CMP Data Response: BRCS-001-006, Attachment 1 (CMP AMI Governance).

The Program Leadership Team was made up of the Program Lead and the leads of each of the major projects:[33]

- Laney Brown – AMI Program Lead
- John Miller – Network and Operations Program Lead
- Donna McNally – IT Program Lead
- Brenda Benner – Process Lead
- Steve Faulhaber – Meter and Systems Operations Lead
- Amy Easterling – IT Integration Lead
- Mary Alice Laiho – Budget & Reporting Management
- Donna White – Program Administration

The Program Leadership Team had the following roles & responsibilities:[34]

- Manage and control AMI Program delivery
- Manage strategic program alignment and priorities
- Manage, control and report on AMI Program budgets
- Sign-off on project approach, overall design, and schedule
- Approve, reject, or defer projects within the AMI program
- Provide leadership to project resources
- Approve and allocate project resources
- Include key supplier partners to ensure project alignment and results
- Provide approval of Change Requests as identified in the escalation matrix in section 3.6
- Provide required recommendations, decisions or approvals related to program risks or issues escalated to the PSC as defined in section 3.7
- Identify projects within the AMI program that have dependencies upon one another, and the status of those dependencies.
- Recommend items, outside of the pre-determined parameters, for escalation to the Program Steering Committee
- Meet on a weekly basis

The Program Management Office ("PMO") had the following roles & responsibilities:[35]

- Ensure that the overall program structure and program management processes enable the component teams to successfully complete their work and that the deliverables can be integrated into the AMI program's end product, service, results, and/or benefits
- Participate in the prioritization, scheduling, and resolution of conflicts for projects within the AMI Program.
- Own and manage the Integrated Project Plan and Schedule
- Monitor and manage program budget contingency
- Create and distribute program status reporting
- Track and report on program-level risks and issues
- Track and report on program Change Requests
- Oversee quality management across the AMI program and the communication of the results from the quality management execution

[33] CMP Data Response: BRCS-001-006, Attachment 1 (CMP AMI Governance).
[34] CMP Data Response: BRCS-001-006, Attachment 1 (CMP AMI Governance).
[35] CMP Data Response: BRCS-001-006, Attachment 1 (CMP AMI Governance).

- Provide reports to AMI Program Lead, Leadership Team and Program Steering Committee
- Provide administrative support to the Program Leadership Team

Conclusion

Blue Ridge found that the Company project organization was staffed by well-qualified and experienced individuals from within the Company. In addition, we have established that senior management was effective in providing sufficient executive leadership and direction to the AMI Program. Further, the Team Leads understood their roles and exercised adequate day-to-day managerial supervision and problem solving throughout the AMI Program. Blue Ridge found that CMP's AMI Program Organization was effective in providing reasonable managerial oversight of the AMI Program and related projects.

B. POLICIES AND PROCEDURES

Blue Ridge evaluated the Company's AMI Program implementation policies and procedures. Blue Ridge found that CMP followed a standard review process for all regulatory analysis and filings that included legal counsel and regulatory senior management.[36] Additionally, the Company developed an AMI Project Execution Plan,[37] which provided information and guidelines concerning management structure, governance, performance management, risk management, and problem issue management.

The AMI Program Governance Plan and the Project Management Office ("PMO") were formalized and approved by the Steering Committee in May 2010. The AMI Governance Plan[38] (more detailed than the Project Execution Plan) was a "road-map" enabling the effective day-to-day (operational) management and control of the program. The Governance Plan was the principal means by which the Program was planned, monitored, and delivered. The objectives of the AMI Program Governance document follow:

- To establish the program governance and leadership structure, including the Program Steering Committee ("PSC") and the Program Leadership team
- To establish the roles, responsibility, and authority for the Program Steering Committee, the Program Leadership team and the individual project teams
- To establish clear guidelines for communication within the program, including reporting to the Program Leadership team and the Steering Committee and pre-defined, re-occurring leadership meetings
- To establish program risk management methods
- To establish program issue management methods
- To define the approvals process for key program deliverables
- To document the processes and tools that will be used to manage the program, in terms of cost, schedule, scope, and risk

The Governance Plan details 'how' the Program teams carry out their tasks and activities to ensure that the 'what' will occur.[39] In addition to the governance framework and processes

[36] CMP Data Response: BRCS-001-001.
[37] CMP Data Response: BRCS-001-002, Attachment 3 (CMP AMI Project Execution Plan 61510).
[38] AMI Program Governance Plan was owned by the AMI PMO and Program Team.
[39] CMP Data Response: BRCS-001-006, Attachment 1 (CMP AMI Governance).

highlighted in the governance document, the Company also maintained overall principles in the implementing of the AMI Program.[40]

Conclusion

We found through review of Program documents, interviews, and data responses that the Company executed the documented plan for the Program. The Company's documented processes included sufficient detail and covered the expected areas in order to provide proper guidance for the managerial oversight of the Program.

C. Program Reporting

In order to be assured that the AMI Program organization maintained effective awareness of the status of activities, costs, schedules, and related issues, Blue Ridge reviewed the reports used by the AMI Program team in its communication.

Within the reporting scope of the Company's AMI Program, CMP developed seven types of internal, eight types of external periodic reports to summarize the ongoing processes of the AMI Program and three updates to the Commission in presentation format.[41] A list of these internal and external reports that Blue Ridge reviewed is included in Appendix B.

CMP also provided the outlines of the regulatory filings that provided an update to costs and savings for the AMI Project from January 19, 2010, forward. The descriptions of these filings are included in Appendix C.

Recognizing that effective control of AMI Program costs required specific emphasis in maintaining consistency of cost and savings projections, Blue Ridge examined the status reporting of these cost items focusing on the information that was made available to the AMI Program Leadership Team.

The AMI Program Governance Plan defined 21 interdependent projects making up the AMI Program.[42] These Projects included areas such as Communications, AMI Meters Installation, and Cyber Security. The Project Teams assigned to these projects each tracked their progress against budget and schedule and provided a weekly status report to the PMO and summarized the project's progress against budget and schedule. According to the AMI Program Governance Plan,[43] the project status reports were supposed to include the following schedule items:

- Status of key project milestones and deliverables
- Planned vs. forecast or actual dates of key project milestones and deliverables
- Total number of active tasks previous and current period
- Number of tasks schedule to start/complete vs. actually started/completed current period
- Number of tasks schedule to start/complete next period

If any of the following conditions applied, the project manager would have provided an explanation and a recovery plan in an e-mail to the PMO accompanying their weekly status report.

- Any key milestone or deliverable is forecast more than one week late

[40] CMP Data Response: BRCS-001-015.
[41] CMP Data Response: BRCS-001-016.
[42] CMP Data Response: BRCS-001-006, Attachment 1.
[43] CMP Data Response: BRCS-001-006, Attachment 1.

- Any key milestone or deliverable actually occurs more than one week late
- Any tasks that were scheduled to start/complete within the current period did not start/complete

The project status report also included the following financial items:

- Project budget in dollars and hours
- Actual project dollars and hours spent to date
- Estimated dollars and hours required to complete the project
- Percent complete of project

From the information provided in the weekly status reports, the PMO would calculate the following earned value variables (in hours and dollars):

- Earned schedule = Budget * Percent Complete
- % Budget Burned = Actuals to Date / Budget
- Variance of earned schedule vs. burned schedule = % Complete - % Budget Burned
- Estimate at Completion = Actuals + Estimate to Complete
- Variance at Completion = Budget – Estimate at Completion
- Estimate at Completion Burn % = Estimate at Completion / Budget

If any of the following conditions (for hours or dollars) were identified by the PMO, it would ask the Project Manager via e-mail for an explanation and recovery plan, which would have been due to the PMO within 2 business days:

- Variance of earned schedule vs. burned schedule < -5%
- Estimate at completion burn % > 105%[44]

The weekly status reports were one important example of a number of reports identified in the Program Governance Plan to maintain effective control of the implementation. The Governance Plan also included monthly, semi-yearly, and annual budget reports:[45]

- Monthly – Every month, a comprehensive report of actual costs compared to budget for the project as a whole and for each sub-project was distributed to the Project Managers. It was a joint responsibility of the Project Managers and the Budget Management Office to review these reports and understand the costs and variances for their sub-project (employee hours, contractors, and materials).
- Semi-Yearly – Twice a year (and three times during the last year of the project), there was a formal process in which Project Managers assessed their budgets and projections for any material changes for the remainder of the year and project. Any changes were submitted to the Budget Management Office. Any potential variances were discussed at length and reviewed by the AMI Lead Team and AMI Steering Committee.
- Annually – The Investment Planning Group at Iberdrola USA compiles all budgets for the Company and ultimately submits for approval to the parent company, Iberdrola, S.A. This process begins in the third quarter of the prior year, and budgets go through multiple reviews and approvals.

While effective program management seeks to avoid cost overruns, they may occur. Effective management requires that a plan be in place to evaluate these potential overruns so as to ensure

[44] CMP Data Response: BRCS-001-006, Attachment 1, page 20-21.
[45] CMP Data Response: BRCS-001-019.

that justifiable reasons exist for their acceptance. In addition to the regular reporting, the AMI Program Governance Plan outlined the process criteria for the assessment of overruns in its program escalation matrix (below).

Table 3 Program Escalation Matrix[46]

	PSC	Program Leadership Team	Project/Team Leads
Budget	• Monitor approved program budget	• Approve individual project budgets within the defined program budget	• Monitor approved project budgets
Contracts	• Approve contracts of < \$1M • Recommend approval of contracts > \$1M to board	• Recommend contract approval to PSC	• Recommend project-specific contracts to Program Leadership Team
Change Requests	• Impact of > \$500K to budget • Impact of > 4 weeks to schedule • Discretion of Program Lead	• Impact of > \$500K to budget • Impact of > 4 weeks to schedule • Discretion of Program Lead	• No impact to budget or schedule
Issue Escalation	• Critical or Emergency Priority Issues	• High Priority Issues	• Low to Medium Priority Issues
Risk Escalation	• Program-level risks that have occurred or are deemed imminent • Potential program-level risks with High or Critical Threat Level	• Project-level risks with High or Critical Threat Level • Any project-level risks with cross-project dependencies • Project-level risks that exist across multiple projects	• Project-level risks with Low to Medium Threat Level that do not have cross-project dependencies

CMP's Governance Plan developed at the beginning of the AMI Program implementation set guidelines to ensure that program governance and budget control would be addressed with thorough and regulated attention. Blue Ridge found that the CMP Program lead team enhanced the approach to schedule adherence and budgeting control. The Team instituted an additional e-mail requirement, as mentioned above in discussion of the weekly status reports, to obtain variance explanations and recovery plans. According to CMP, budget and schedule variances were monitored through several avenues on an on-going basis. These monitoring efforts included the following:[47]

1. Weekly Status Reports incorporated discussions on all issues surrounding the individual projects, including any budgeting or scheduling issues.
2. Steering Committee meetings, typically held every two weeks, included any budgeting or scheduling issue that merited discussion at this level.
3. Every month, a comprehensive report of actuals compared to budget for the project as a whole and for each sub-project was distributed to the Project Managers. It was a joint responsibility of the Project Managers and the Budget Management Office to use these reports to review and understand the costs and variances for each sub-project.
4. Twice a year (and three times during the last year of the project), a formal process required Project Managers to assess their budgets and projections for any material changes for the remainder of the year and project. Any changes were submitted to the Budget Management

[46] CMP Data Response: BRCS-001-018.
[47] CMP Data Response: BRCS-008-008.

Office. Any potential variances were discussed at length and reviewed by the AMI Lead Team and AMI Steering Committee.

5. Any significant risks and associated mitigation plans causing cost or schedule issues were documented within the "Risk" section of the monthly DOE Reports.

Conclusion

Blue Ridge found that appropriate reporting was communicated at an effective frequency to maintain reasonable oversight of the Program implementation status. Blue Ridge reviewed selected reports for content, identification of issues, compliance with Company policies and procedures, DOE requirements, and active participation by the AMI Project team. We found that the reports were in compliance with Company and DOE requirements and that the AMI Program team members were active participants in the process.

The Governance Plan provided adequate guidance for reasonable and prudent control of budget and cost. The reports distributed during the Program implementation and the information that was communicated were sufficient to reasonably control costs. While the Governance Plan anticipated a more formal, less pro-active process, by immediately reporting variance explanations along with discussion of mitigation strategies, the PMO as well as all Program participants were kept apprised of budget and cost activity without the more time-consuming delays and less availability involved in the email exchange first envisioned.

D. Outsourcing Plans

Outsourcing of certain AMI Program activities required proper oversight to ensure that cost and schedule concerns were managed properly. In December 2010, the Company provided an outsourcing/vendor selection plan[48] to the AMI Program Steering Committee. The plan was intended to provide a high-level overview of the services and systems required for the program as well as an overview of the steps from RFP to contract award. Approval for vendors and contracts greater than $500,000 required review from the Steering Committee and approval for contracts greater than $1,000,000 required review by Iberdrola and the Iberdrola USA Board.

The Company provided the Iberdrola USA's Procurement Services Policy Manual, which was the version of the procurement policy in place from 2004 to July 2010.[49] The manual contains sections that discuss the following: (1) General Policies and Procedures, (2) Bid Process, (3) Purchase Order & Contract Preparation/Issuance, (4) Purchasing Card Policy & Procedure, (5) Contract Administration & Monitoring Performance, and (6) Follow Up & Special Purchases.[50] Blue Ridge examined the manual and found that it provided adequate direction for procurement services.

Within the duration of the AMI Program Implementation, the Company issued 8 RFPs for the following: (1) Electrician, (2) Energy Portal, (3) Meter Asset Management System, (4) Network Deployment and Troubleshooting, (5) Outage Management and GIS, (6) Settlement System, (7) System Integrator, and (8) Web Redesign Staff Augmentation.[51] The Company stated that the intended recipients of these RFPs were generally selected based on industry knowledge and the Procurement organization's experience. In the case of the AMI RFPs, an RFI was developed and the

[48] CMP Data Response: BRCS-001-021.
[49] CMP Data Response: BRCS-001-022 CONFIDENTIAL.
[50] CMP Data Response: BRCS-001-022 Attachments 1 through 6 CONFIDENTIAL.
[51] CMP Data Response: BRCS-001-023.

results of the RFI supported the list of intended recipients.[52] The Company then provided the Steering Committee with two categories of information for each vendor in the selection process: (1) the vendor scoring information and/or (2) the vendor recommendations, which provides an overview of the analysis conducted in the selection process.[53]

To describe the processes used by the Company to oversee work product of the vendors/contractors on the AMI Program, the Company provided the Trilliant AMI System agreement[54] (a governance plan developed specifically for each individual vendor). Blue Ridge examined the agreement and concluded that it provided adequate oversight specification by which to manage the outsourced activities properly.[55]

The oversight of these outside vendors followed the AMI Program governance processes including status reporting, meetings, issues tracking, and risk management. In the case of Trilliant, the largest vendor for the program, the Project teams met daily to review program status. Trilliant provided weekly status reports. There were bi-weekly meetings with CMP project personnel to ensure clear communication on status and issues. Contractually, the majority of the systems that were implemented were milestone driven with payments held until the milestone deliverables were met. In addition to the governance and contractual oversight, the company followed their standard IT process[56] for ensuring system change requests and tracking to ensure that any new system changes were tracked and approved before moving into production. Requiring a clear rationale and detailed request from vendors to approve any system changes.[57]

Conclusion

Blue Ridge reviewed the Company's original outsourcing selection plan; the vendor and contractor procurement procedures; and the bid packages for the AMI Program system contractors, consultants, and vendors. Based on the consistency with internal requirements and thoroughness of data required, Blue Ridge determined that the plan and procedures were reasonable. Furthermore, the level of oversight that the Company provided for outsourced contractors appeared adequate.

Additionally, from the information provided, Blue Ridge found that the Company's decisions regarding outsourcing authorizations using criteria corresponding to each of the vendor contract provisions were reasonable.

E. Scheduling and Scope Changes

In any large-scale project such as AMI deployment, scheduling and scope changes almost always impact cost. In order to assess the progress reports for impacts to the AMI program's schedule and related changes in scope, plan, and implementation, Blue Ridge requested and received the master schedules and timelines of the events and timing of the AMI Project. As part of that response, the Company stated that in June 2010, the Company finalized the AMI Project Execution Plan (PEP), a preliminary schedule and timeline, and presented it as part of the US

[52] CMP Data Response: BRCS-001-023.
[53] CMP Data Response: BRCS-001-024 CONFIDENTIAL.
[54] CMP Data Response: BRCS-001-027 Attachment 2 (Final – Exhibit M Project Governance-Management (W1840528).pdf).
[55] CMP Data Response: BRCS-001-029 Attachment 2, page 17 (2009-8-6 Central Maine Power Project Plan – Final_Confidential.doc) CONFIDENTIAL.
[56] CMP Data Response: BRCS-001-027 Attachment 2 (EEQIP Standards.doc).
[57] CMP Data Response: BRCS-001-027.

Department of Energy (DOE) Smart Grid Investment grant requirements.[58] During the AMI Program, CMP provided monthly status updates on the major milestones to the DOE, weekly reviews of the Integrated Project Plan[59] by the team, and weekly project status reports with program milestone statuses to the team and Executive Steering Committee.[60]

In August 2010, the Company presented a high-level AMI Program schedule to the Commission and Staff. After the AMI Program was completed and fully implemented in June 2013, the Company gave a presentation to the DOE, which showed that the AMI Program key schedule dates aligned closely with the original timelines and milestones presented to DOE in August of 2010.[61] There were various scope changes throughout the timeline of the AMI program, but these did not affect the overall initial timeline.[62]

Conclusion

Blue Ridge reviewed the Company's master schedule, timeline, various progress reports, including the monthly status updates to the DOE, the weekly reviews of the Integrated Project Plan, and the weekly status reports to the team and Steering Committee, and found that both the management of the schedule and the completion of the activities were timely, cost effective, and reasonable.

F. OVERALL CONCLUSION FOR AMI PROGRAM MANAGERIAL OVERSIGHT

Blue Ridge's review of the AMI Program Managerial Oversight revealed that CMP developed a reasonable and adequate organization and plan to effectively manage and implement the AMI Program. The AMI Program Team Organization was staffed with well-qualified and experienced Company personnel and received sufficient senior management involvement. Policies and procedures were reasonable and were followed by the Company or were more rigorous than the procedures required. Reporting provided adequate and reasonable communication to keep all levels of AMI Program management apprised of cost and schedule concerns, ensuring opportunity to address them in a timely manner as needed. All documented processes included sufficient detail and covered expected areas to provide guidance for the proper oversight of the AMI Program.

Therefore, Blue Ridge found that the Company did employ reasonable and prudent practices in its management of the project and has acted in accordance with reasonable and prudent practices to ensure reasonable control of the Program implementation.

[58] CMP Data Response: BRCS-001-002 Attachment 3 (CMP AMI Project Execution Plan_61510.pdf).
[59] The Integrated Project Plan was the basis of the DOE PEP schedule.
[60] CMP Data Response: BRCS-001-002.
[61] CMP Data Response: BRCS-001-002.
[62] CMP Data Response: BRCS-001-028.

3. AMI PROGRAM BUDGET AND COST

In its Order requesting this management audit, the Commission ordered that the audit review the realized and expected savings of CMP's AMI Program. Specifically, the Commission stated that the auditor should determine, *"whether CMP has appropriately and accurately identified the savings realized to date from the AMI project and provided reasonable estimates of these savings on a going-forward basis."*

To answer this question, Blue Ridge reviewed how the Company is evaluating and proving the realized savings. In addition, Blue Ridge reviewed the underlying assumptions associated with the Company's projections for on-going operational and avoided costs savings. The actual savings achieved has been a concern of the Commission, and this section addresses that concern.

The Company originally estimated that the capital cost to complete the AMI Program would be $163.8 million. This amount was later revised to include the net book value ("NBV") of existing legacy analog/mechanical meters which increased the total program costs by $27.9 million to $191.7 million.[63] The NBV of the legacy meters represents the un-depreciated value of the legacy meters (not recovered through depreciation) that were replaced with AMI meters. With the grant from the ARRA, the DOE contributed $95.9 million to the project, which included 50% of the NBV of the legacy meters.

The original cost of the project (as of January 2010) included the following components:

Table 4 Component Original Costs[64]

Components	Original Costs (in Millions)
AMI Meters	$ 78.40
IT	$ 31.60
Meter and Network Installation	$ 20.60
AMI System Network	$ 9.60
Project Management	$ 7.10
MDMS	$ 3.50
Research	$ 1.50[65]
Contingency	$ 11.50
Total	$163.80

In support of the original project cost, CMP provided detailed schedules that identified how the costs were derived and the various cost components. Blue Ridge reviewed those detailed cost schedules to ascertain that the cost of the project was adequately supported and explained.

Certain cost overruns (provided later in this section) were identified during the course of the project and the actual 2012 total project cost was reported as $167.18 million, which created a variance of only $3.38 million.[66] That variance is about 2% of the entire Program implementation.

---

[63] MPUC Docket No. 2007-215(ii), February 25, 2010.
[64] CMP Data Response: BRCS 002-009, attachment 1, pages 1-2.
[65] Determined to be O&M.
[66] CMP Data Response: BRCS 002-009, attachment 1, page 2.

As shown in the table above, the AMI Program costs included $11.5 million for project contingencies. The inclusion of a contingency in a large project is normal, and, based on experience, Blue Ridge considers a normal range to be anywhere from 5% to 10%. The AMI project contingency was approximately 7.5%, which is within the band of reasonableness.

A. Actual Costs

The Company expected to spend approximately $1.97 million per year (average) or $7.9 million in Operations and Maintenance (O&M) costs for the period 2009-2012 and then approximately $2.15 million per year (average) or $40.9 million for the post-implementation period 2013-2031. These O&M costs are in the following categories.

Table 5 Operations and Maintenance Cost Categories[67]

	2009-2012 (Deployment)	2013-2031 (Post-Deployment)
Customer Communications	$ 319,346	$ 0
NDC Communications Costs	$ 240,000	$ 1,824,000
Computer Hardware Maintenance	$ 2,071,558	$ 8,278,142
Head End Software Maintenance	$ 1,302,000	$ 8,246,000
MDMS Software Maintenance	$ 742,500	$ 4,702,500
WAN Communications Costs	$ 198,450	$ 1,675,800
Operations Labor	$ 947,659	$16,203,480
Add on Software Maintenance	$ 2,059,313	$ 0
Total	**$ 7,880,826**	**$40,929,922**

The Company identified certain cost overruns throughout the AMI Program:[68]

- Additional Repeaters[69] needed for Opt-Out Program – Given that the Opt-Out Program was mandated by the MPUC and revenues from the Opt-Out fees were collected to offset the additional costs, there was no mitigation implemented for this unanticipated item.[70]
- Additional Meters Purchased for Inventory – Meter inventory would need to be purchased eventually but advancing the purchase before the contract expired (in March 2013) allowed for a 50% DOE match to offset the costs. In total dollars, the amount of this meter purchase was $1.7M, and at 50% DOE matching offset, $850,000. Based upon the longer-term savings opportunity, the AMI Steering Committee approved this additional expenditure at that time.[71] [72]
- Use of Contingency - Because the network was a critical part of the AMI System, use of the contingency to fund overruns was utilized but also constantly monitored by the AMI Lead Team and AMI Steering Committee. CMP always considered it a priority and a goal to ensure that the total AMI Project Costs be at or below the total budget, and it was understood that there would be some slight variances within certain sub-projects that offset each other.

---

[67] CMP Data Response: BRCS 001-013, Attachment 1.
[68] CMP Data Response: BRCS-001-028.
[69] Repeaters are equipment that relay a signal beyond an initial collecting point.
[70] CMP Data Response: BRCS-001-019.
[71] CMP Data Response: BRCS-001-019.
[72] CMP Data Response: BRCS-001-017.

Managing to the total project budget was always a Company goal of the Program.[73]

- O&M portion of Network Installation – O&M spending for the AMI Project was under-budget for 2010 and 2011, over-budget for 2012, but under-budget for all three years total.

Table 6 O&M Actual Results, Original Budgets, and Variances

In Thousands	2010	2011	2012	Total
Actual	$2,439	$3,296	$4,137	$9,872
Plan	2,817	4,382	3,047	$10,246
Variance Over/(Under)	($378)	($1,086)	$1,090	($374)

The Company indicated that the 2012 overrun of $1.1 million was largely attributable to the O&M portion of the network device installation. This overrun was discussed and approved by the AMI Program Leadership Team based upon critical need of the network functionality. Each network device installation was reviewed and approved for economic viability. For example, if a network device did not serve more than two meters, installation was not approved.[74] [75]

- O&M Telecommunication Costs – The overrun in telecommunication costs directly correlates to the number of networks devices installed. Efforts to mitigate these costs through optimization of network installation continues.[76]

Conclusion

Based on Blue Ridge's review of initial costs, changes to cost over the duration of Program implementation, and the resultant cost of the project, we determined that (1) the cost of the project was adequately supported and (2) the resultant total cost appears reasonably in line with initial estimates.

B. Contractor Scope Changes

The Company originally outsourced a total of $133.3 million for the AMI Program. Due to scope changes various vendors asked for change orders amounting to $7.9 million over the period of the program. The following chart lists outsourced contract amounts.

Table 7 Outsourced Contract Amounts[77]

Vendor	Original Contract Amount	Change Orders	Total Contract
Aclara	$1,217,000		$1,217,000
Advent Design	$586,000		$586,000
Black & Veatch	$12,790,000		$12,790,000
Brooks Utility Services	$800,000		$800,000
Elec. Systems of Maine	$700,000		$700,000

[73] CMP Data Response: BRCS-001-019.
[74] CMP Data Response: BRCS-001-019.
[75] CMP Data Response: BRCS-001-017.
[76] CMP Data Response: BRCS-001-019.
[77] CMP Data Response: BRCS-001-026, 028, and WP – Combining 001-026,028 and 025.xlsx.

Vendor	Original Contract Amount	Change Orders	Total Contract
EMC	$3,700,000		$3,700,000
Erbridge	$450,000		$450,000
ESRI	$2,353,000		$2,353,000
FSC Group	$979,495		$979,495
Itron	$3,571,000	$489,000	$4,060,000
JF2 LLC (On Target)	$375,000	$200,000	$575,000
Mancini Electric	$700,000		$700,000
Oracle	$328,302		$328,302
Pierce Atwood	$1,050,830		$1,050,830
Quaker Lane Associates	$1,100,000		$1,100,000
Red Hat	$592,000		$592,000
Tendril	$1,337,974	$(40,000)	$1,337,974
Tilson Government Services	$2,520,000	$1,500,000	$4,020,000
Trilliant	$85,446,003	$3,700,000	$89,146,003
VSI	$10,720,000	$2,067,536	$12,787,536
Wiswell	$500,000		$500,000
Zerochaos	$1,525,317		$1,525,317
GE, Landis + Gyr			$ 0
Computer Associates, SHI International			
CS Business Systems Inc			$ 0
Grand Total	$133,341,921	$7,916,536	**$**141,258,457

A total of twenty-one instances of contractor scope changes were approved during the AMI Program.78 A summary of the major changes follows:

1. Itron – Designs, manufactures, markets, installs and services systems and fixed communication networks for automatic and electronic meter reading
    a. Itron_CMP_Tendril Interface Project - $99,000 on 3/12/12

        Description: Meter reading export customization from MDM to Tendril Energy Manager Portal

        Reason: The customization export work supported the translation of data between the MDM and Tendril's Energy Manager Portal. Without this customization, the Energy Portal would have been delayed.

    b. Web Services Translator - $208,000 on 6/5/11

        Description: Custom build web service interfaces between MDM, CAD, and Head End System to enable remote service orders

        Reason: Implement an automated remote service order process to reduce field resources and enhance business efficiencies.

    c. Settlement Adapter - $161,000 on 10/30/12

[78] CMP Data Response: BRCS-001-028 Attachment 1 (AMI Program Scope Change by Vendor).

Description: MDM custom high-speed extract of interval data for all active accounts for daily loading into the Aclara settlement system

Reason: To provide hourly interval data to meet the New England ISO requirement for 100% settlement.

d. SOW Phase 2 Extension - $21,000 on 3/14/11

Description: Extension of Itron services in support of MMCC/CSR go-live

Reason: The extension of the services to support the extended go-live of MMCC/CSR Portal

2. JF2 LLC/On Target[79] – Provides locating, metering, smart grid, telecommunication, cable and private customers throughout the Northeast

   a. On Target Change Order for Inspectors - $200,000 on 5/17/12

   Description: Extension of network inspectors for 4 months; two employees @ $62/hr for 7 additional weeks plus contingency for unexpected overtime.

   Reason: CMP requires an extension of the services with On Target due to the increase in network devices being installed. An additional 1000 repeaters have been added. The network site selection is based on Trilliant's network design changes. The network site selection work was expected to be completed by April 2012, but the work has extended to August 2012. The extension of services is due to the increase in network sites requiring selection and inspection and the extended schedule.

3. Tendril[80] – Web Portal Software

   a. Tendril Change Order # 1 – ($40,000) on 5/14/12

   Description: The change request agrees to recover of cost incurred by Itron to translate the export between the MDM and the Tendril portal.

   Reason: See Itron_CMP_Tendril interface project (above).

4. Tilson[81] – IT Services

   a. Tilson Amendment 1 - $1.5 million on 3/2/12

   Description: The amendment includes the extension of service for network design, siting and troubleshooting.

   Reason: The additional scope of work was required due to the additional network devices being installed.

5. Trilliant[82] – Smart Grid Innovator

   a. Amendment 1 - $1.0 million on 7/15/11

   Description: System Agreement provided for an increase in network devices and a change in network device type from Extenders to Extender Bridges. The amendment

---

[79] CMP Data Response: BRCS-001-028 Attachment 1 (AMI Program Scope Change by Vendor).
[80] CMP Data Response: BRCS-001-028 Attachment 1 (AMI Program Scope Change by Vendor).
[81] CMP Data Response: BRCS-001-028 Attachment 1 (AMI Program Scope Change by Vendor).
[82] CMP Data Response: BRCS-001-028 Attachment 1 (AMI Program Scope Change by Vendor).

initiated the route performance schedule and provided additional time for the second stage of performance levels. The amendment addressed the responsibility for and costs to fix the meter communication modules.

Reason: The amendment addressed the changes in the network design. The incremental cost for the network increase was $1 million. The amendment also triggered the timing to initiate the review of performance metrics for liquidated damages. It was important for CMP to trigger the performance metrics to ensure Trilliant was meeting the schedule and timeline. CMP also wanted to memorialize Trilliant's responsibility for the work required to address the meter communications issues.[83]

b. Amendment 2 - $2.7 million on 2/2/12

Description: Amendment 2 to the AMI System Agreement finalized the total number of network hardware devices required for the network redesign. It defined a section of the service area defined as ultra remote that represented ~6k meters that would be excluded from the performance metrics. It also provided an interim milestone for the release of the Letter of Credit.

Reason: Caps on network device hardware and necessary core sites were negotiated to limit CMP's exposure for increased capital and O&M costs. Interim network designs had forecasted the number of repeaters to be significantly higher than originally agreed. The potential exposure on the network was estimated at more than $3 million above the agreed terms. The meters were 96% deployed and 83% of the network was in place at the time this amendment was negotiated. It was important to continue to move the program forward while seeking to minimize capital and O&M exposure.[84]

c. Conditional Agreement - $0 on 10/31/12

Description: The conditional agreement defined the remaining contractual obligations for Trilliant to achieve the final stages for contract close out. CMP released Trilliant from its route level performance metrics but maintained system level performance metrics. In exchange, Trilliant provided $250k worth of additional hardware to complete the network design and agreed to provide an ultra remote solution.

Reason: The conditional agreement was negotiated at the point when the network performance was meeting the overall performance levels that supported the target goal for operational efficiency. CMP wanted to control the final network tuning design in order to ensure a balance of economic deployment and required performance levels. Trilliant provided additional hardware and maintained their commitment to ensure key functionality delivery

6. VSI (Grid One)[85] – AMI/AMR Deployments, Implementing Demand Response & Energy Management Programs, Contracted Meter Reading, Field Service Work, and Call Center Operations $2,067,536

   a. Change Requests

[83] CMP Data Response: BRCS-001-028 Attachment 1 (AMI Program Scope Change by Vendor).
[84] CMP Data Response: BRCS-001-028 Attachment 1 (AMI Program Scope Change by Vendor).
[85] CMP Data Response: BRCS-001-028 Attachment 1 (AMI Program Scope Change by Vendor).

1) $102,060 - VSI requested a change order to recover unanticipated operating costs due to the delay beyond the established start date of August 30, 2010. This delay was caused by unavailability of meters due to issues found during meter testing. This delay from August 30, 2010 through September 23, 2010 is 18 business days as a daily cost impact is $5670.00. This cost was exclusive of added training and hiring costs associated with the loss of personnel or the need to retrain due to downtime.

2) $9,540 - Delays in the start date due to events created an impact to the schedule and impacted VSI's ability to recover retraining costs due to attrition. Technicians hired for the 8/30/10 deployment were laid off by VSI and have been rehired and retrained and have completed additional refresher training, due to the delay.

3) $242,823 - A significant change in scope impacting ability to meet target installation rates has been created by technology and material availability issues. The restrictions caused a need to work areas not planned during winter months and delay installing in areas where VSI could have achieved a balanced productivity. VSI supported CMP's needs through these conditions with a rate increase to offset the impacts of the inefficiencies. These restrictions included but were not limited to; areas originally scheduled to meet productivity during winter months have been made unavailable causing need to work in remote low density areas incurring added travel times not in original deployment plans. Meter Forms/Classes are unavailable during initial pass, causing need to revisit areas to install same when available, adding increased labor and travel expense. Ability to create a balance to maintain a productive level when blackout in effect in a given area has been eliminated.[86]

4) $197,087 - VSI requested a change order to revise unit rates for single phase and network meters from $12.50 to $15.88 due to significant change in scope. This change request applied to all meters installed at the current unit rate of $12.50 between the time period of February 28, 2011 to April 30,2011

    a. $101,363 - VSI requested a change order to revise unit rates for single phase and network meters from $13.88 to $15.88 due to significant change in scope. This change request applied to all meters installed at the current unit rate of $13.88 between the time periods of July 4, 2011 to August 20, 2011.[87]

5) $737,727 - VSI requested a change order that required an increase in all unit rates by 11%. This change was effective May 1, 2011 through the remainder of the project. This change order was in response to the request by CMP to increase staffing to 75 installers.

6) $13,250 - VSI requested a change order for IT development efforts and Multiple Attempt unit rate application for CMPs "Change of Heart" accounts. There were roughly 8,000 accounts that have Opted Out of having a Smart Meter; a subset of these accounts will be identified as the "Change of Heart" accounts. This change was effective June 15th, 2011 through the remainder of the CMP /VSI AMI project.

---

[86] CMP Data Response: BRCS-001-028 Attachment 1 (AMI Program Scope Change by Vendor).
[87] CMP Data Response: BRCS-001-028 Attachment 1 (AMI Program Scope Change by Vendor).

7) $220,000 - Grid One Installer Retention Bonus ($1,000 Year end and $1,500 project end bonus). This was to ensure we met the meter installation goals and program timelines
8) $100,000 - Year End Target Bonus (516,000 Installs) was an incentive to meet yearend target goals and program timelines.

b. *AMI Firmware Upgrade*

1) $285,214 - VSI resources supported infield firmware upgrades of Trilliant's communications module in the meter. This cost was reimbursed by Trilliant - PO# 10104253.

c. *HSP* (Meter Seal) Replacement

1) $58,472 - CMP had faulty meter seals that were delivered and installed. VSI helped support replacing the faulty meter seals - PO# 10104255.

Blue Ridge's review of the contractor scope changes showed that the Company reviewed, justified, and controlled scope changes made by the various vendors and contractors on the project.. Blue Ridged calculated that the total impact of the scope changes on total project costs was less than 6%. We believe that, given the magnitude of the AMI program, this change to contractor costs does not reflect unreasonable change, especially considering the Company's procedural control and oversight.

C. COST/SAVINGS DIFFERENCE – AUGUST 2012 TO MARCH 2013

In the Order Initiating the AMI Management Audit dated June 17, 2013, the Commission identified a significant variance between the January 2010 estimated net savings and the adjusted projection of the Company's March 2013 filing. This variance was in part the reason for the Commission ordering this audit.

The January 2010 cost-benefit estimate contained savings for 2009 through 2013 using an annual savings based on 2006. The estimate also contained savings for 2014 through 2032 using an annual savings based on 2008.[88] The Company adjusted these annual savings amounts (base year 2006 of $7.55 million and base year 2008 of $7.95 million) for the August 2012 filing. In that filing, the 2006 base year savings changed to $7.36 million, while the 2008 base year savings changed to $7.74 million.[89] Blue Ridge issued a data request to the Company to reconcile this August 2012 net savings amount with the March 2013 filing which showed a net cost rather than net savings.

In response to Blue Ridge's data request, the Company noted that the difference between the August 2012 filing and the March 2013 filing was about $82 million. CMP indicated that these two filings were not developed by the same method and it was therefore difficult for an apples-to-apples comparison.[90]

The Company provided an explanation of differences between the two filings. The differences were as follows:

August 2012 Filing:

[88] CMP Data Response: BRCS-001-013, attachments 6 and 7.
[89] CMP Data Response: BRCS-001-011, attachments 25 and 26.
[90] CMP Data Response: BRCS-002-011 Supplemental.

1. Filing represented a cost-benefit analysis designed to provide a 20-year forecast of savings net of costs associated with implementation of the AMI Program
2. Analysis was performed independent of the level of expenses embedded in the Company's current tariffs
3. A portion of the values contained in the 2012 filing represented savings associated with future costs that are avoided but which were not embedded CMP's 2012 tariffs

March 2013 Filing:

1. Filing presented a one-year cost of service revenue requirement associated with the AMI project for costs and savings incremental to those provided for in rates
2. Purpose was to identify the incremental impact to existing rates effective July 1, 2013, for a one-year period
3. Filing was not calculated to determine the value of the project but rather to determine the rate impact beginning July 1, 2013
4. Filing envisioned that the costs and savings associated with AMI after this one-year period would be incorporated into the Company's new distribution rates effective July 1, 2014

Because of the "apples-to-oranges" relationship of the two filings, the Company provided a detailed analysis of the $82 million variance. CMP identified three key differences between the filings that were responsible for the variance:

1. <u>Difference in Forecast Periods</u>: The Company's August 2012 filing provided a cost-benefit analysis of savings net of costs over a period of twenty years. The March 2013 filing represented a one-year cost of service revenue requirement associated with the costs and savings incremental for AMI.

   At Staff's request, the Company simply grew this one-year forecast using general inflation factors (1% for all costs and 3% for all savings) for a 20-year period. The resulting projection did not reflect any changes, aside from inflation, in the costs associated with the AMI project.

2. <u>Differences in Purpose</u>: As outlined above, the level of costs currently in the Company's tariffs was not a consideration in the August 2012 filing, while they were a critical component of the March 2013 filing, as it sought to determine the appropriate level of recovery associated with the incremental impact of AMI. As a result, there are legitimate savings that were generated by the implementation that were captured in the August 2012 filing and excluded from March 2013 simply because they were associated with costs that were not embedded in rates.

3. <u>New Information</u>: Over the time that elapsed between the two filings, certain updates were identified that needed to be made to more accurately reflect the costs and savings associated with the AMI project.

The following table displays a summary of the variance broken down by costs and categorized by the three key differences noted above.

Table 8: August 2012 to March 2013 Variance Analysis[91]

		Differences in Forecast Period	Differences in Purpose	New Information	Total Variance
1	Network Maintenance Cost on Towers	$23.9	$0	$(0.8)	$23.1
2	Customer Relations Center Savings	0	17.5	0	17.5
3	Transportation Savings	0	11.9	5.6	17.5
4	Benefit Savings	16.4	0	0	16.4
5	Infrastructure Costs	10.2	0	0.9	11.1
6	Cyber Security Costs	7.1	0	0.3	7.4
7	Operations Labor Costs	0	(23.8)	0	(23.8)
8	Subtotal	$57.6	$5.6	$6.0	$69.2
9	All Other				12.8
10	**Total Variance**	**$57.6**	**$5.6**	**$6.0**	**$82.0**

CMP provided explanations for each of the line items in the above table:[92]

1. Network & Maintenance Costs on Towers – $23.1M: The Company's August 2012 analysis assumed that certain Network Costs on Towers would not reoccur annually beyond 2014. The twenty-year projection associated with the March 2013 filing assumed that the one-year expenses would grow 1% annually for the twenty-year projection. This difference in the estimated costs resulted in a $20.7M variance. The Company believes that these expenses will continue beyond the current Rate Year (7/1/13 – 6/30/14), but believes the costs will decline over time as its experience with the AMI System grows.

   In the August 2012 analysis, Tower Crew Maintenance Costs were forecasted to level off in 2014 (the year the after project was completed), and remain constant with no escalation, for the remaining years of the project. The twenty-year projection associated with the March 2013 filing assumed that these expenses would grow 1% annually. This difference in the estimated future costs resulted in a $3.2M variance.

2. Customer Relations Center Savings – $17.5M: The Company's August 2012 analysis included avoided costs that would have occurred but for the AMI project. As observed above, the Company's intent in March 2013 was to provide only a one-year rate impact of AMI (including incremental savings).

3. Transportation Savings – $17.5M: In its March 2013 filing, the Company estimated one-year transportation savings, consistent with the ARP2008 price change mechanism, based on the level of costs embedded in rates, which was 2008 values grown by inflation less a productivity offset. The twenty-year projection of the one-year savings in the March 2013 filing assumed that these saving would grow 3% annually.

   The August 2012 filing was consistent with the March 2013 approach through 2013. Upon the conclusion of ARP2008 in 2014, the August 2012 filing began calculating transportation savings by applying an inflation factor to actual costs, regardless of levels embedded in rates, to determine transportation savings. Since actual transportation costs grew at levels in excess of inflation less productivity through 2013, the August 2012 filing

[91] CMP Data Response: BRCS-002-011 Supplemental Attachment 1.
[92] CMP Data Response: BRCS-002-011 Supplemental.

began recognizing a significant increase in savings beginning in 2014, resulting in a $11.9M variance.

The remainder of the variance is associated with the return on investment (ROI) on vehicles utilized for meter reading in its August 2012 filing. In the March 2013 filing, the Company did not identify any reduction in vehicles (and therefore no reduction in the ROI on vehicles) from the level embedded in rates, so no savings were incorporated into the cost of service revenue requirement.

4. Benefit Savings – $16.4M: In the March 2013 filing, the Company estimated benefit savings, consistent with the ARP2008 price change mechanism, based on the level of costs embedded in rates, which was 2008 values grown by inflation less a productivity offset. This calculation involved multiplying the percentage of overall Company benefits divided by total Company payroll times the payroll savings associated with the AMI implementation forecasted to have occurred in the July 1, 2013 – June 30, 2014 period. The twenty-year projection of the one-year savings in the March 2013 filing assumed that these savings would grow 3% annually.

   The August 2012 filing calculated benefit savings consistent with the March approach through 2013. Upon the conclusion of ARP2008 in 2014, the August 2012 filing began growing avoided benefit costs for both the reduction in employees and an accelerated growth in expected benefit costs. As a result, the benefit percentage grew over the 20 year period because the Company anticipates health care benefits will grow at a faster pace than inflation. Forecasted benefit savings in the August 2012 forecast went from a 3.3% increase in 2013, to 11.4% in 2014, and then grew from 4.5% to 5.5% for the remainder of the twenty-year forecast period.

   The variance in growth rate assumptions in the March 2013 and August 2012 filings resulted in a substantial variance in the forecasted benefit savings, particularly in the final ten years of the twenty-year forecast period due to the effects of compounding. The Company classifies this difference being related to a difference in the forecast periods because the March 2013 forecast was never intended to determine savings outside of its one-year forecast period. While these higher level of avoided benefit costs are likely to be realized, they were not embedded in rates during the one-year forecast period.

5. Infrastructure Costs – $11.1M: In the March 2013 filing, the twenty-year projection of mainframe maintenance costs grew the forecasted one-year expenses at 1% annually. The August 2012 filing only expected these costs to continue through 2015, as the mainframe will be replaced in 2016. This resulted in a $6.6M variance.

   The August 2012 analysis forecasted that certain infrastructure costs would not reoccur annually beyond 2014. The March 2013 twenty-year projection grew these forecasted one-year expenses at 1% annually. This results in a $3.6M variance as the result of differences in the forecast periods.

6. Cyber Security Costs – $7.4M: $0.3M in one-year costs associated with a vulnerability assessment as part of a cyber security plan were incorporated into the March 2013 filing and grown 1% annually for the twenty-year projection. The August 2012 analysis did not include these expenses. While the one-year costs are appropriately included in the March 2013, the Company acknowledges that these costs are not expected to reoccur annually.

7. Operations Labor Costs – ($23.8M): The August 2012 filing included incremental positions associated with the support of AMI. The Company excluded these costs in the March 2013

filing as the majority of these positions were filled with internal transfers that did not result in expenses incremental to the level provided for in rates in ARP2008

The Company has stated that the updated cost-benefit analysis for the AMI Program as filed in August 2012 is the last one it has completed. CMP does not have plans to redo this assessment, citing the growing list of assumptions associated with the numerous and varied impacts of the Program incorporated into normal operations of the Company.

CMP has indicated, however, that while preparing this reconciliation, the Company's review identified a number of attributes of the Program that it anticipates may result in additional customer savings and benefits over the next twenty years. Although as time goes by it becomes increasingly difficult to delineate the impacts of AMI from other corporate initiatives, CMP anticipates continuing to identify and capitalize on such opportunities. Whether such efficiencies can be identified as directly attributed to AMI, customers will realize their resulting savings and benefits as CMP's transmission and distribution rates are rebased during future rate case proceedings.

D. Overall Conclusion for AMI Program Budget and Cost

Blue Ridge's review of the AMI Program Budget and Cost revealed that the Company's cost of the project was detailed and supported. Contractor costs did increase, but only to a level of less than 6%. Changes in other costs that occurred during the project were adequately explained. The final costs were reasonable in relationship to the estimates.

Based on explanations provided in interviews, Blue Ridge's review of the detailed support of Company documents regarding the August 2012 to March 2013 comparison as summarized above, and the other documents providing savings and cost data received as responses to data requests, Blue Ridge believes the Company to have satisfactorily explained the variance between the net savings of the cost-benefit analysis method in filings from January 2010 to August 2012 and the cost and savings reported in the March 2013 filing.

4. AMI PROGRAM CAPABILITIES

In this area, Blue Ridge reviewed and addressed the Commission's concern of whether the promised capabilities of the Company's AMI Program were actually installed. This effort entails understanding what capabilities were committed to by CMP and whether what was installed met the expectations of the Commission and Staff. We also reviewed the information, which CMP used to keep the Commission and Staff apprised of the AMI program capabilities implementation.

Blue Ridge issued several data requests and conducted several interviews to further our understanding and to help us determine where the ambiguity and/or inconsistency exists between the Company and the Commission's (and Staff's) understanding of promised and delivered capabilities.

As proposed to and approved by the Commission in its February 2010 Order, CMP's AMI Program would include state of the art AMI meters and their related systems with certain capabilities, including detailed customer usage measurement, customer usage data storage, automated and remote meter reading, and wireless communication to and from the meter. In its Order approving AMI, the Commission based its decision on certain capabilities that CMP stated would be a part of the implemented AMI Program. These capabilities included the following:

- Measuring and storing load on an hourly (or less) interval basis
- Measuring and storing the TOU peak demands of each customer as necessary for billing and settling ICAP tags as well as each customer's daily peak demand
- Back office and billing systems capable of billing, both T&D and supply, on a TOU basis
- Remote disconnections and reconnections
- Reliability poll individual meters to evaluate outages and must include an outage tracking system
- Monitoring and measuring voltage variances
- Accommodate "value added" systems and devices (e.g., in-home displays, load control devices)

Based on its concern that the implemented AMI Program lacked these capabilities, the Commission ordered that this audit determine *"whether CMP has employed prudent and reasonable management to ensure that the AMI and related systems have the capabilities envisioned by the Commission at the time that the AMI system was approved."*

Blue Ridge's workplan included steps to review and determine whether the Company had met the Commission's expectations for these capabilities and whether CMP employed reasonable and prudent management practices to ensure the envisioned capabilities were installed.

A. AMI CAPABILITIES ENVISIONED

In July, 2009, the Commission issued an order granting approval of CMP's request to pursue its AMI Program. However, as part of that Order, the Commission made its final approval subject to CMP receiving a substantial Department of Energy (DOE) grant award. This Order, therefore, gave general approval to the concept of AMI and permission for the Company to continue to pursue AMI opportunities. The Commission's final approval would be predicated on CMP obtaining the DOE Grant. CMP was able to obtain the DOE award and subsequently filed testimony in January 2010 requesting authorization to implement its AMI Program. In addition, CMP proffered that its implementation would include certain capabilities and company and customer benefits. These benefits were included under three broad categories:[93]

- Provide customer electricity usage information via a Web portal and supporting real-time electricity usage information via a home area network (HAN).
- Support dynamic pricing and enhance CMP's restoration of service after major storms.
- Include sufficient bandwidth to support applications beyond AMI that enable future Smart Grid activities, including monitoring of power quality, charging and discharging of plug-in electric vehicles, and further automation of the distribution infrastructure.

Additionally, CMP stated that its AMI Program would provide "the same level of fundamental benefits to all CMP's 600,000 plus customers throughout its 11,000 square mile service area." These claims of benefits would rely on what the Company termed as "three key building blocks:" [94]

- An AMI network, which provides two-way communications, enables metering-related, dynamic pricing, and distribution automation applications
- Electricity meters which enable metering, power quality monitoring, and HAN, as well as other uses
- A Meter Data Management System to organize the customer information collected

In addition to these benefits, CMP agreed to work with Staff and interested parties to develop and implement the supply side benefit of "one or more voluntary price-based customer demand response programs" to take advantage of the AMI technology. This would include at least one program for residential and small commercial customers.[95]

In February 2010, the Commission issued an Order approving CMP's proposed plan to implement AMI. This Order stated that approval of the Program was premised on the AMI system having certain capabilities:[96]

- Measuring and storing load on an hourly (or less) interval basis:
    - ➢ for residential and small commercial customers; a 15-minute interval basis for commercial and residential and Industrial customers
    - ➢ The two-way communications network will have adequate capacity and capabilities to allow for real-time meter queries and remove software upgrades
    - ➢ The AMI system will have sufficient capacity to store the hourly billing data for load settlement processes, including potential adjustments and corrections
- Measuring and storing the TOU peak demands of each customer as necessary for billing and settling ICAP tags[97] as well as each customer's daily peak demand

[93] CMP Data Response: BRCS-001-029 Attachment 3, pages 3-4 (2010-1-19 CMP Testimony and Request for Decision – CONFIDENTIAL 2007-215 Phase II.pdf).
[94] CMP Data Response: BRCS-001-029 Attachment 3, page 4 (2010-1-19 CMP Testimony and Request for Decision – CONFIDENTIAL 2007-215 Phase II.pdf).
[95] CMP Data Response: BRCS-001-029 Attachment 3, page 11 (2010-1-19 CMP Testimony and Request for Decision – CONFIDENTIAL 2007-215 Phase II.pdf).
[96] MPUC Docket No. 2007-215(ii), February 25, 2010

- Back office and billing systems capable of billing, both T&D and supply, on a TOU basis.
  - These systems will be designed to allow for time periods that differ between T&D and supply and to allow hourly billing for large commercial and industrial customers.
  - The billing and other back office systems will allow loads to be settled in the ISO-NE market systems for all customers based on actual hourly loads rather than load profiles and allow ICAP tags for all customers to be based on actual metering load in the applicable hour, rather than the load profile.
  - The billing and back office systems will allow for multiple standard-offer products within a given standard offer class and allow for bill proration to be performed using metered loads rather than days in the period, as is currently done.
- Remote disconnections and reconnections
- Reliability poll individual meters to evaluate outages and must include an outage tracking system
- Monitoring and measuring voltage variances
- Accommodate "value added" systems and devices (e.g., in-home displays, load control devices)

B. AMI Capabilities Implemented

In interviews and through data requests, the Company stated that it believes that CMP's AMI Program includes **all** of the capabilities as enumerated by the Commission in its February 2010 Order.[98] Included on the following pages is Table 2, which is the Company's response to BRCS-001-030. This response includes an explanation of the Company's position for the status for each of the Commission's delineated capabilities in its February 2010 Order.

[97] The reported ICAP is based on the aggregate of each Supplier's customers' contribution to the ISO-NE peak load during the preceding year. The individual customers' contributions (tags) are estimated annually. The daily Supplier requirements are then calculated by tracking customer enrollment changes and shifting load accordingly. Customers' contributions to ICAP are estimated from either their actual peak hour use, if interval data are available, or load profiles.

[98] CMP Data Response: BRCS-001-031.

Table 9 Company Status of AMI Required Capabilities[99]

MPUC Requested System Capability	Status
Measuring and storing load on an hourly (or less) interval basis for residential and small commercial customers; a 15-minute interval basis for commercial and industrial (C&I) customers, and a less than 15-minute interval basis for specified customers.	**Complete** Meter deployment was completed by June 2012 and all Smart Meters support interval reads (hourly or sub-hourly). Please note a small number of large industrial customers are not currently supported by AMI due to the complexity of the meter. These customers are currently supported by MV90
The two-way communications network will have adequate capacity and capabilities to allow for real-time meter queries and remote software upgrades.	**Complete** The AMI network covers CMP's service area providing both a Wide Area Network (WAN) and Neighborhood Area Network (NAN). CMP has and is successfully executing both remote software upgrades and real time meter queries at scale. There are approximately 2,000 meters in the most Northern region ("ultra remote") of the service area that are not currently covered by the existing network. CMP is working to complete the network coverage for these meters.
The AMI system will have sufficient capacity to store the hourly billing data for load settlement processes, including potential adjustments and corrections.	**Complete** Both the Meter Data Management System and EV8 (Aclara Settlement System) store hourly customer data. The Company will maintain 7 years of archived data.
Measuring and storing the TOU peak demands of each customer as necessary for billing and settling ICAP tags as well as each customer's daily peak demand.	**Complete** The capability is complete. Supply side Time of use pricing capabilities were delivered as of fourth quarter 2012. ISO-NE hourly settlement was delivered on 5/1/2013. On 6/1/2013, CMP implemented the Capability period tag values calculated in accordance to M-20 of the ISO-NE Market Rules.
Back office and billing systems capable of billing, both T&D and supply, on a TOU basis. These systems will be designed to allow for time periods that differ between T&D and supply and to allow hourly billing for large commercial and industrial customers.	**Complete** • Supply-side TOU pricing capabilities were delivered - 4Q12 • Hourly billing for large commercial and industrial customers can be supported manually • The EV8 (Aclara Settlement System) upgrade implemented on 1/1/2012 supports multiple providers. The settlement system allows the same provider to have multiple load assets registered in CMP's service territory, allowing for any number of future pricing options. • Opt out/legacy meters will settle on a load profile so these customers may have limited supply-side pricing options. • Critical Peak Pricing (CPP) business requirements are currently in review with the MPUC Staff. CPP billing capabilities will be available YE2014.
The billing and other back office systems will allow loads to be settled in the 1S0-NE market systems for all customers based on actual hourly loads rather than load profiles and allow ICAP tags for all customers to be based on actual metered load in the applicable hour, rather than the load profile.	**Complete** • ISO-NE hourly settlement based on 100% AMI data was delivered on 5/1/2013. CMP is the 1st utility in New England to support 100% • On 6/1/2013, CMP implemented the Capability period tag values calculated in accordance to M-20 of the ISO-NE Market Rules. Tag values for accounts originally settled on a profile were created using the same load profile. Accounts that were originally settled based on hourly values had tag values based on hourly values.

[99] CMP Data Response: BRCS-001-030, Attachment 1.

MPUC Requested System Capability	Status
	• 6/1/2014 Capability Period tag values will be based on each customer's actual hourly AMI meter reading with the exception of accounts retaining legacy meters. • EV8 supports multiple standard offer providers in a given class • Future enhancements – CMP is developing an export file for suppliers that will contain individual customer hourly load data – target 1Q14 (Capability delivered 12/1/2013) • EV8 will support multiple suppliers providing various dynamic pricing options.
The billing and back office systems will allow for multiple standard-offer products within a given standard offer class and allow for bill proration to be performed using metered loads rather than days in the period, as is currently done.	**Complete** • CSS and EV8 (Aclara Settlement System) as implemented on 1/1/2012 support multiple standard offer providers as demonstrated by the TOU offering 4Q12 • As of 5/1/2013, load settlement is based on AMI meters so actual load is used for all accounts with the exception of those accounts with legacy meters.
Remote disconnections and reconnections.	**Complete** • Over 95% of the meters have a disconnect/reconnect switch installed • Remote disconnect/reconnect capabilities were implemented in a controlled launch April 2011 • Over 140,000 of remote on/off orders were completed in 2011-12
Reliably poll individual meters to evaluate outages and must include an outage tracking system.	**Complete** • All customer service representatives have the ability to ping a meter for a read or to confirm power • AMI meter data was integrated into the Outage Management System by 4Q12 • Meter status information was used to clear outage orders in storms since 1Q2011
Monitoring and measuring voltage variances.	**Complete** • CMP's Smart Meters are capable of recording voltage events and recording average voltage readings over load profile intervals (15 minute data). • Currently, CMP uses the voltage information and event data from Smart Meters on a reactive basis to investigate customer issues or complaints. • The meters were subjected to various voltage sags and swells test conditions. This testing was completed prior to meter purchase and acceptance.
Accommodate "value added" systems and devices (e.g., in-home displays; load control devices).	**Complete** • CMP's Smart Meters have the capability to support HAN devices via the radio in the meter • Preliminary HAN testing was completed during the System Acceptance Test • Additional HAN testing for a number of devices will be initiated 4Q13

The Company stated that as with any new system, opportunity always exists for enhancement to add functionality and capabilities. The Company claims that they will continue to enhance and add additional capabilities to the capabilities previously mentioned.[100]

Concerns with Installed AMI Program Capabilities

In its Order initiating the Management Audit (Docket No. 2010-00051), dated June 17, 2013, the Commission asserted that certain capabilities could not be accommodated by CMP's AMI system. Specifically, the Commission stated the following:

> "As noted above, our approval was based, in part, on the expectation that AMI would enable customers to benefit from demand response and TOU/dynamic pricing programs. Indeed, the Order approving the project required that AMI include certain key capabilities to ensure these benefits would be realized. However, at this point, these benefits are not being realized, in part, because programs cannot currently be accommodated by CMP's AMI and related systems."[101]

Furthermore, Staff noted that on March 20, 2012, the Commission ordered the parameters for the optional "dynamically priced" standard offer service pricing for residential and small commercial customers (Docket No. 2010-00132). The Commission's expectation, according to Staff, was that dynamic pricing options for larger C&I customers would be developed and provided by the retail market and metered and billed by CMP.

Staff also noted that based on limitations in CMP's existing billing systems, the Company cannot bill any TOU or dynamically-priced supply option that would be provided by a retail supplier, except for a TOU price that conforms to CMP's existing T&D TOU period structure, which suppliers have little or no interest in providing. As a result, except for the limited residential/small commercial TOU standard offer, and/or any dynamically priced supply for which retail suppliers bill themselves, customers have no access to the benefits associated with dynamic pricing.

In response to Staff's concern, CMP implemented a manual process to address the requirement of "back office and billing systems capable of billing T&D and supply on a TOU basis." In discussions with Staff, the Company proposed manual billing for standard offer, large industrial/commercial customers as an alternative to modifying the existing billing system. About 40-50 customers are impacted by the dynamic pricing option. An agreement between Staff and the Company was reached recognizing that an interim manual solution was acceptable and a more efficient solution for the small volume of standard offer customers considering the remaining limited life of the current billing system. Rolling out a full-scale hourly pricing option will be addressed when CMP designs the functional requirements for a new billing system.[102]

To address this issue, the Company expects to spend approximately $766,000 on the interim dynamic pricing solution and approximately $1,500,000 on the MDM upgrade.[103] In addition, the Company expects to spend $55 million of capital for a new CSS system and another $4.2m of capital for Meter Data Management/Dynamic Pricing system. Those costs are included in Docket 2013-00168. In November 2007 the Company estimated the cost of CSS integration to support dynamic

---

[100] CMP Data Response: BRCS-001-031.
[101] MPUC Order Initiating Management Audit, Docket No. 2010-00051 (Phase II), June 17, 2013, p.4.
[102] CMP Data Response: BRCS 008-011.
[103] CMP Data Response: BRCS 008-006.

pricing to be $2,431,200. The total estimated cost for CSS integration work was $6,200,000 including all enhancement work to support CSS integration with AMI including integration with the Meter Data Management System, Load Settlement, Meter Asset Management, high-volume meter exchange support, remote services and order development as well as dynamic pricing system development. Actual costs for 2010 through 2012 for CSS integration totaled $3,529,000 which includes cost to implement TOU standard offer and other functions. The cost to complete this work is estimated to be $767,514. The Company expects that these costs will be eligible for 50% reimbursement from the DOE.

However, according to the Company, the rationale for replacing the CSS system is the age and obsolescence of the current system and not because any existing AMI needs are not being met. [104] Based on information provided by the Company, the interim billing solution will be implemented by the end of 2014.[105]

Blue Ridge Assessment

Blue Ridge understands that Staff and the Company have continued to meet to resolve issues of AMI system capabilities even throughout this process of audit. Therefore, Blue Ridge's assessment may not have the most current information agreed to from those meetings.

However, based on the Company's comments (as noted above), the following capabilities are not yet in place:[106]

1. Critical Peak Pricing – expected by year end 2014
2. Hourly billing for large commercial and industrial customers can be supported manually

In interviews, the Company confirmed that both of these will be addressed during this calendar year. Therefore, Blue Ridge found that Commission's and Staff's concern is based in fact. Nothing that the Company has provided Blue Ridge through the audit process suggests otherwise. The Commission and Staff expected dynamic pricing available for all participants in the energy market, i.e., residential, small and large commercial, and industrial, and competitive energy providers - supply.

It is clear to Blue Ridge that, at the very least, time-of-use pricing is available for the delivery component of the customer's bill and for the standard offer service. However, based on all of the information provided, it is also clear the Critical Peak Pricing will not be available until the end of 2014.[107] It is also clear that in the Commission's order in the dynamic pricing case (Docket No. 2010-0132), the Commission stated the following:

> We agree with Staff's initial assessment that, due to substantial implementation complexities, the PTR approach should not be pursued at this time.[108] Instead, CMP should

[104] CMP Data Response: BRCS 008-006.
[105] BRCS-008-009 Att. 1, Page 10 of 23 Docket No. 2013-00476 (**CONFIDENTIAL)**
[106] Regarding ICAP tags based on AMI hourly data, that capability was delivered on 5/1/2013. However due to ISO-NE market rules, the tags for 6/1/2013 were produced based on profiles as the load for that peak season was settled based on profiles. Thus, although the capability to create capacity tags based on AMI hourly data was already in place, CMP will employ that capability for the first time for the upcoming Capability Period beginning 6/1/14.
[107] See BRCS-001-030 Attachment 1 page 1.
[108] In a footnote, the Commission stated, "The Public Advocate commented that a PTR approach would be preferable because customers may be more responsive to a rebate program, as opposed to a program that could result in higher rates. Although we do not disagree with the Public Advocate's view in this regard, as stated above, due to the complexities of implementation, we will not pursue this approach at this time."

> program its systems to be able to broadly offer at least two pricing options; TOU and CPP pricing options (as well as an alternative that combines both pricing approaches).
>
> To avoid the complexities involved in billing for supply and T&D using different time periods, the TOU standard offer option will employ the existing time periods for T&D (without the shoulder periods). Customers that choose the TOU standard offer option may also choose (but will not be required to choose) the T&D TOU rate.
>
> With respect to hourly pricing, we understand that it is impractical for CMP to design its systems to allow for the prospect of a large number of its customers choosing this option, especially when only a small percentage of customers are likely to do so. However, we expect CMP to design its systems, within reasonable cost limitations, so that at least some percentage of CMP customers could take advantage of an hourly pricing alternative.[109]

Blue Ridge also found that, based on its review including interviews, data requests, the Company's testimony in 2007-215, and subsequent filings, CMP had committed to provide supply side dynamic pricing options. One document in particular, ***CMP's AMI Project Execution Plan,***[110] clearly states, "to enable electricity suppliers to create dynamic pricing options for customers."[111] Further, this plan states that one of the benefits of the AMI system would be "[a]n updated customer billing system to support new incentive rates that [*sic*] **expected from the Maine PUC and from third-party energy providers**." (emphasis added)[112]

Based on this information, there is little room to allow a "benefit of the doubt" that the Company's interpretation of what was intended at the outset of the implementation of AMI was different from what the Commission and/or Staff believed the Company promised. However, it is not clear in either the Project Execution Plan or the System Integrator work scope where this capability—dynamic pricing for suppliers—was addressed. Blue Ridge reviewed the system integrator RFP work scope and could not find where the capability to offer TOU pricing on the supply side was ever contracted out. Therefore, it is not clear that CMP actually included work steps to implement this function.

That said, the fact remains that CMP's system as it stands now does not support the depth of what the Commission envisioned in its approval of the AMI Program on the supply side for TOU or CPP. However, the Company provided sufficient information that these issues will be addressed with the new billing system.

In response to our request concerning what we believe is the disconnect between what the Company believed it had committed to and what the Commission (and Staff) expected, the Company provided a detailed explanation. The full response is shown below.

BRCS-006-002

Q. On March 20, 2012, the Commission issued an order (Docket 2010-132) concluding that the dynamic pricing program should be structured as an optional standard offer service.

[109] MPSC Order – Docket No. 2010-0132, dated March 12, 2012, page 4-5
[110] Provided in response to BRCS-001-002 Attachment 3
[111] Ibid. at page 6 of 28
[112] Ibid.

a. Did CMP indicate at any time during the proceeding that the result ordered would require substantial additional investment? If so, please provide supporting documentation.
b. What is the Company's current projection of cost for this work beyond the cost indicated in 2.a? Please provide an explanation for the change, if any, in cost.
c. At the time of the Order, how long did the Company anticipate it would take to complete the work? Please provide documentation.
d. What is the Company's current projection for completion of the work? Please provide an explanation for the change, if any, in duration of implementation.

A.

a. In CMP's November 2007 Rebuttal testimony, the Company had estimated the cost of CSS Integration to support dynamic pricing to be $2,431,200.[113] As noted in the November 2007 filing, CMP stated, "the Company has done further analysis of the required changes to its billing system, has confirmed its ability to enhance the current billing system, and has included the approximately $2.2 million incremental cost in both the revenue requirement calculations in this case and the attached revised cost/benefit model. [cite omitted] As such, CMP's billing system can and will support supply-based demand response programs as filed with CMP's AMI System proposal in this testimony." *See* Rebuttal Testimony of Mary Elizabeth Nowack Cowan and Gary Fauth in *Re Central Maine Power Company, Request for Alternative Rate Plan ("ARP 2008")*, Docket No. 2007-215 (Nov. 9. 2007), p. 5, ln 9-14. The total estimated cost for CSS integration work was $6,229,175. The $6.2 million estimate included all enhancement work to support CSS integration with AMI including integration with the Meter Data Management System, Load Settlement, Meter Asset Management, high-volume meter exchange support, remote services order development, as well as dynamic pricing system development.

b. Actual Costs for 2010 through 2012 for CSS Integration totaled $3,528,837. This includes costs to implement the alternative Time of Use ("TOU") standard offer service offering. Incremental work to support Critical Peak Pricing ("CPP") structures is currently in progress. The cost to complete this work is estimated to be $767,514. The Company expects that these additional costs will be eligible for 50% reimbursement from the DOE pursuant to its SGIG grant award.[114]

c-d. CMP filed Attachments 1 and 2 in the Commission's Docket No. 2010-132, Investigation into Central Maine Power Company AMI-Related Programs. In these filings, the Company proposed a process to work with the Commission Staff to define detailed business requirements for dynamic pricing capabilities. The definition of Staff's business requirements would help the Company more fully understand the system development effort, cost and schedule impacts for the new pricing programs. As stated in the attachments, the proposal assumed that once the requirements were defined, the Company would then provide a time and cost estimate which could then be approved or revised by the Staff. Although a formal facilitation process was not conducted, the Company and Staff have worked collaboratively to define the business requirements. In these discussions, CMP agreed to deliver the dynamic supply-side TOU standard offer rates for enrollment in December 2012. This capability was delivered on time. CMP is currently working collaboratively with the Staff to develop the business requirements for CPP rates. The capability to implement CPP dynamic rates will be delivered by the

[113] CMP Response to BRFC 006-002.
[114] CMP Response to BRC 006-002.

> end of 2014. Because the Company has been working collaboratively with the Staff to development business requirements, the Staff is aware of the timing for the delivery.

Therefore, based on the documentation referenced in this response, it is also clear that the Company from very early in the process was indicating that additional work would be required. The Company's response notwithstanding, the information we reviewed shows that CMP did commit to provide dynamic pricing capability on the supply side as part of the original approval process.

What remains to be determined, then, is whether the cost of meeting the Commission's original expectations, which could be argued would have been included in the original AMI Program cost approval, is now being included in the cost of the new billing system that is the subject of the current rate case. In data responses and interviews, the Company has confirmed that some of the costs (approximately $4.3 million in capital and O&M) are related to the dynamic pricing issue and providing the capability that the Commission expects. This gives rise to the question: *"Is the Company asking to be paid twice for the same capability?"*

Blue Ridge has reviewed the relevant data requests, documents, and through the interview process concluded that with respect to the supply side, it is not likely that the original project cost estimate, while well developed, included this capability. Blue Ridge reviewed the RFP scope for the system integrator and did not see where the capability to provide dynamic pricing (as described above) was included in the contractor's scope of work. We were able to see the ISO-NE settlement work and the ICAP tag capability but did not find a work task or step that would show that the contractor was requested to develop this capability. However, given the complexity and number of contractors that were utilized, it is possible that the work scope was included. In addition, it is possible the work tasks associated with this capability could have been assigned to in-house resources. Given the complexity of the work plans for the project, it is possible that CMP did attempt to provide the capability.

C. Overall Conclusion for AMI Program Capabilities

Blue Ridge found that the Company has implemented a significant portion of what the Company provided in its initial and subsequent filings requesting approval for AMI. However, the dynamic pricing issue for the supply side has not been fully implemented but will be addressed in the new billing system. While Blue Ridge did not find evidence that CMP paid for a capability it did not implement, the possibility does exist that some project funds were allocated to complete this function which was not delivered. However, what is lost is the potential savings value of the dynamic pricing option that customers (and suppliers) may have taken advantage of had the capability been available.

APPENDICES

Appendix A: Document Management System – Data Requests

Appendix B: Internal and External Reports

Appendix C: Regulatory Filings

Appendix D: Staff Comments and Blue Ridge Response

Appendix E: CMP Comments and Blue Ridge Response

APPENDIX A: DOCUMENT MANAGEMENT SYSTEM

#	DR #	Request
1	CMP-01.01	Background. Please provide any and all documented procedures and/or policies by which the AMI project costs were determined for the original estimates in January 2010.
2	CMP-01.02	Background. Please provide a copy of the Company's AMI Project Implementation/Work Plan. Include the original and updated master schedules, including any timelines, analyses, or detailing of the events and timing of the AMI project.
3	CMP-01.03	Background. Please provide a project organization chart (titles, names) from the AMI project inception to date. Include any modifications to the chart identifying date of change and reason for change.
4	CMP-01.04	For each person on the AMI project team, identify the person's originating department.
5	CMP-01.05	Please provide original planned staffing levels for the AMI project team that were and/or are included in the AMI cost projections and all project staffing changes that have taken place through the most recent date available.
6	CMP-01.06	Please provide a narrative describing the roles and responsibilities of the AMI project team.
7	CMP-01.07	Background. Please provide a comprehensive list of the industry data and research material that CMP relied upon in designing, costing, and implementing its AMI project.
8	CMP-01.08	Cost and Savings Determination. Please provide the specific steps used and analysis applied, as referred to by Company witness Paul Dumais in the January 22, 2010, hearing on the AMI Project, to vet the savings projection included in the January 19, 2010, Company testimony submitted to the Commission.
9	CMP-01.09	Cost and Savings Determination. Please provide the documentation associated with the independent modeling of the savings projection as mentioned by Company witness Paul Dumais in the January 22, 2010, hearing on the AMI Project.
10	CMP-01.10	Cost and Savings Determination. Please provide the Company's cost-benefit analysis for the AMI Project as referred to in the Commission's February 25, 2010, Order Approving Installation of AMI Technology, Docket No. 2007-215(II).
11	CMP-01.11	Cost and Savings Determination. Please provide all updates in original Excel or other format with all cell calculations intact for projected savings and associated studies (e.g., CMP's travel time study) produced since January 19, 2010.
12	CMP-01.12	Cost and Savings Determination. Please provide a list of assumptions and the basis of those assumptions used to develop the original cost and savings estimates in January 2010.
13	CMP-01.13	Cost and Savings Determination. Please provide the calculations along with descriptive narrative of the calculations for the original (January 2010) AMI project cost/savings estimates.
14	CMP-01.14	Cost and Savings Determination. Please provide final, actual savings and costs determined for the AMI project.
15	CMP-01.15	Project Implementation and Management. Please provide a narrative describing the project management process, including the dates of its development.
16	CMP-01.16	Project Implementation and Management. Please provide samples of the Internal and external periodic reports (including progress or status reports) issued regarding the AMI project, including frequency and distribution.
17	CMP-01.17	Project Implementation and Management. Please provide a chronological list with dates of project cost or expected savings changes, the reason(s) for the change, and supporting documentation demonstrating the justification for the change and a list the person(s) responsible for approving AMI project cost overruns. Include the title and specific date that the change was authorized and contemporaneous documentation showing change was approved.
18	CMP-01.18	Please provide the criteria by which AMI project overruns were assessed for approval.
19	CMP-01.19	Project Implementation and Management. For each cost overrun assessed, please provide a description of the Company's processes to mitigate the cost increases.

#	DR #	Request
20	CMP-01.20	Project Implementation and Management. Provide a list of audits conducted by the Company's Internal or External Auditors on the AMI Project since January 2010 to date. Include the date of the audit, the date of the final report, the audit team lead and the person(s) the final audit report was delivered to.
21	CMP-01.21	Project Implementation and Management. Please provide original outsourcing/vendor selection plans for the project.
22	CMP-01.22	[CONFIDENTIAL ATTACHMENTS] Project Implementation and Management. Please provide vendor and contractor procurement procedures.
23	CMP-01.23	Project Implementation and Management. Please provide a copy of the original RFP(s) or entire bid package for the AMI Project system contractors, consultants, vendors, suppliers, and/or other outside parties, along with a listing of intended recipients and how these recipients were qualified to receive the RFP.
24	CMP-01.24	[CONFIDENTIAL] Project Implementation and Management. Please provide copies of all analyses, spreadsheets, evaluations, investigations, correspondence, and other information associated with selection of any contractors, consultants, vendors, suppliers, other outside parties, and/or systems, including dates, presentations, agenda, and notes from meetings.
25	CMP-01.25	Project Implementation and Management. Please provide the name and title of the person responsible for making outsourcing decisions for the AMI project.
26	CMP-01.26	Project Implementation and Management. Please provide a list of all outsourced contracts for the AMI project, including the contract value, the contract terms, and expected deliverables.
27	CMP-01.27	Project Implementation and Management. Please describe the processes used by the Company to oversee the work product of the contractors on the AMI project.
28	CMP-01.28	Project Implementation and Management. By contractor, please provide a list of any scope changes during the AMI project, including the value of the change, the date of the change, the reason and analysis that supports the scope change.
29	CMP-01.29	[CONFIDENTIAL ATTACHMENTS] AMI Capabilities: Planned and As Built. Please specify all AMI capabilities as originally conceived and presented in January 2010.
30	CMP-01.30	AMI Capabilities: Planned and As Built. Please specify all AMI capabilities as implemented, including describing any changes or deletions of the January 2010 originally presented capabilities.
31	CMP-01.31	AMI Capabilities: Planned and As Built. Please provide a narrative describing all AMI capabilities that were not implemented and provide the reasons for not implementing them.
32	CMP-01.32	Regulatory Accounting. Please identify and list those costs that are in the original revenue requirements calculation. This list can be broken done by functional area, labor, overhead, M&S, misc. etc.
33	CMP-01.33	Regulatory Accounting. Please identify and list those costs that ARE NOT in the original revenue requirement calculation. This list can be broken done by functional area, labor, overhead, M&S, misc. etc.
34	CMP-02.01	{CONFIDENTIAL RESPONSE} Please provide the kickoff meeting (10/7/13) presentation as an MS powerpoint file.
35	CMP-02.02	Regarding the Information Technology (IT) department/function during the AMI project, please provide the following documentation regarding Company personnel charging to the AMI program: a. As described by Donna McNally, an example of the monthly report used to review who within IT was charging to the AMI program and how much was being charged. b. An example of the time exception report used for noting when a corrected adjustment was made by an employee (or contractor) who incorrectly charged time to the AMI project. c. An example of an incident in which an exception was noted of a person incorrectly charging time to the AMI program and the resolution thereof.

#	DR #	Request
36	CMP-02.03	Referring to the interview with Steve Faulhaber, please provide a copy of the documentation that supports his statement that an AMI meter manufacturer stated that CMP's testing process had "changed the industry." In addition, please provide any other recognition from other utilities, vendors, or industry organizations that give evidence to any recognition concerning the quality of performance by CMP regarding the AMI project.
37	CMP-02.04	Please provide inventory data concerning meters: number (separate count of legacy and AMI meters), return rates, and turnover statistics. Please provide the basis and rationale upon which the Company has established its current inventory level of AMI and Legacy Meters.
38	CMP-02.05	Referring to the response to BRCS-01-020, please provide copies of the following audit reports: a. Project Cost Verification Audit; External; 2Q13; Jul-13; Lead: Steve DeNoon, KPMG, LLC; Delivered to: Ryan Egidi, Energetecs, Inc. b. A-133 Review; Internal; 2Q12; 27-Apr-12; Lead: Mark Sinclair, Iberdrola USA Management Corporation; Delivered to: Laney Brown and Bob Fitzgerald c. Project-to-Live Transition Review; Internal; 4Q12; 29-Dec-12; Lead: Mark Sinclair, Iberdrola USA Management Corporation; Delivered to Laney Brown
39	CMP-02.06	Referring to the interview with Brenda Benner, please provide the work process flow diagrams (Vizio) for billing, customer service, communications, field operations, and training.
40	CMP-02.07	Referring to the interview with Brenda Benner, please provide an example of the powerpoint used for training of CMP personnel for AMI related business process changes.
41	CMP-02.08	Referring to the interview with Rachel Grenier, please provide the following: a. For each process in which AMI had a direct impact, identify the benefits to other portions of the process resulting from AMI implementation (e.g., Disconnect for Non-pay verification.) b. Identify other processes that benefitted from AMI program which had not been envisioned in the original cost benefit assessment but became evident after implementation (e.g., multiple bill pay). List the benefits for each process. c. If available, provide quantification of the benefits identified in a and b above.
42	CMP-02.09	As discussed in Laney Brown interview, please provide a list of the major changes in cost (including their costs) that occurred during the AMI program.
43	CMP-02.10	As discussed in Leona Michelsen interview, please provide a copy of the Research Study report when it is issued.
44	CMP-02.11	With respect to AMI project cost benefit analysis contained in the August, 2012 filing with the MPUC and the AMI project revenue requirement analysis contained in the Company's March 2013 rate case filing, is the Company considering either a: developing an analysis of the cost benefit assessment associated with the March 2013 filing similar to the August 2012 filing. a. If yes, when will that analysis be available? Please provide that analysis when it does become available. b. If no, is the Company considering a reconciliation between the two filings? If yes, when will that analysis be available? Please provide that analysis when it does become available.
45	CMP-03.01	[CONFIDENTIAL RESPONSE] According to testimony provided by CMP to the Commission on January 19, 2010, "On August 6, 2009, CMP submitted to the DOE a confidential Smart Grid Investment Grant Application." Please provide a copy of that confidential application. (Electronic version is sufficient.)
46	CMP-03.02	Referring to the interview with John Miller on October 18, 2013, please provide the following: a. The quarterly management reports showing IT resources assigned to the AMI Project by functional area of the project. b. Examples of the management reports from the individual functional areas
47	CMP-04.01	[CONFIDENTIAL ATTACHMENTS] Please provide all meeting minutes for the period March 2010 through end of project (December 2012) for the following: a. Steering Committee b. AMI Leadership Team
48	CMP-04.02	Referring to the interview with Susan Clary and Eric Stinneford on October 24, 2013, please provide the estimate cost of CIS as it relates to development in regard to the AMI Program.

#	DR #	Request
49	CMP-04.03	Referring to the interview with Susan Clary and Eric Stinneford on October 24, 2013, please provide the testimony presented to the Commission concerning the industry research as to how customers could benefit from AMI.
50	CMP-04.04	[CONFIENTIAL RESPONSE] Referring to the sample reports provided in response to DR BRCS-001-016, please provide the following reports covering the period from March 2010 through the last issuance of each report for the AMI Program: a. BRCS-001-016, Attachment 004 – AMI Program Status Report Summary-Weekly b. BRCS-001-016, Attachment 006 – CEO AMI Monthly Report c. BRCS-001-016, Attachment 007 – CMP President Status Biweekly d. BRCS-001-016, Attachment 008 – Iberdrola Networks Business Committee Bimonthly e. BRCS-001-016, Attachment 009 – DOE CMP Monthly Progress Report f. BRCS-001-016, Attachment 016 – AMI Update PSCv4
51	CMP-05.01	Please provide the capital workorder(s) for the AMI project along with any supporting documentation, including internal rate of return, savings, and cost projections. Also, please provide any supplements (change orders) and corresponding supporting documentation.
52	CMP-06.01	Technology (Docket 2007-215) at page 7&8, the Commission stated the following regarding AMI capabilities: “Our approval of CMP’s AMI project is explicitly premised on the system having the capabilities specified in CMP’s January 19, 2010 testimony and its DOE grant application.” The Order goes on to list specific capabilities that the AMI system was expected to have: • Measuring and storing load on an hourly (or less) interval basis for residential and small commercial customers; a 15-minute interval basis for commercial and industrial (C&I) customers, and a less than 15-minute interval basis for specified customers. The two-way communications network will have adequate capacity and capabilities to allow for real-time meter queries and remote software upgrades. The AMI system will have sufficient capacity to store the hourly billing data for load settlement processes, including potential adjustments and corrections. • Measuring and storing the TOU peak demands of each customer as necessary for billing and settling ICAP tags as well as each customer’s daily peak demand. • Back office and billing systems capable of billing, both T&D and supply, on a TOU basis. These systems will be designed to allow for time periods that differ between T&D and supply and to allow hourly billing for large commercial and industrial customers. The billing and other back office systems will allow loads to be settled in the ISO-NE market systems for all customers based on actual hourly loads rather than load profiles and allow ICAP tags for all customers to be based on actual metered load in the applicable hour, rather than the load profile. The billing and back office systems will allow for multiple standard-offer products within a given standard offer class and allow for bill proration to be performed using metered loads rather than days in the period, as is currently done. • Remote disconnections and reconnections. • Reliably poll individual meters to evaluate outages and must include an outage tracking system. Monitoring and measuring voltage variances. • Accommodate “value added” systems and devices (e.g., in-home displays; load control devices). For each of these capabilities, please provide the following: a. The original estimated cost for the capability as presented to the Commission in January 2010 b. The original estimated savings expected for the capability in January 2010 c. The date of completion of implementation of the capability (Please provide forecasted date of implementation if not yet implemented) d. The actual cost (or, if not completely implemented, current projected cost) for the capability as implemented (including explanation of difference from original estimated cost above) e. The estimated savings expected for the capability as of the Company’s March 2013 filing (including explanation of difference from original estimated savings above) f. If the capability is one not considered by the Company as having been committed to for the AMI Program, an explanation regarding the Company’s position

#	DR #	Request
53	CMP-06.02	On March 20, 2012, the Commission issued an order (Docket 2010-132) concluding that the dynamic pricing program should be structured as an optional standard offer service. a. Did CMP indicate at any time during the proceeding that the result ordered would require substantial additional investment? If so, please provide supporting documentation. b. What is the Company's current projection of cost for this work beyond the cost indicated in 2.a? Please provide an explanation for the change, if any, in cost. c. At the time of the Order, how long did the Company anticipate it would take to complete the work? Please provide documentation. d. What is the Company's current projection for completion of the work? Please provide an explanation for the change, if any, in duration of implementation.
54	CMP-06.03	Please enumerate all benefits of the TOU standard offer regarding the following: a. Expected benefits as of the March 20, 2012, Order b. Current expected benefits c. Explanation of any differences between 3.a and 3.b
55	CMP-07.01	Referring to BRCS-001-016. The list of attachments in Response BRCS-001-016 lines 14 and 15 indicate that the DOE Impact Metrics are quarterly and the DOE Build Reports are semi-annual reports while Attachment 1 of BRCS-001-016 indicates that the Build Metrics are quarterly and the Impact Metrics Reports are semi-annual. Please clarify whether or not the reports are quarterly or semi-annual reports.
56	CMP-07.02	Referring to BRCS-001-016. Please provide a sample of the Quarterly DOE Job Reporting and Monthly Risk Management Date Update referred to in attachment 1 of BRCS-001-016.
57	CMP-07.03	Referring to BRCS-004-004. Please provide the AMI Program Status Reports for the following weeks:
58	CMP-07.04	Referring to BRCS-004-004. Please provide the CMP President Status Biweekly Reports for the following weeks:
59	CMP-07.05	Referring to BRCS-004-004. Please provide the Iberdrola Networks Business Committee Bimonthly Reports for the following weeks:
60	CMP-08.01	Follow up to Data Request response BRCS-001-008, attachment 1, page 3 and 4 – Remote Reconnect/Disconnects. Referring to the Remote Reconnects/Disconnects, what was the actual FTE reduction for employees for this category of savings as of March 2013?
61	CMP-08.02	Follow up to Data Request response BRCS-001-008, attachment 1, page 3 and 4 – Remote Reconnect/Disconnects. What does the Company estimate the savings to be that are attributable to this category as of December 31, 2013?
62	CMP-08.03	Follow up to Data Request response BRCS-001-008, attachment 1, page 3 and 4 – Remote Reconnect/Disconnects. Please fully explain any difference in the employee headcount reduction between the original January 2010 and the March 2013 headcounts for this category.
63	CMP-08.04	Follow up to Data Request response BRCS-001-032. Please fully explain what comprises the outside services costs in 2013 ($2,038). Explain why these costs are considered outside services (column 2, line 1) – AMI Network and were not included in the January 2010 filing.
64	CMP-08.05	Follow up to Data Request response BRCS-001-028, attachment 1. Please categorize the change orders listed in the above referenced response in the following categories: a. Not considered in original scope b. Change due to delays by the vendor c. Change due to delays by the Company d. Change due to another reason (fully explain)

#	DR #	Request
65	CMP-08.06	Back Office/Billing System Capability. Docket 2013-00168 includes substantial capital investments of approximately $55 million for a customer relationship management and billing system and $4.2 million for Meter Data Management/Dynamic pricing system. a. Please categorize these costs by component categories (e.g., hardware, software, in-house labor, contractor costs and overheads). b. Please identify any functionality included in the scope of work for each of these systems (i.e., customer relationship management and billing system and the Meter Data Management /Dynamic pricing system) that was originally included in the approved AMI project scope issued by the Commission in Docket No. 2007-215(1) on February 25, 2010. c. Please identify the capital and O&M costs for the period January 2013 to date associated with the functionality of the billing for TOU and T&D billing from AMI reads for each of the following: i. Manual billing of TOU and T&D AMI customers ii. Interim IT costs for moving from a manual to an automated billing iii. Permanent automated solution
66	CMP-08.07	The AMI Program Governance Plan, page 21, states, “If any of the following conditions apply, the project manager will provide an explanation and a recovery plan in an e-mail to the PMO accompanying their weekly status reports: • Any key milestone or deliverable is forecast more than one week late • Any key milestone or deliverable actually occurs more than one week late • Any tasks that were scheduled to start/complete within the current period did not start/complete” Please provide 10 examples of such emails.
67	CMP-08.08	The AMI Program Governance Plan, page 21, states, “If any of the following conditions (for hours or dollars) are identified by the PMO, they will ask the Project Manager via e-mail for an explanation and recovery plan, which will be due to the PMO within 2 business days • Variance of earned schedule vs burned schedule < -5% • Estimate at completion burn % > 105%” Please provide 10 examples of such emails.
68	CMP-08.09	Please identify the date when the Company determined that the billing system would have to be replaced to accommodate automated processing of TOU/Dynamic Pricing as outlined in the Commission February 2010 order? Provide the contemporaneous documentation to show when senior management was 1st presented with this recommendation to replace the billing system.
69	CMP-08.10	Based on our review of the BRCS-001-029, Attachment 1, and BRCS-001-030, Attachment 1, the response to BRCS-001-030, Attachment 1, was incomplete. Please identify the current status of the following capability noted in BRCS-001-029, Attachment 1: • Measuring and storing the TOU peak demands of each customer as necessary for billing and settling ICAP tags as well as each customer's daily peak demand.
70	CMP-08.11	Follow-up to Data Request BRCS-001-030, attachment 1, page 1, MPUC Requested System Capability, Column 4, Back Office and Billing systems In its February 25, 2010, Order, the MPUC requested, “Back office and billing systems capable of billing T&D and supply, on a TOU basis. These systems will be designed to allow for time periods that differ between T&D and supply and to allow hourly billing for large commercial and industrial customers.” In the above referenced DR response, the Company responded that this item was completed by stating in part, “Hourly billing for large commercial and industrial customers can be supported manually.” Please provide the Company’s understanding of how the Company’s above response satisfies the Commission’s request for “Back office and billing systems” (emphasis added).

APPENDIX B: INTERNAL AND EXTERNAL REPORTS[115]

1. The Project Manager submitted a *Daily Deployment and Project Metrics* report[116] to the Program Lead Team and AMI Steering Committee on a daily basis. The *Daily Deployment and Project Metrics* report included charts to show these items:
    a. Success and Volume of Remote Activations of Service On/Off Switches (1-day, last 5 days, last 15 days)
    b. Registered Read Daily Success
    c. Service Area Look with 3-day view
    d. 3-day read success rates
    e. Daily Success Percentages

2. The Project Manager submitted weekly *Detailed Status Reports*[117] to the Program Lead Team. The *Detailed Status Reports* show the following items:
    a. AMI Program Summary:
        i. Actual to Budget Spend details (YTD and Total)
        ii. Internal Resources (Hours and dollars charged)
        iii. Amount reimbursed by DOE (YTD and Total)
        iv. Snapshot of Scope, Schedule, Budget for the past and current week
        v. Percent of Phase and Program Completed
    b. Project Snapshot on whether or not there are any issues being mitigated; emerging issues; current issues impacting the project; whether or not the project has been started, completed, or on hold; and also Trend Arrow forecasting the status for the next period.
    c. Weekly Milestones
    d. Project Detail – Program Issues/Areas of Concern
    e. Risk Log Spreadsheet
    f. Project Details: Milestones (forecast for 90 days), completed tasks, upcoming tasks, new requirements, on hold, etc.

3. The AMI Project Director submitted weekly *Summary Status Reports*[118] to the AMI Steering Committee, CMP, and Iberdrola USA and Iberdrola SA executives. *Summary Status Reports* show the following items:
    a. AMI Program Summary:
        i. Actual to Budget Spend details (YTD and Total)
        ii. Internal Resources (Hours and dollars charged)
        iii. Amount reimbursed by DOE (YTD and Total)
        iv. Snapshot of Scope, Schedule, Budget for the past and current week
        v. Percent of Phase and Program Completed
    b. Project Snapshot on whether or not there are any issues being mitigated; emerging issues; current issues impacting the project; whether or not the project has been started, completed, or on hold; and also Trend Arrow forecasting the status for the next period.
    c. Plans for the current and following week
    d. AMI Program Status (Current Status, Project Goals, % Complete): Meters Installed, % AMI Read on Bills, Capital Spend, AMI Daily System Reads
    e. Network Collector: Collectors read performance at 97%
    f. Meter Read on Bills: Target and Actual
    g. Project Detail – Program Issues/Areas of Concern

---

[115] CMP Data Response: BRCS-001-016.
[116] CMP Data Response: BRCS-001-016 Attachment 2.
[117] CMP Data Response: BRCS-001-016 Attachment 3.
[118] CMP Data Response: BRCS-001-016 Attachment 4.

4. The AMI Project Director submitted weekly *Summary Status Reports*[119] to the Iberdrola USA CEO. The *Summary Status Reports* show these items:
    a. AMI program status report (Weekly and Total)
        i. Meters Installs
        ii. Meter Installs including confirmed opt out
        iii. Reads on Bills
    b. Status on daily meter read (high's and trend)
    c. Status on network installs (% Complete of Core, Non-Core, and Total)

5. The AMI Project Director submitted monthly *Summary Status Reports*[120] to the Iberdrola USA CEO. The *Summary Status Reports* show these items:
    a. Cumulative smart meter installs
    b. % of Daily Billing Reads
    c. Cumulative AMI read on bills to date
    d. Number of truck rolls that have been eliminated
    e. Opt out rate

6. The AMI Project Director submitted bi-weekly *Progress Reports*[121] to the CMP President's Lead Team. The *Progress Reports* show the following items:
    a. Smart Meter Project Progress (Current Status, Project Goal, % Complete, Target Date)
        i. Meters Installed
        ii. % AMI Reads used for Billing
        iii. Daily System Reads
        iv. Capital Spend
    b. Project Update
    c. % AMI Reads on Bills (Current Year)
    d. 1 Day and 3 Day Reads
    e. Recap, Areas of Focus, Opportunities, LOE/Impact of Daily Reads
    f. Register Reads (Actual vs Plan)

7. The AMI Project Director submitted Bi-Monthly *Progress Reports*[122] to Iberdrola USA and Iberdrola SA executives. The *Progress Reports* show the following items:
    a. Smart Meter Project Progress (Current Status, Project Goal, % Complete, Target Date)
        i. Meters Installed
        ii. % AMI Reads used for Billing
        iii. Daily System Reads
        iv. Capital Spend
    b. Areas of Progress

The following is a list of the eight external reports required by the DOE:

1. Monthly Progress Reports include the Company's major accomplishments, changes in approach, actual or anticipated problems or delays and actions taken or planned to resolve them, and Changes in Consortium/Team Members.[123]

2. Monthly PVMS Data in excel format shows baseline, actuals, jobs, milestones, and risk.[124]

[119] CMP Data Response: BRCS-001-016 Attachment 5.
[120] CMP Data Response: BRCS-001-016 Attachment 6.
[121] CMP Data Response: BRCS-001-016 Attachment 7.
[122] CMP Data Response: BRCS-001-016 Attachment 8.
[123] CMP Data Response: BRCS-001-016 Attachment 9.
[124] CMP Data Response: BRCS-001-016 Attachment 10.

3. Monthly Risk Management Date Update is part of the Monthly PVMS Data and shows risks in the final tab named "Risks."[125]

4. Monthly DOE Invoice shows the following items:[126]
    a. Personnel (Number of Hours, Hourly Rate and Total Cost)
    b. Fringe Benefits (Personnel Costs, Rate, Total Fringe Benefit Costs)
    c. Equipment (Paid Invoices and Receipts)
    d. Supplies (General and Telephone)
    e. Contractual (Paid Invoices and Receipts)
    f. Construction
    g. Other (Employee Transportation/Mileage), Other (Employee Meals/Lodging), Other (Other Occupancy/Leases), and Other (Undepreciated Meter Costs)
    h. Total Direct Charges
    i. Indirect Charges
    j. Total Outlays this Period
    k. Federal Cost Share
    l. Non-Federal Cost Share

5. Quarterly Federal Reporting.gov provides Standard Form 425[127] and Federal Reporting – Grants & Loans (Prime Recipient, Sub Recipients, and Vendors).[128]

6. Semi-Annually Impact Metrics and Benefits report provides Geographic Sub-region Map, Reporting Periods, Distribution Impact Metrics Reporting, and AMI Impact Metrics Reporting.[129]

7. Quarterly Build Metrics show the following items:[130]
    a. AMI Assets – Build Metrics
        i. AMI End Points Installed
        ii. Implemented Meter Features
        iii. Implemented Enterprise Integration
        iv. AMI System Descriptions
        v. AMI Enterprise Integration Descriptions
        vi. AMI Installed Costs
    b. Customer Systems Assets – Build Metrics
        i. Implemented Customer Systems
        ii. Web Portal
        iii. Customer System Descriptions
        iv. Customer System Installed Costs
    c. Pricing Programs – Build Metrics
        i. Implemented Rate Plans
        ii. Rate Plan Descriptions

8. Quarterly DOE Jobs Reporting provides the number of jobs created and retained and their descriptions.

In addition to the fifteen types of internal/external reports, the Company produced three presentation updates to the Commission with respect to the AMI project. In these presentations, the Company provided a brief description of the AMI Program, Stage 1 (meter installations and Ongoing Communications Plan), Stage 2 (Network Installation and Network Coverage), Stage 3 (Central System Integration), Stage 4 (End-to-end read on bills, Network performance issues, and Network performance resolutions), Stage 5 (Process

[125] CMP Data Response: BRCS-001-016 Attachment 10.
[126] CMP Data Response: BRCS-001-016 Attachment 11.
[127] CMP Data Response: BRCS-001-016 Attachment 12.
[128] CMP Data Response: BRCS-001-016 Attachment 13.
[129] CMP Data Response: BRCS-001-016 Attachment 14.
[130] CMP Data Response: BRCS-001-016 Attachment 15.

enhancements), Summary of the last 6 months, Yearly Milestones, Benchmarking Progress, AMI – Foundation for Smart Grid, Future – Customer Portal, Future – Outages, Future – Conservation Voltage Reduction, and a Conclusion.[131]

APPENDIX C: REGULATORY FILINGS

1. *January 19, 2010 Filing* - CMP filed a comprehensive filing that addressed the AMI Revenue Requirements which included: (1) explanation of Savings Calculation and methodology for future changes, (2) narrative on rate-making that included discussions of distribution and transmission, customer cost allocations, prematurely retired meters and levelization, (3) examples of changes in capital from estimate to actual and changes in customer cost allocator, and (4) the current forecast (at that time) of the AMI revenue requirement and supporting calculations. *Regulatory Filing: Docket No. 2007-215II, Attachment 4, Parts 1 through 5.*

2. *March 2010 Filing* - An update to the AMI Revenue Requirement was filed as part of the Company's ARP Annual Filing. *Regulatory Filing: Docket No. 2010-051.*

   Next Steps:
   - *The PUC Staff requested a time study be done in order to validate the time for the reconnection and disconnection field service work.*
   - *The Company was in agreement and proposed the time study be conducted in three service centers on three separate days. (The proposal was filed on March 25, 2010.)*
   - *The PUC Staff proposed five service centers on three separate days.*
   - *The Company agreed and provided a written document of how the study would be conducted to the Staff on April 9, 2010.*

3. *May 2010 Filing* - Primarily updated as the result of the Time Study conducted in April and May 2010. *Regulatory Filings: Docket No. 2010-051, Attachment 15A, ODR-02-07, Attachments 1 through 6, ODR-02-09.*

4. *July 2010 Filing* - PUC Staff requested through a Procedural Order on June 24, 2010, the Company provide an update to assumptions for the AMI Revenue Requirement. *Regulatory Filings: Docket No. 2010-051II.*

5. *March 2011 Filing* - An update to the AMI Revenue Requirement was filed to coincide with the Company's regular ARP Annual Filing. Included were updates on carrying costs, inclusion of tax gross-up on legacy meter retirements, inclusion of estimated impacts of bonus depreciation, and inclusion of estimated impacts of labor transition plan. *Regulatory Filings: Docket No. 2010-051II.*

6. *July 2011 Filing* - An update to the AMI Revenue Requirement was done at the request of PUC Staff. Updates included: 1) removal of tax gross-up on legacy meter retirements (would be included in the next ARP Reset Filing), and 2) Bonus Depreciation will be based on Section 3.02(2)(b) of Revenue Procedures 2011-26 (100% for assets in service 9/9/10 through 12/31/11 and 50% for assets in service pre-9/9/10 and post-12/31/11. *Regulatory Filings: Docket No. 2010-051II, ODR-05-04.*

7. *August 2012 Filing* - After informal discussions with Staff in the second quarter of 2012, it was agreed the Company would file an update to the revenue requirement and begin discussions again to find a resolution. Updates included: Update of carrying costs, update for actual severance costs that had been realized, update for transmission allocators and cost of capital, update for overheads, escalation, customer count, and update for actual costs realized. *Regulatory Filings: Docket No. 2010-051II.*

8. *March 2013 Filing* - Cost of Service Revenue Requirement for the twelve months ended 6/30/2014 containing actual deferred costs and savings through 12/31/12, and projected costs and savings through 6/30/14.[132]

[132] CMP Data Response: BRCS-001-011.

APPENDIX D: STAFF COMMENTS AND BLUE RIDGE RESPONSE

Staff Comments on Draft AMI Audit Report

1. AMI Project Costs and Savings

- Regarding page 9:
  - The draft if unclear as to the source of the Company's August 2012 calculation of $13.6M in net savings rather than $24.9M in net savings (see Attachment 1, Page 1 of 35, August 21, 2012). It follows that it is unclear what is intended by, "Blue Ridge believes the Company to have satisfactorily explained the variance between the net savings of the cost-benefit analysis method in filings from January 2010 to August 2012…"
    - **Blue Ridge**: We have modified the discussion in the report to consistently reflect the Company's one-year base savings amounts calculated using 2006 as base for years 2009-2013, and 2008 as base for years 2014 through 2032.
      (Changes made to pages 9, 17, 37.)

  - The draft is unclear on the source of the reduction from $127 million to $99 million.
    - **Blue Ridge**: The statement mentioning $99 million was taken from Order Initiating Management Audit, dated June 17, 2013, in Docket No. 2010-00051 (II), page 4. However, in order to maintain consistency in presentation, Blue Ridge has adjusted its discussion (as noted in the comment above) to reflect the Company's one-year savings amounts using years 2006 and 2008 as base years as mentioned.
      (Change made to page 9.)

  - The draft is unclear whether the significant variance related to the Customer Relation Savings of $17.5M is intended to refer to a difference between the Jan, 2010 and Aug, 2012 values or the difference between Aug, 2012 and Mar., 2013 values.
    - **Blue Ridge**: The $17.5 million refers to a difference between August 2012 and March 2013. Blue Ridge adjusted the report to provide clarity.
      (Change made to page 9.)

  - The draft is unclear regarding what is intended by the following:

    - "However, the Company's March 2013 cost of service revenue requirement was limited to costs and savings incremental to the level provided for in its 2012 tariffs." Staff is unclear what is intended by this as prior to July, 2013, all costs and savings associated with the AMI project were deferred and included in a deferral account, not reflected in rates or tariffs.
    - **Blue Ridge**: As described by the Company, the intent is that the March 2013 filing was to provide the 1-year revenue requirement impact of AMI (including incremental savings). Total costs and

related savings were reflected in that revenue requirement calculation. Blue Ridge adjusted the report accordingly for clarity. (Change made to page 9.)

- Regarding page 13: The draft report is unclear that the $523,000 and $1.4M values represent the average annual distribution portion of the revenue requirement.
    - o **Blue Ridge**: Blue Ridge clarified the point in the report and provided an appropriate footnote.
      (Change made to page 13.)

- Regarding page 15: The time study was ordered as part of the February 25, 2010 Order approving CMP's AMI program.
    - o **Blue Ridge**: Changed report wording to indicate that the time study was part of the Feb 2010 Order.
      (Change made to page 15.)

- Regarding page 16: It is unclear what is intended by the phrase, "[t]he report was collaborated by three FERC reports"
    - o **Blue Ridge**: Modified the statement to say, "As part of its support material for its 2009 report, the Company provided three reports developed by FERC on the AMI industry." This statement is also footnoted with CMP's response to BRCS-01-007, Attachments 32, 33, and 34.
      (Change made to page 16.)

- Regarding page 17: The basis for the Table 1 expected savings is unclear. It appears that the values reported as the savings for the period 2009 – 2013 correspond to a 1-year annual savings based on a 2006 base year. If this is what is intended, it should be clarified. It also appears that CMP's January 2010 filing included $207,946 in Cash Flow savings not included in this table. The basis for this exclusion should be noted. The source for the "Beginning 2014" is unclear (based on a cursory review, at least, Staff does not see this stream of values in the company's January, 2010 spreadsheet).
    - o **Blue Ridge**: As noted in response to Staff's first comment above, the savings mentioned are one-year savings on the basis of year 2006 (for forecasted years 2009 through 2013) and year 2008 (for forecasted years 2014 through 2032).
      Blue Ridge relied on the Company's response to BRCS-001-008 Attachment Page 4 for the information in this table. However, a cross check to the detail in BRCS 01-013 Attachment 4 shows the $207,945 to which Staff refers and which was missing from the response to BRCS-001-008. (We are asking the Company for clarification as to why this amount was left out.) With respect to the 2014 amounts, this column is using the 2008 amounts as base as shown in BRCS-001-013 Attachment 5. We understand this to be the basis of the 2014 ARP.
      (Change made to page 17.)

- What was the basis of the original FTE reduction of 126 (pg. 18)?
    - o **Blue Ridge**: 126 FTEs calculated from 110 FTEs and 31 part time/seasonal (estimated to be half FTE). Added explanation to the text.
      (Change made to page 18.)

- What caused the additional 14 FTEs to be added (pg. 19)?
  - **Blue Ridge**: The increase from 3 FTEs to 14 FTEs was stated by the Company to be for operational support.
    (Change made to page 19.)

- (pg. 19) Why does employee bumping lead to problem tracking positions eliminated? Given this difficulty, what is the basis of the 93 FTE reduction?
  - **Blue Ridge**: Removed this discussion because it did not contribute to conclusions.
    (Change made to page 19.)

- The draft is unclear about what is meant by "Differences in Forecast Period". Are the differences indicated in the Table on pg. 39 due to (1) changed assumptions for the March 2013 estimates compared to August 2012, or (2) use of a 1-year revenue requirement vs. 20-year future period or (3) both?
  - **Blue Ridge:** The differences in the column "Differences in Forecast Period" are for the use of a 1-year rev req vs. a 20-year future period that was adjusted by simply taking the 1-yr forecast and applying general inflation factors. We have altered the language on the preceding page to provide more clarity concerning the "Difference in Forecast Periods."
    (Change made to page 38.)

- It would be helpful if the Report could include a side-by-side comparison using a comparable calculation methodology of (1) the August 2012 estimated costs/savings (2) the March 2013 estimated costs/savings and (3) CMP's currently estimated costs/savings. To the extent this can be included, showing the differences by component (similar to the categories in the Table on pg. 39) would be helpful, as well as providing an explanation of the differences.
  - **Blue Ridge**: Table 1 was provided by the Company in response to Blue Ridge's similar request to re-cast the March 2013 filing using the same methodology as the August 2012 filing. (BRCS-002-011 supplemental). Blue Ridge was not provided information associated with the March 2013 filing to be able to do the comparative analysis suggested by Staff. The Company stated numerous times that comparing March 2013 to August 2012 is an "apples-to-oranges" comparison (see response to BRCS-002-011).

- (pg. 39) Portions of Table 1 not legible.
  - **Blue Ridge**: We have increased the table legibility.

- (pg. 39) Clarify what the Company included in "avoided costs". How do these avoided costs impact revenue requirements on a going forward basis?
  - **Blue Ridge**: Restated for clarification.
    (Change made to page 39.)

2. AMI Program Capabilities

- The draft is unclear with respect to the capabilities expected to be available by year-end 2014 and those not available until the new CMP billing system is operational. For example, what supply market pricing programs will the interim system changes support, and for what groups of CMP customers will the programs be available?

- **Blue Ridge**: At page 48, Blue Ridge states that "In interviews, the Company confirmed that all three of these will be addressed during this calendar year." All three refers to the bullet list right before the statement which include:
    - Critical Peak Pricing – expected by year end 2014
    - Hourly billing for large commercial and industrial customers can be supported manually
    - Capability Period tag values will be based on each customer's actual hourly AMI meter reading with the exception of accounts retaining legacy meters – 6/1/14

  With respect to what group of customers, at page 47, we state that 40-50 customers would be impacted by the dynamic pricing work around. With capabilities that will be available with the CMP system implementation, the Company stated that Meter Data Management System/Dynamic Pricing would be available when the system is implemented. From information provided by the Company (BRCS-008-009), the "Go-live" date is November 2014. Therefore the new capability should be available then. (Draft change at pages 10 & 48 to add statement about go live date – November 2014)

- The draft is unclear on the associated costs to support (1) the "interim" capabilities, i.e., those expected to be available by year-end 2014, and (2) the full capabilities envisioned by the Order, including dynamic pricing programs that are accessible by all customers.
    - **Blue Ridge**: On page 47-48 Blue Ridge identifies the CSS integration work costing $6.2 million, which includes $766,000 for the interim solution, $1.5m for the MDM upgrade, and $4.2 for the new MDM/Dynamic Pricing system.
      (No change to draft)

- Observation that costs for the capabilities related to market programs, e.g., dynamic pricing, may not have been included in original project scope, thus suggesting "no harm", does not address the following issues: (1) the extent to which the capabilities were assumed to be available with no significant incremental cost, e.g., using the existing billing system; and (2) the lost "time value of money" associated with consumer benefits from these programs being significantly delayed.
    - **Blue Ridge**: As discussed, Blue Ridge found that the Company's documents show that it did acknowledge the Commission's (and Staff's) concerns about the assumed capabilities. The report at page 49, states:

Blue Ridge also found that, based on its review including interviews, data requests, the Company's testimony in 2007-215, and subsequent filings, CMP had committed to provide supply side dynamic pricing options. One document in particular, ***CMP's AMI Project Execution Plan,***[133] *clearly states, "to enable electricity suppliers to create dynamic pricing options for customers."*[134] *Further, this plan states that one of the benefits of the AMI system would be "[a]n updated customer billing system to support new incentive rates that [sic]* ***expected from the Maine PUC and from third-party energy providers****.*[135]

Based on this information, there is little room to allow a "benefit of the doubt" that the Company's interpretation of what was intended at the outset of the implementation of AMI

[133] Provided in response to BRCS-001-002 Attachment 3
[134] Ibid. at page 6 of 28
[135] Ibid.

was different from what the Commission and/or Staff believed the Company promised. However, it is not clear in either the Project Execution Plan or the System Integrator work scope where this capability—dynamic pricing for suppliers—was addressed. Blue Ridge reviewed the system integrator RFP work scope and could not find where the capability to offer TOU pricing on the supply side was ever contracted out. Therefore, it is not clear that CMP actually included work steps to implement this function.

From our discussions of 24 Jan 14, we agreed that this language was sufficient to express Staff's concerns about the assumed capabilities.
With respect to the second point (lost opportunity for customer savings), Blue Ridge will add language to make that point.
(Draft page 11 and 49)

- The draft does not address the extent to which the "interim" solutions that CMP is developing to accommodate certain capabilities by Q4 2014 require manual processes or "workarounds" by CMP and/or suppliers that may limit or preclude participation by suppliers or customers.
    - **Blue Ridge**: Please see page 47 where we state, "In response to Staff's concern, CMP implemented a manual process to address the requirement of "back office and billing systems capable of billing T&D and supply on a TOU basis." In discussions with Staff, the Company proposed manual billing for standard offer, large industrial/commercial customers as an alternative to modifying the existing billing system. About 40-50 customers are impacted by the dynamic pricing option. An agreement between Staff and the Company was reached recognizing that an interim manual solution was acceptable and a more efficient solution for the small volume of standard offer customers considering the remaining limited life of the current billing system. Rolling out a full scale hourly pricing option will be addressed when CMP designs the functional requirements for a new billing system.[136]"
      Please indicate whether this addresses Staff's concern.
- The report should discuss and assess the effect that the cost of the new CMP billing system has on the overall AMI project cost/benefit outlook.
    - **Blue Ridge**: The Company has repeatedly said that it has none.

- The report should specify how total actual costs (incurred to date and forecasted) to implement dynamic pricing compare to the estimates provided by the Company (pg. 53) both on an interim and long term basis.
    - **Blue Ridge**: The project cost information does not break down to that level of granularity.

- The report should address to the extent there are costs that are/will be incurred to implement the interim solution that would be unnecessary if the new billing system were in place. Also, are there systems being put in place for the interim solution that will be superseded by the new billing system.
    - **Blue Ridge**: The draft at page 47 identifies the $766,000 as the interim solution and $1.5m for the MDM upgrade. These would be the costs that are incurred for the interim solution. It is our understanding that these costs will be gone once CR&B is up.

[136] CMP Data Response: BRCS 008-011.

APPENDIX E: CMP COMMENTS AND BLUE RIDGE RESPONSE

CMP Suggested Factual Corrections to the Draft AMI Audit Report

CMP provided the following suggested factual corrections to the Draft Report.

1. The most important correction addresses the fourth topic covered in the Draft Report: AMI Program Capabilities. The Commission's July Order initiating this audit directs the auditor to determine:

    > Whether CMP has employed prudent and reasonable management to ensure that the AMI and related systems have the capabilities envisioned by the Commission at the time that the AMI audit was approved.

    The February 2010 Order approving CMP's AMI program did not include critical peak pricing (CPP) as a required system capability for which the Company was responsible in initially developing and implementing its AMI system. Similarly, the July 2013 Order initiating this audit, references that February 2010 Order and again lists the system capabilities that were envisioned by the Commission when it approved CMP's AMI project. It is those capabilities that the PUC requested Blue Ridge to audit. Importantly, CPP was not part of the initial capabilities identified in the Commission's July 2010 Order. The CPP requirement resulted from discussions between the parties and staff from 2010 through February 2012 as reflected in the Commission's March 20, 2012 Order in Docket No. 2010-132. Accordingly, it is factually wrong to suggest that CPP was a system capability included at the time the AMI system was approved; therefore it should not be included in the audit report as a requirement that was not met. The CPP requirements ordered by the Commission in March 2012 are simply beyond the scope of the audit report.

    > **Blue Ridge Response**: Blue Ridge has reviewed the Company's comments here and has re-reviewed the contemporaneous documentation. Based on that review and the facts that are contained within those documents, Blue Ridge respectfully disagrees with the Company's position and suggested factual changes related to the capabilities section of the report.
    >
    > First, with respect to the scope of the audit, Blue Ridge took direction from the Commission on the scope of the project, which, as the Company noted, included "whether CMP has employed prudent and reasonable management to ensure that the AMI and related systems have the capabilities envisioned by the Commission at the time that the AMI system was approved."[137] Therefore, the scope clearly included the AMI capabilities that the Commission believed were included in its February 2010 order. In consultation with MPUC Staff during the audit kick-off process, Staff clarified each of the four scope areas, including the capabilities area, to include the dynamic pricing functionality that is the subject of this section. In addition, during interviews with the Company, Blue Ridge questioned key Company personnel involved with the project's pre-planning and approval about the AMI capabilities. There were no objections at that time to discussing missing functionality/capabilities.

[137] The Company's comments incorrectly refer to "AMI audit was approved".

Second, Blue Ridge found that the Company "confirmed that both of these capabilities[138] will be addressed during this calendar year. Therefore, Blue Ridge found that the Commission's and Staff's concern is based in fact. Nothing that the Company has provided Blue Ridge through the audit process suggests otherwise. The Commission and Staff expected dynamic pricing available for all participants in the energy market, i.e., residential, small and large commercial, and industrial, and competitive energy providers - supply." In support of this statement, Blue Ridge offers the following documentation that forms the foundation of our conclusion.

- Docket 2007-215, Testimony of Mary Elizabeth Nowack Cowan dated May 1, 2007, on behalf of Central Maine Power. In this document the Company's witness makes the following statement at Page 44, Lines 1-7:

  "A CPP supply price program could be offered on a voluntary basis to CMP's customers once AMI is in place. The program can have either a basic TOU foundation or a flat rate foundation (as CMP's standard offer supply customers have today) with very high peak pricing during specified periods of system need as required. Customers who reduce usage during the critical peak periods will see lower bills as a result of lower energy costs and lower installed capacity ("ICAP") costs." **[emphasis added]**

  Witness Cowan then proceeds to provide estimates of potential savings for customers who avail themselves of Critical Price Peaking Supply Programs of $307,000 to $614,000. She then concludes:

  "There are many other demand response programs that may be offered to optimize the use of the AMI platform; the Company selected these two programs as examples due to the amount of market information available from other companies who have pursued such initiatives."[139]

- Docket 2007-215, Rebuttal Testimony of Mary Elizabeth Nowack Cowan dated November 9, 2007. In this document Witness Cowan states:

  "Since its May 1 filing, the Company has continued to study the various ways CMP customers could enjoy AMI-enabled demand response benefits. As a result of this additional analysis, the Company has now examined two potential voluntary programs that could be implemented with CMP's proposed AMI system. **A Critical Peak Pricing ("CPP") Supply Program was presented in Beth Nowack Cowan's Direct Testimony;** since May, a Peak Time Rebate ("PTR") Supply Program has also been analyzed. Both are examples of price-based demand response initiatives that require an AMI platform. **With AMI in place, many varieties of price-based demand response programs could certainly be offered by competitive energy providers in Maine. Such programs could also be offered by Standard Offer Providers in Maine under today's existing rules. [Emphasis Added]**

  Blue Ridge acknowledges that Witness Nowak-Cowan testified that the Company's billing system was "limited in its ability to calculate and produce customer bills for some of the more complex structures that would be enabled

---

[138] Referring to Critical Peak Pricing – expected by year end 2014 and hourly billing for large commercial and industrial customers can be supported manually
[139] Docket 2007-215 Nowack-Cowan Testimony at Page 43, Lines 16-19

by AMI."[140] In addition, she stated, "This system would require modification or replacement should suppliers seek to offer enhanced pricing programs to their customers and bill through CMP."[141] However, she goes on to state, "**CMP will provide this billing functionality to support the marketplace's enhanced demand response pricing programs coincidental with the with the completion of the AMI deployment** and is currently assessing the costs associated with the billing system upgrade."[142] [**emphasis added]**

In addition to this 2007 testimony, Blue Ridge relied upon other documented facts in support of its conclusion that the Commission and Staff's understanding that dynamic pricing including CCP would be included in the AMI functionality. These include:

- From BRCS-003-001 Attachment 1 – [Confidential Document] – **Project Plan** dated August 6, 2009. Section H. **Dynamic Pricing Implementation** states, "The MPUC will initiate a proceeding to consider and develop time-differentiated standard offer service and other dynamic pricing products to maximize the utility of CMP's AMI platform (See Attachment 2). Although the MPUC is responsible for the definition and acquisition of the standard offer electricity supply with dynamic pricing, CMP will support the implementation through the AMI network by providing customer usage rate information, customer service and billing rates. **Once implemented, dynamic pricing will be available to 100% of CMP's customers. The plan is to have dynamic pricing available soon after deployment of the AMI project."**[143] [**emphasis added]**
- CMP's Testimony (dated January 19, 2010) in Response to Commission Order dated July 28, 2009. On page 4, the Company states, "CMP's proposed AMI Project will support AMI, dynamic pricing and distribution automation applications, and provides a future-proofed flexible framework to support enhanced Smart Grid functionality. CMP's AMI project will provide the same level of fundamental benefits to all CMP's 600,000 plus customers throughout the 11,000 square mile service area.[144]

Therefore, from documentation in 2007 to 2009 and then into 2010, the expectation had been established that dynamic pricing, including critical peak pricing, would be part of the functionality of the Company's proposed AMI. Based on these documented facts, Blue Ridge stands by our conclusion that the Company included CPP as a dynamic pricing option with its AMI proposal.

2. CMP implemented all requirements that were defined within the AMI program timeframe (2010-2012)

In fact, CMP implemented all requirements that were defined within the AMI program timeframe (2010-2012). CMP has completed all of the required billing and system capabilities from the February 2010 order based on the known requirements up to 2012

[140] Ibid. at page 45, Lines 1-3
[141] Ibid. at page 45, lines 3-4
[142] Ibid. at page 45, lines 4-7
[143] BRCS-003-001 Att. 1 page 14 of 40 (Confidential Document)
[144] BRCS-001-029 Att. 3 Page 5 of 15 (Confidential Document)

which CMP considers the end of the AMI program implementation. (See table 1 for more detail on status and delivery dates for the capabilities).

Table 1: February 2010 Dynamic Pricing Requirements as included in the audit scope

	Dynamic Pricing System Capability	Status/Delivery date (to confirm)
1.	Back office and billing systems capable of billing, both transmission and distribution (T&D) and supply, on a TOU basis.	Completed – 12/1/2012
2.	These systems will be designed to allow for time periods that differ between T&D and supply	CMP implemented the T&D definition of TOU on 12/1/2013. In gathering further dynamic pricing requirements and as requested by Staff, CMP reached out to suppliers in May 2013 to determine supplier requirements for TOU periods. Suppliers requested the ISO-NE market definition of TOU. This updated TOU requirement will be implemented by YE2014.
3.	These systems will allow hourly billing for large commercial and industrial customers.	This capability can be supported manually; as agreed by Staff and CMP as noted in audit; there is currently no Commission requirement to utilize this capability.
4.	The billing and other back office systems will allow loads to be settled in the ISO-NE market systems for all customers based on actual hourly loads rather than load profiles	Completed – 5/1/2013
5.	Allow ICAP tags for all customers to be based on actual metered load in the applicable hour, rather than the load profile.	The system was capable of producing capacity tags based on hourly data and according to the ISO-NE market rules by 5/1/2013. For the upcoming annual Capability period, 6/1/2014, CMP will develop individual customer tag values based on the hourly AMI data used for wholesale market settlement during the 2013 ISO-NE system peak.
6.	The billing and back office systems will allow for multiple standard-offer products within a given standard offer class	Completed – 12/1/2012 for TOU

As the Draft Report acknowledges, because the dynamic pricing discussions between CMP and the Commission staff are ongoing, the BRCS's assessment does not necessarily have the most current information. CMP provides the following information to help clarify these issues. Since the March 20, 2012 issuance of the Dynamic Pricing Order in Docket No. 2010-132, CMP has worked with Staff to define dynamic pricing requirements. Based on discussions with Staff, CMP delivered a T&D defined TOU program in December 2012. CMP continued to work with Staff to further define requirements for new programs and enhancements to the TOU program. In May 2013, CMP and Staff agreed to utilize the ISO-NE market definition of TOU periods. On January 29, 2014, CMP and Staff reached agreement on dynamic pricing business requirements and the Staff filed a Notice Regarding Discussion on AMI Implementation regarding the agreed dynamic pricing requirements for CPP and market-defined TOU (see attached Notice). CMP is now developing a cost and schedule estimate for Staff review based upon the agreed business requirements. Assuming agreement is subsequently reached on a suitable cost and schedule, CMP expects to implement the two dynamic pricing programs by year end 2014.

In the original Commission approval process for AMI, CMP did commit to provide supply side dynamic pricing capabilities. However, this commitment was conditioned on obtaining sufficient guidance from competitive suppliers and the Commission Staff regarding program design and the resulting business requirements for the desired dynamic pricing products. As indicated above, this process has been ongoing and is not yet complete.

> **Blue Ridge Response:** See Blue Ridge's previous comments to #1.

3. CMP can support the large C&I customers hourly billing but there is currently no MPUC demand for these programs.

CMP can manually support hourly billing for a reasonable number of large C&I customers; CMP and Commission Staff jointly agreed that this is the most cost effective means to deliver this solution prior to replacement of CMP's current billing system. There is currently no MPUC requirement to utilize this capability.

> **Blue Ridge Response:** See Blue Ridge's previous comments to #1.

4. ICAP Tag Values

As noted in the table above, the capability to determine Capacity obligation values ("ICAP Tags") using individual customer AMI data was implemented on 5/1/2013. However, the determination and application of ICAP Tags is an annual process, conducted for each Capability Period, commencing on June 1 of each year. In accordance with ISO-NE procedures, Tag values are to be determined based upon the hourly customer usage during the prior annual system peak hour, as determined by the customer's energy usage reported for wholesale energy market settlement. Accordingly, for the Capability Period commencing 6/1/2013, tag values for most customers were determined using the profiled loads used in the 2012 energy market settlement process. The June 2014 Capability Period will be the first opportunity to apply the new ICAP tag determination process using AMI data, despite having this capability in place since May 2013.

> **Blue Ridge Response:** Blue Ridge understands the Company's point in that the capability was implemented although the opportunity for employment of the capability will not occur until June 2014. Blue Ridge has modified the report accordingly.

5. Dynamic Pricing Costs

CMP implemented dynamic pricing system changes based on the known requirements through the 2010-2012 AMI program implementation period. The dynamic pricing costs that were included in the program costs support the 2010-2012 defined dynamic pricing functionality, including AMI-based ICAP tags as well as a residential TOU program based on T&D TOU periods delivered in 2012. These costs were included in the March 2013 AMI revenue requirement. Estimated costs to implement additional dynamic pricing requirements have been included in the ARP2014 revenue requirements in Docket No. 2013-00168.

Blue Ridge Response: See Blue Ridge's previous comments to #1.

6. Supply-side benefits

Customers are currently realizing supply side benefits from the capabilities that have already been implemented, and will continue to achieve additional benefits from these capabilities, including ICAP tags and TOU pricing. With respect to hourly billing capabilities for large commercial and industrial customers, there is currently no MPUC demand for this capability and therefore there is no "missed" supply-side benefit. In the case of CPP, pending Staff approval of CMP's proposed cost and schedule, this benefit will be implemented in 2014, based on the defined requirement completed as of January 2014. The supply-side benefits realized through CPP should be considered one of the continued future benefits achieved by AMI.

Blue Ridge Response: See Blue Ridge's previous comments to #1.

7. Other Corrections

Pages 6 and 15 – Update the correct number of data requests, given that we answered one on Monday: "70 DRs in 8 submittal sets" should be "71 DRs in 9 submittal sets."

Blue Ridge Response: Blue Ridge agrees and updated the report accordingly.

Page 8, paragraph 5 – added 'capital' to before costs. The sentence should read:

The Company originally estimated that the *capital* costs to complete the AMI program would be $163.8million.

Blue Ridge Response: Blue Ridge agrees and updated the report accordingly.

Page 9, paragraph 8, the interim billing solution, and not the full CRM&B billing solution, will be completed by the end of 2014.

Blue Ridge Response: Blue Ridge agrees and updated the report accordingly.

Page 9, under the numbered list of capabilities not yet in place, remove item 3, as the capability to determine ICAP tags has been in place since May 2013.

Blue Ridge Response: Blue Ridge agrees and updated the report accordingly.

Page 18 – Clarification of the definition of major and minor storms and related savings – incremental costs over $150,000 (this was outlined in BRCS-001-013 Attachments 3 and 4).

Second paragraph should read: "Storm Costs – CMP anticipated a storm cost reduction of 10% of incremental costs for all storms with incremental costs over $150,000. These cost savings include such items as overtime, meals, contractors, and some payroll taxes

Blue Ridge Response: Blue Ridge agrees and updated the report accordingly.

Page 19 – On bullets 2 through 4 and the first full paragraph, included is clarifying language on the treatment of grant money.

Suggested language for Bullets 2 through 4 and first paragraph:

2. The initial total actual capital cost of the project was $167.18 million.
3. The Company was responsible for half the project costs eligible for reimbursement ($167.2/2) or approximately $83.6 million.
4. The Company was reimbursed from the DOE for half of the net book value of the legacy meters (total subject to DOE reimbursement $191.7 million less original project estimate $163.8 million) / 2 = $14 million, which was the original estimate; actual net book value of legacy meters was $10.8 million.

Therefore, the unreimbursed cost in total was approximately $94.4 million ($83.6 million plus $10.8 million).

Blue Ridge Response: Blue Ridge agrees and updated the report accordingly.

Page 30, paragraph 3 –

add 'capital' to before costs. The sentence should read:

The Company originally estimated that the *capital* costs to complete the AMI program would be $163.8 million…

Blue Ridge Response: Blue Ridge agrees and updated the report accordingly.

Page 48 – as noted on Page 45, the capability to create capacity tags based on AMI hourly data was delivered on 5/1/2013. As correctly noted on the last bullet on page 46 and the top of page 47, the system was capable of producing capacity tags based on hourly data and according to the ISO-NE market rules, the tags for 6/1/2013 were produced based on profiles as the load for that peak season was settled based on profiles. For the upcoming Capability Period beginning 6/1/2014 CMP will develop individual customer tag values based on the AMI data used for settlement during the 2013 ISO-NE summer peak load hour. The date should also be corrected on p. 45 under 'Measuring and storing the TOU peak demands of each customer as necessary for billing…"

Blue Ridge Response: Blue Ridge agrees and updated the report accordingly. However, Blue Ridge also noted in a footnote that while the capability had been delivered, it will not be employed until June 2014 due to ISO-NE market rules.

Page 49, paragraph 5 –the issues will be addressed with an interim billing solution in 4Q14.

Blue Ridge Response: Blue Ridge agrees and updated the report accordingly.

Chapter 3
Ministry of Energy

Section
3.11 Smart Metering Initiative

Background

In April 2004, the Ontario government announced a plan to reduce energy consumption in the province by creating a culture of conservation. One aspect of the plan was the provincial Smart Metering Initiative (Smart Metering)—the first and the largest smart-meter deployment in Canada—to install new "smart" electricity meters throughout the province to measure both how much and when electricity is used. The new meters would make it possible to introduce time-of-use (TOU) pricing to encourage ratepayers to shift their electricity use to times of lower demand. Smart Metering reflected the intention of the Ministry of Energy (Ministry) to manage demand for electricity in Ontario so as to more efficiently use existing power-generating capacity in the province while reducing reliance on out-of-province power purchases.

The Ministry set aggressive Smart Metering implementation targets, including an interim goal of 800,000 smart-meter installations by 2007 and complete coverage for all residential and small-business ratepayers by 2010. Entities involved in Smart Metering included the Ministry, the Independent Electricity System Operator (IESO), the Ontario Energy Board (OEB) and Ontario's 73 local electricity distribution companies, including Hydro One. Key roles and responsibilities of each entity are summarized in **Figure 1**, while **Figure 2** shows key events in implementation of Smart Metering.

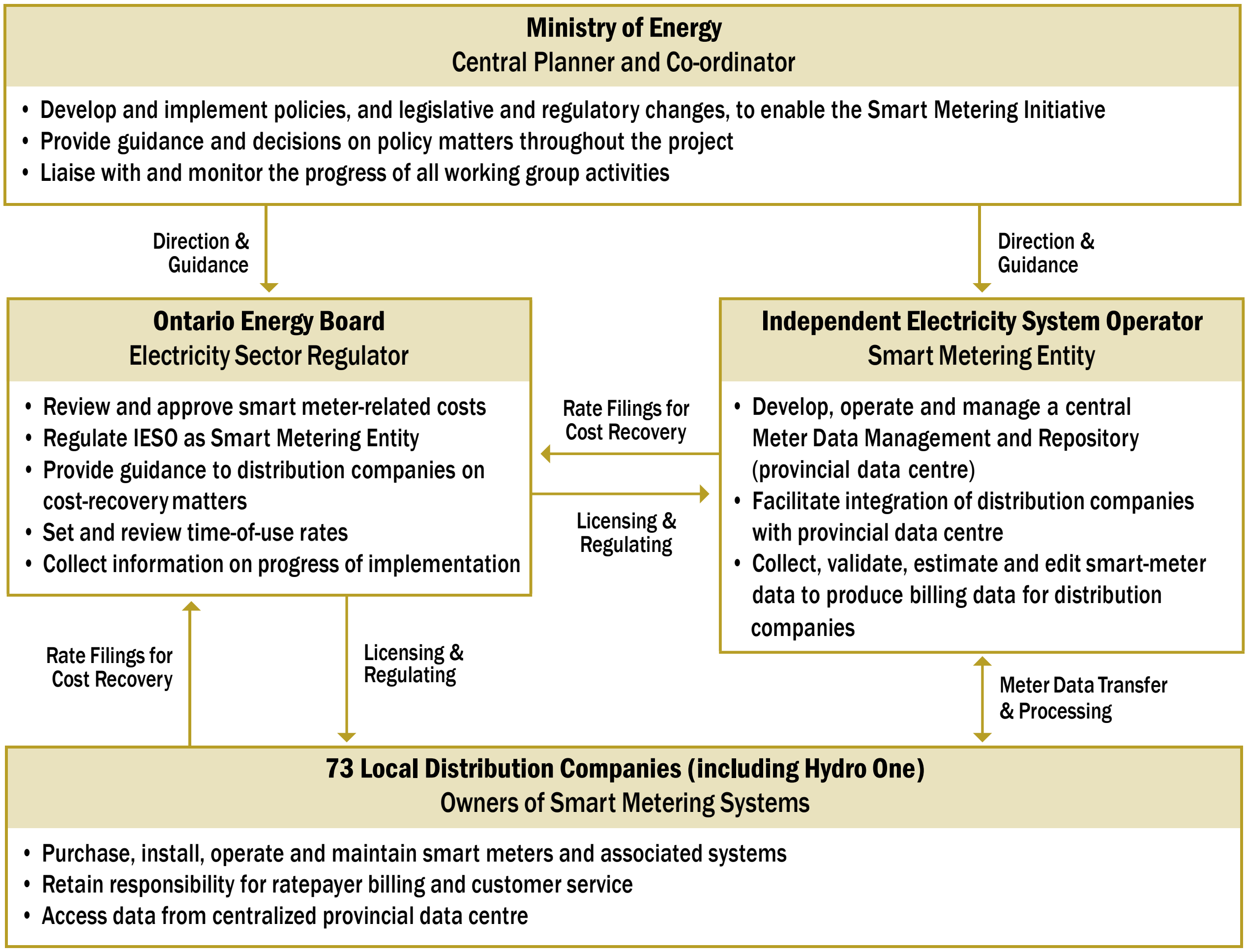
As of May 2014, there were about 4.8 million smart meters installed across Ontario, covering almost all residential and small-business ratepayers, and accounting for 45% of all electricity consumed in the province (large commercial and industrial users account for the remaining 55%). Smart meters resemble conventional meters, but differ with respect to how consumption data is displayed, measured, recorded and communicated, as illustrated in **Figure 3**.

Smart meters are the base infrastructure for developing a smart grid, which is the application of information and communications technology to improve the functioning of the electricity system and optimize the use of natural resources to provide electricity. In the *Electricity Act, 1998*, the smart grid and its objectives are set out as the information-exchange systems and equipment used together to improve the flexibility, security, reliability, efficiency and safety of the power system, particularly for the purposes of increasing renewable generation; expanding provision of price information to electricity customers; and enabling innovative energy-saving technologies.

Under TOU pricing, electricity rates charged are highest during the day, but drop at night, on

Figure 1: Key Roles and Responsibilities of Entities Involved in the Provincial Smart Metering Initiative

Prepared by the Office of the Auditor General of Ontario



weekends and holidays. The combination of smart meters and TOU pricing was expected to encourage electricity conservation and reduce demand during peak times by providing ratepayers with information and incentives to manage their electricity use by:

- moving consumption from peak to off-peak times (for example, running the dishwasher or dryer at night rather than in the afternoon); and
- reducing consumption during peak times (for example, setting the air conditioner a few degrees warmer on summer afternoons).

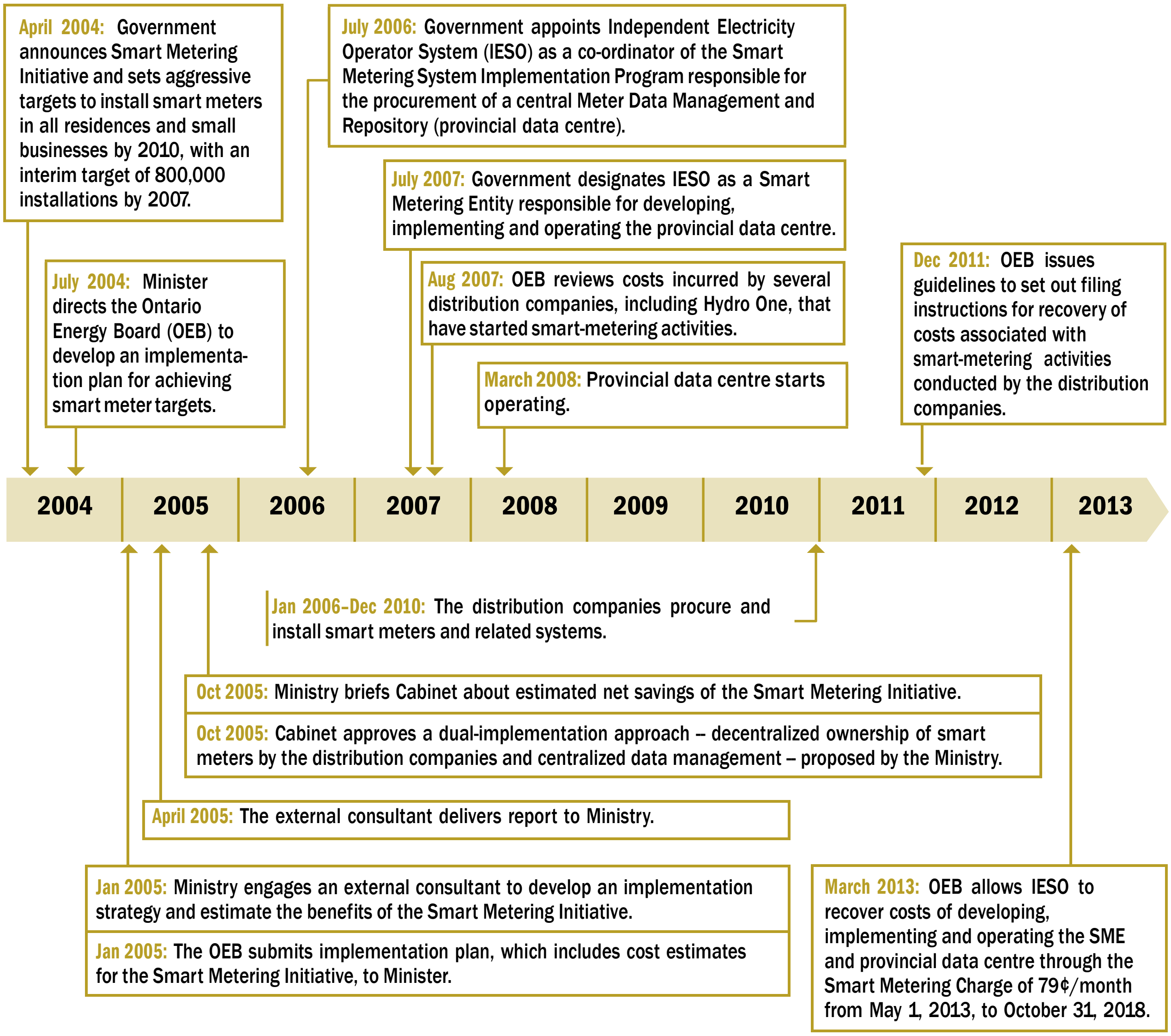
The Ministry set several targets to reduce peak electricity demand: a 1,350MW reduction by 2007; a further 1,350MW drop by 2010; and an additional 3,600MW reduction by 2025. The potential reduction in peak demand was intended to lighten the burden on electricity infrastructure, which in turn could reduce the need to build new power plants, expand existing ones, or enter into additional power-purchase agreements. It was also expected to help bring about the closing of coal-fired power plants, which were typically only used during periods of peak demand.

Audit Objective and Scope

Our audit objective was to assess whether effective systems and procedures were in place to:

Figure 2: Timeline of Key Events Relating to Implementation of the Provincial Smart Metering Initiative

Prepared by the Office of the Auditor General of Ontario



- ensure that the Smart Metering Initiative (Smart Metering) was planned, implemented and managed economically and efficiently, and in compliance with applicable policies and requirements; and
- measure and report on whether the objectives of Smart Metering were met in a cost-effective way.

Senior management at the Ministry of Energy (Ministry), the Independent Electricity System Operator (IESO) and the Ontario Energy Board (OEB) reviewed and agreed to our objective and associated audit criteria. We conducted this audit from October 2013 to May 2014.

In conducting our audit, we reviewed applicable legislation, regulations, policies, studies and other documents; analyzed electricity consumption and billing data; and interviewed appropriate staff at the Ministry, the IESO and the OEB. We surveyed 60 of Ontario's 73 distribution companies, with a response rate of over 70%, and interviewed staff from the remaining 13 distribution companies, including Hydro One, the only distribution company owned by the province. **Appendix 1** contains the

Figure 3: Comparison of Smart Meter and Conventional Meter
Prepared by the Office of the Auditor General of Ontario

	Smart Meter	Conventional Meter
		
Display	Digital meter with numerical display	Analog meter with spinning dials
Measure	How much and when electricity is used (typically hourly with date and time stamp)	How much electricity is used over a billing period (typically one or two months)
Recording	Automated meter reading: meters send data electronically to distribution companies through a wireless network*	Manual meter reading: distribution company staff physically visit ratepayer premises to record data
Communication	Two-way communication between meters and distribution companies*	No communication capability
Pricing	Time-of-use pricing (a three-tiered rate structure: on-peak, mid-peak, and off-peak) to reflect changing electricity costs throughout the day	Two-tiered pricing, with one rate applied to consumption up to a threshold and a second rate for electricity consumed in excess of this threshold

* See Figure 11 for data flow between the distribution company's smart-metering system and the IESO's provincial data centre.

questions posed to the distribution companies we interviewed and surveyed, and summarizes their responses. We also reviewed data and studies from the Ontario Power Authority, which has been involved in co-ordinating and assessing province-wide energy conservation efforts, including time-of-use (TOU) pricing enabled by smart meters. As well, we met with the Electricity Distributors Association, which represents all distribution companies across the province. In addition, we conducted research on smart-metering programs in other jurisdictions to identify best practices, and we engaged on an advisory basis the services of an independent expert with knowledge of smart metering.

Summary

The Ontario government's Smart Metering Initiative (Smart Metering) is a large and complex project that required the involvement of the Ministry of Energy (Ministry), the Ontario Energy Board (OEB), the Independent Electricity System Operator (IESO), and 73 distribution companies, including Hydro One. Our audit found that Smart Metering was rolled out with aggressive targets and tight timelines, without sufficient planning and monitoring by the Ministry, which had the ultimate responsibility to ensure that effective governance and project-management structures were in place to oversee planning and implementation. As yet, many of the anticipated benefits of Smart Metering have not been achieved and its implementation has been much more costly than projected.

Our report highlights the difficulties that have been experienced in rolling out Smart Metering, which represents an initial step towards creating a smart grid—using information and communications technology to improve the functioning of the electricity system and optimize the use of natural resources to provide electricity. We hope that lessons learned from implementing smart meters can be applied to the government's ongoing efforts to develop a smart grid in Ontario.

Some of our key observations related to Smart Metering are as follows:

Decision to Mandate Smart Metering Not Supported by Appropriate Cost-benefit Study

The government announced Smart Metering in April 2004, and shortly thereafter the Minister of Energy issued a directive to the OEB under the *Ontario Energy Board Act, 1998*. The directive required the OEB to develop an implementation plan to achieve the government's targets of 800,000 smart-meter installations by 2007 and complete coverage for all residential and small-business ratepayers by 2010. The Ministry did not complete any cost-benefit analysis or business case prior to making the decision to mandate the installation of smart meters. This is in contrast to other jurisdictions, including British Columbia, Germany, Britain and Australia, which all assessed the cost-effectiveness and feasibility of their smart-metering programs. As well, even though the electricity market in Ontario continued to change, the Ministry never adjusted the smart-meter implementation plan.

Subsequent Cost-benefit Study Flawed

After the government announced the rollout of Smart Metering in April 2004, the Ministry prepared a cost-benefit analysis of Smart Metering, and submitted it to Cabinet in October 2005. However, the analysis was flawed; its projected net benefits of approximately $600 million over 15 years were significantly overstated by at least $512 million because it excluded an annual net increase in the projected operating costs of distribution companies. In other words, the projected net benefits should have been reflected as only $88 million over 15 years.

Smart Metering Costs to Date Exceed Projected Costs and Benefits

The Ministry has neither updated the projected costs and benefits of Smart Metering, nor tracked its actual costs and benefits, to determine the actual net benefits being realized. Up to the end of 2013, our analysis shows that total smart metering-related costs incurred only by the distribution companies had already reached $1.4 billion—well in excess of the Ministry's initial total projected costs of $1 billion. When costs of the Ministry, the OEB and the IESO are included, we noted that total costs relating to implementation of Smart Metering had reached almost $2 billion at the time of our audit. Additional costs are expected in the future because some distribution companies had not yet incorporated all of their implementation costs into their charges to ratepayers (these additional costs will be subject to OEB review and approval). As well, the benefits of Smart Metering in reducing distribution companies' operating costs and reducing electricity bills to ratepayers were so far limited: Of the distribution companies we consulted, 95% said they realized no savings and their operating costs actually rose, and over half said they received a high volume of ratepayer complaints about "increased bills with no savings."

Significant Smart Metering System Development and Integration Challenges Encountered

In other jurisdictions, mass deployment of smart meters was carried out by only a few distribution companies, or even just one. The challenge in Ontario was that 73 distribution companies were each separately responsible to purchase, install, operate and maintain smart meters, as well as to bill ratepayers. This made it difficult to ensure a cost-effective implementation of Smart Metering. Three-quarters of the distribution companies we consulted ranked data management and system integration as one of the top three challenges of Smart Metering, and 83% said it was difficult and costly to integrate their systems with the provincial data centre. There have been many system upgrades, including changes made in order for Ontario to comply with Measurement Canada's billing disclosure requirements after smart meters were installed.

Peak-demand Reduction Targets Not Met

The purpose of Smart Metering was to enable time-of-use (TOU) pricing, which was expected to reduce electricity demand during peak periods. The Ministry set several targets to reduce peak electricity demand (a 1,350MW reduction by 2007, a further 1,350MW drop by 2010, and an additional 3,600MW reduction by 2025). However, the initial target of reducing peak demand by 1,350MW was irrelevant to Smart Metering anyway because it was supposed to be achieved by 2007, three years before full installation of smart meters was to be completed. With respect to the second target of an additional 1,350MW reduction by 2010, peak electricity demand did not fall, but actually rose slightly by about 100MW between 2004 and 2010.

Ontario's Surplus Power Exported to Other Jurisdictions at Less than Cost

The reduction of electricity demand during peak times was intended to delay the need to expand power-generating capacity in Ontario, along with the related costs. In the decade since the Ontario government announced Smart Metering, peak demand has remained essentially unchanged, but the Ministry has approved significant increases in new power generation, such as renewable energy, creating power surpluses in Ontario. The overall financial impact has been that other jurisdictions are able to buy this surplus power from Ontario at a price considerably lower than what it actually cost Ontario to produce this power. The total cost of producing the exported power was about $2.6 billion more than the revenue Ontario received from exporting that power between 2006 and 2013.

Electricity Billing Amounts Varied by Distribution Company

Ratepayers pay different amounts for the same power usage depending on where they live in Ontario, mainly due to different delivery costs of the 73 distribution companies. For example, a typical residential electricity bill could vary anywhere between $108 and $196 a month, mainly due to the variation in delivery costs ranging from $25 to $111 a month charged by different distribution companies to ratepayers. Implementation of Smart Metering significantly impacted the costs for each of the distribution companies, which chose different smart meters and IT solutions for their in-house systems. The cost per meter therefore varied with each distribution company, ranging from $81 per meter to $544 per meter, depending mainly on geography and the amount of upfront costs. For example, Hydro One, the only distribution company owned by the province, incurred significant costs to implement its smart-metering project. By the end of 2013, Hydro One accounted for $660 million, or almost 50%, of the $1.4-billion implementation costs incurred by all 73 distribution companies. However, it installed 1.2 million smart meters, which represented only about 25% of the 4.8 million smart meters installed in Ontario.

Of the $660 million spent by Hydro One, more than $125 million went to a private-sector vendor with whom it signed multiple contracts for services, such as system integration and project management, and approved a number of change orders. Hydro One selected this vendor based on several criteria, including price. However, pricing evaluation was not based on the overall contract cost. Hydro One explained the contract cost could not be fixed due to the "unknown nature of all the business requirements at the time of the Request for Proposal (RFP)." Granting a contract through the RFP process without acquiring enough knowledge about the business requirements would lead to risks of significant cost increases due to change orders.

Time-of-use (TOU) Pricing Model Has Had Minor Impact on Reducing Peak Demand

Smart Metering was undertaken to enable the introduction of time-of-use (TOU) rates to encourage people to shift power use to Off-Peak periods. However, TOU rates and periods may not be designed effectively to reduce peak demand as intended. Specifically:

- The difference between the On-Peak and Off-Peak rates has not been significant enough to encourage a change in consumption patterns. When TOU rates were introduced in 2006, the On-Peak rate was three times higher than Off-Peak; by the time of our audit, that differential had fallen to 1.8 times, due to significant increases in the Global Adjustment, another component of electricity bills in Ontario. In particular, the Off-Peak rate increased the most, by 114%, while On-Peak increased the least, by 29%. As a result, the difference between On-Peak and Off-Peak rates has narrowed, thus undermining TOU pricing as an incentive for ratepayers to shift power use to Off-Peak periods.
- The distribution of On-Peak, Mid-Peak and Off-Peak periods does not fully reflect actual patterns of electricity demand. In particular, in response to amendments to Ontario Regulation 95/05, the OEB moved the start of Off-Peak in 2010 from 9 p.m. to 7 p.m. on weeknights, making the early evening hours of 7 p.m. to 9 p.m. Off-Peak, even though demand at those times is high.

In 2013, separate studies released by the Ontario Power Authority and the OEB indicated that TOU pricing had a modest impact on residential ratepayers, reducing their peak demand by only about 3%, but a limited or unclear effect on small businesses, and none at all on energy conservation. Our review also found that:

- Of about 1.8 million ratepayers on TOU rates that we reviewed, only 35% of residential ratepayers and 19% of small businesses reduced their consumption during On-Peak periods, while a majority of them (65% of residential and 81% of small businesses) did not.
- About 77,000 ratepayers with smart meters paid set rather than TOU rates because they signed fixed-price contracts with electricity retailers, who do not charge based on time of use. Consumption patterns of retail and TOU ratepayers were about the same, suggesting that TOU pricing provided no more incentive to change usage behaviour than retail contracts.

Significant Impact of Global Adjustment on TOU Rates Not Transparent to Ratepayers

The Electricity Charge on ratepayer electricity bills is composed of two parts: the electricity market price and the Global Adjustment, added to the market price mainly to cover the guaranteed prices paid to contracted power generators in Ontario. From 2006 to 2013, the Global Adjustment increased almost 1,200%, while the average market price actually dropped 46%. The impact of the Global Adjustment has been significant on ratepayer electricity bills as follows:

- The total Global Adjustment paid by Ontario ratepayers has grown from $654 million in 2006 to $7.7 billion in 2013. More contracted generators, especially producers of higher-priced renewable power, will soon be coming online, so the total Global Adjustment is expected to increase even more. Between 2006 and 2015, the 10-year cumulative actual and projected Global Adjustment stands at about $50 billion, equivalent to almost five times the 2014 provincial deficit of $10.5 billion. In essence, the $50 billion is an extra payment covered by ratepayers over and above the actual market price of electricity.
- The vast majority of residential and small-business ratepayers pay for electricity based on the three TOU rates—Off-Peak, Mid-Peak and On-Peak—which were seen as critical in encouraging ratepayers to shift power use to times of lower demand. The Global Adjustment now accounts for about 70% of each of

the three TOU rates. While the Global Adjustment has increased significantly and accounts for a substantial proportion of TOU rates, its impact is not transparent to ratepayers because it is embedded in TOU rates and does not appear as a separate line on most electricity bills (the Global Adjustment appears separately only on bills of those ratepayers who have signed contracts with electricity retailers, who do not offer TOU rates).

Ratepayer Complaints Stemmed from Time-of-use (TOU) Rates and Billing Errors

Many distribution companies did not track or log the nature or type of complaints they received. They were therefore unable to quantify the volume of complaints they received before and after smart-meter implementation; nor could they separate smart meter-related concerns from billing-system issues. Without proper tracking and monitoring of ratepayer concerns, key information could not be collated to identify and resolve common or recurring problems on a timely basis. Those distribution companies that did track complaints found that most ratepayers were upset about TOU pricing, which they believed resulted in higher electricity bills than previously. Our work at Hydro One also noted complaints from ratepayers about estimated bills or no bills for extended periods due to Hydro One's billing-system problems and connectivity issues between smart meters and associated communication systems; and about bills based on errors arising from smart meters connected to incorrect addresses.

Duplication of Services by Provincial Data Centre and Local Distribution Companies' In-house Systems

Under Smart Metering, the IESO is recovering the cost of its $249-million provincial data centre, called the Meter Data Management and Repository (provincial data centre), from all residential and small-business ratepayers through a Smart Metering Charge of 79¢ per month that began in May 2013 and was set to end in October 2018. These costs were not included in the initial cost projection of $1 billion made by the OEB for implementing Smart Metering.

Of the 4.8 million smart meters installed across the province, approximately 812,000 have not transmitted any data to the provincial data centre for processing. Although these ratepayers have never benefited from the provincial data centre, they still have to pay the monthly Smart Metering Charge of 79¢, totalling about $42.1 million up to October 2018.

The IESO has exclusive authority to develop and operate a provincial data centre in which to process smart-meter data for the province. However, the goal of operating the provincial data centre as a central system to ensure standard and cost-effective data processing has not been met because most distribution companies have used their own systems to process smart-meter data (before transmitting it to, or after receiving it from, the provincial data centre) for billing purposes. The provincial data centre was not available when some distribution companies started to roll out smart meters. Of the distribution companies we consulted, 88% indicated that the provincial data centre and their own systems have similar functions, resulting in redundancy. The costs of this duplication—one system at the provincial level and another locally—are passed on to ratepayers. The monthly operating cost for the local systems is, on average, about 21¢ per meter, which is being borne by ratepayers on top of the 79¢-a-month Smart Metering Charge.

Limitations of Provincial Data Centre and Distribution Companies in Processing Smart-Meter Data

Several limitations in processing smart-meter data by the provincial data centre and the business processes at the distribution companies have affected the quality and usefulness of smart-meter data, which in turn can affect billings to ratepayers. These limitations were associated with situations such as meter replacements and power blackouts. Also, half the distribution companies we consulted indicated that the provincial data centre has limited capabilities for data retrieval and querying. In

August 2013, the IESO reported to its board that the provincial data centre was able to manage data queries during its early stage of implementation, but it was not designed to support the expected increases in volume of data-retrieval requests from distribution companies.

Contract Terms for Operating Fee of Provincial Data Centre Not Clear

The IESO and a private-sector vendor signed a five-year contract in 2006, with an option to extend for another two years, for developing, implementing and operating the provincial data centre. The IESO paid the vendor $81.7 million for services up to March 2013. However, the $13.4-million-a-year contract fee for the two-year extension period was almost double the $6.8-million-a-year cost of the previous five years. The IESO attributed a portion of the fee increase to the additional costs associated with changes made to the provincial data centre and the higher number of meters being put in service during the two-year extension period. We found that the fee increase was due mainly to an error stemming from a contract amendment that did not clarify the fee for the two-year extension period. The IESO noted that this was an oversight on the part of the vendor, the IESO and their counsels, and that since the vendor incurred losses on the contract, the error offered the vendor an opportunity to improve its commercial position.

Monitoring of Smart Metering-related Fire Safety Risk Not Sufficient

There have been cases of fires arising from smart meters in Ontario and in other jurisdictions. However, no accurate and complete information on smart meter-related fires was available in Ontario to determine and monitor the scope and extent of the problem across the province. Only anecdotal evidence was available, which indicated three possible root causes for the fires: improper installation of smart meters, defective smart meters and problems with old meter bases where smart meters are mounted.

OVERALL MINISTRY RESPONSE

Electricity systems around the world are adapting to meet the new and complex demands of technology advances and customer expectations. In 2004, the province took a critical step towards modernizing Ontario's electricity grid with the announcement of the Smart Metering Initiative.

The Ministry acknowledges that given the ambitious timeline to install smart meters by 2010 and the inherent structure of the distribution industry, with over 70 local distribution companies, that the initiative was both complex and challenging.

Faced with these challenges, the Ministry, the IESO, the OEB and local distribution companies worked collaboratively to make Ontario one of the first jurisdictions in North America to roll out smart meters.

The deployment of 4.8 million smart meters has brought a number of benefits to the province, including the ability of consumers to respond to price signals. Going forward, smart meters, as the base technology for a modern grid that enables emerging technologies and applications like electric vehicles, electricity storage and innovations to make Ontario homes smarter, will continue to deliver value to Ontario.

The Ministry will incorporate the recommendations of the Auditor General's report when working in partnership with our agencies and the broader sector to deliver future smart meter initiatives and related investments.

Detailed Audit Observations

Governance and Oversight of Planning and Implementation

In April 2004, the Ontario government announced the Smart Metering Initiative (Smart Metering)—the first and the largest smart-meter deployment in

Canada—and set aggressive targets to install smart meters at the premises of all residential and small-business ratepayers by 2010, with an interim target of 800,000 installations by 2007. Given the size and complexity of Smart Metering, the Ministry of Energy (Ministry) had, and continues to have, an ongoing and ultimate responsibility as a central planner to ensure that effective governance and project management are in place to monitor planning and implementation.

Insufficient Justification and Planning for Smart Metering

A key principle of effective governance and project management is the use of comprehensive and relevant information about costs, benefits and risks to assess whether a proposed project is cost-effective and viable on an ongoing basis. This helps ensure that money is invested only if there is a continuing net benefit. Typically, cost-benefit analyses and business cases are two ways to evaluate the cost-effectiveness of a project, ensure that prudent decisions are made, and determine how stakeholders, and in this case electricity ratepayers, could be affected. As noted in the following sections, we found that the justification and planning for Smart Metering were insufficient.

Cost-benefit Analysis Not Done Before Public Announcement of Smart Metering

All key parties involved in implementing Smart Metering, including the Ministry, the Ontario Energy Board (OEB) and the Independent Electricity System Operator (IESO), confirmed to us that no cost-benefit analyses or business-case studies were done before the government announced Smart Metering in April 2004. Specifically, the OEB said it did not undertake any cost-benefit study because the Minister directed it only to develop an implementation plan (see **Figure 2**). The OEB plan noted, however, that many stakeholders and ratepayers expressed concern about the lack of a cost-benefit analysis and felt that, in particular, smart meters would not be justified for ratepayers using low volumes of electricity. In addition, senior IESO management asked the Ministry several times for a business case to support Smart Metering, but never got one.

From our research, we noted that other jurisdictions have initially and continuously assessed the cost-effectiveness and feasibility of their smart-metering programs. For example:

- British Columbia began a smart metering program in 2011 after BC Hydro developed a business case in 2006, which it updated in 2010 because of the continued evolution of the smart-metering industry and technologies. The business case summarized the cash flows for costs and benefits over a 20-year term, and estimated the annual impact on electricity bills. In response to ratepayers who did not want smart meters, BC Hydro announced in July 2013 that anyone could opt out of the smart-metering program by paying a monthly fee to cover the cost of manual meter readings.
- The government in Victoria, Australia, commissioned two cost-benefit studies in 2004 and 2005 that became the basis for its 2006 decision to mandate the rollout of smart meters to all homes and small businesses. However, the Australian Government Productivity Commission concluded in 2012 that inadequate cost-benefit analysis had been done and that, overall, the decision to roll out smart meters appeared to be premature and/or poorly planned, with inadequate knowledge about smart-meter technologies, their costs and associated risks.
- In Germany, the government published a study in July 2013 that analyzed the costs and benefits of a full rollout of smart meters. The study concluded that smart meters were not cost-efficient for small ratepayers because they would cost more to buy, install and operate for average households than the

potential savings they would generate. The German government concluded it was not in the interest of ratepayers to implement a 2009 European Union recommendation that member states provide smart meters to 80% of ratepayers by 2020, and suggested instead a rollout tailored to different ratepayer groups, based on how much electricity they consume.

- The British government began preparatory work on its smart-metering program in 2009 and a business case was approved two years later. The government conducted further assessments in January 2014 to update the initial cost and benefit estimates, and it developed an overall strategy in mid-2014 to install smart meters in all homes and small businesses by 2020.

Compared to the experience in these other jurisdictions, the implementation of Smart Metering in Ontario without proper cost-benefit analysis to support the initial decision to install smart meters significantly exposed the province to unanticipated risks and unknown costs.

OEB's Role as Independent Regulator Set Aside

Shortly after the government announced Smart Metering in April 2004, the Minister of Energy (Minister) issued a directive to the OEB under the *Ontario Energy Board Act, 1998* (Act), requiring it to develop an implementation plan to achieve the government's smart-meter targets. Under the Act, the Minister has the authority to direct the OEB to promote electricity conservation in a manner consistent with government policy. The Ministry also contracted with an external consultant in January 2005 to analyze different implementation strategies and to estimate the benefits of Smart Metering.

Both the Act and the directive essentially provided the Minister with the authority to set aside the regulatory role of the OEB (an independent Crown corporation responsible for regulating Ontario's electricity and natural-gas sectors in the public interest) in Smart Metering. The OEB's mandate includes protecting the interests of ratepayers with respect to electricity prices. However, instead of conducting a cost-benefit analysis to justify its decision, and submitting the analysis to the OEB for independent review and objective evaluation, the Ministry, as a proponent of Smart Metering, directed the OEB to develop the implementation plan and project the costs of Smart Metering, as noted in the following section.

Cost-benefit Analysis, Prepared After Public Announcement of Smart Metering, Flawed

In the implementation plan it submitted to the Ministry in January 2005, the OEB projected the total cost of implementing Smart Metering at $1 billion, plus a net increase of $50 million a year to the operating costs of the province's distribution companies. A separate consultant's report, delivered to the Ministry three months after the OEB submitted its implementation plan, projected total benefits of Smart Metering would be approximately $1.6 billion over 15 years from four sources as shown in **Figure 4**, which indicated that about half of the projected benefits would result from a reduction in distribution companies' operating costs and a reduction in ratepayers' energy costs, and half

Figure 4: Summary of Projected Net Benefits of Smart Metering Initiative ($ billion)
Source of data: Ministry of Energy

Reduction in distribution companies' operating costs	0.4
Reduction in ratepayers' energy costs	0.4
Avoidance of expanding power generating capacity	0.6
Deferral or avoidance of expanding transmission and distribution systems	0.2
Total Projected Benefits[1]	**1.6**
Total Projected Implementation Cost[2]	**(1.0)**
Projected Net Benefits	**0.6**

1. Benefits projected by an external consultant engaged by the Ministry.
2. Cost projected by the OEB.

from deferring or avoiding the expansion of power generating capacity as well as transmission and distribution systems.

After considering the OEB's implementation plan and the separate consultant's report, as well as consulting the distribution companies, the Ministry requested Cabinet approval to proceed with smart metering based on a dual-implementation approach: decentralized ownership of smart meters by the distribution companies, and centralized data management by a provincial agency (see **Figure 2** and the section **Smart-meter Data Processing Systems and Costs**). In its October 2005 request to Cabinet, the Ministry indicated to Cabinet that Smart Metering could yield net benefits of close to $600 million over 15 years. As shown in **Figure 4**, the Ministry arrived at this number simply by subtracting the projected implementation cost of $1 billion in the OEB plan from the projected benefits of $1.6 billion over 15 years in the consultant's report. However, we found that the $600 million in net benefits was overstated, because it did not include the OEB plan's projected net increase of $50 million a year to distribution companies in operating costs. By taking the $50-million-a-year figure into account, we calculated that the projected net benefits over 15 years would be reduced seven-fold, from $600 million to $88 million in today's dollars.

Ineffective Implementation and Oversight of Smart Metering

Given the large scale of Smart Metering and the high risk associated with new technology, its implementation should have warranted strong governance and oversight. However, we identified the following issues regarding the targets of reducing peak electricity demand, the assessment of changes in the electricity market, and the monitoring of costs and benefits of Smart Metering.

Peak-demand Reduction Targets Not Met

The key objective of Smart Metering was to reduce peak electricity demand, and therefore defer the need to expand power-generation capacity in Ontario. In the decade since Smart Metering was announced, the province approved significant increases in new generation, including renewable energy, and the supply of power actually rose 12%. During this same period, average electricity demand also dropped 8% due to a slowing economy and other conservation efforts, including, for example, newer energy-efficient appliances. Despite the reduction of average demand, peak demand has remained essentially unchanged over the same period.

The Ministry indicated that Smart Metering was only a component of the government's overall electricity conservation plan, and so there was no other specific target for Smart Metering. Instead, the Ministry set several peak-demand reduction targets to measure overall electricity conservation, including a 1,350MW reduction by 2007, an additional 1,350MW drop by 2010, and a further 3,600MW reduction by 2025. We found that:

- The initial 1,350MW targeted reduction in peak demand was irrelevant to Smart Metering anyway because it was supposed to be achieved by 2007, three years before full installation of smart meters was to be completed.
- The second target of reducing peak demand by an additional 1,350MW by 2010, for a total reduction of 2,700MW, was also irrelevant to Smart Metering, which had not been fully implemented by 2010. While approximately 4.6 million ratepayers had smart meters installed by the end of 2010, only about one-third (or 1.6 million) of them were being billed based on time-of-use (TOU) pricing. Actual peak demand in fact rose slightly by about 100MW, from 24,979MW in 2004 to 25,075MW in 2010. In measuring against the target, the Ministry indicated that as of December 31, 2010, peak demand was

reduced by about 1,800MW when measured against forecast and weather-adjusted peak demand data rather than actual demand data, but the 2010 reduction target of 2,700MW still was not met. Since 2010, actual peak demand has remained relatively stable.

Ongoing Changes in Electricity Market Not Properly Assessed or Addressed

The pace of change in the electricity sector has been rapid, so proper and adequate planning, with ongoing assessment and monitoring of plans, is important to prepare for potential risks and costs in implementation of any new electricity initiative. However, we noted that Smart Metering was implemented without sufficient periodic re-evaluation of Ontario's electricity supply and demand positions throughout the implementation period.

During the early implementation stage of Smart Metering in 2006, demand for electricity fell in Ontario as a result of an economic recession and other conservation efforts. However, instead of adjusting to this fall in demand, the province approved significant new increases in power-generation capacity to replace coal, and maintained the aggressive timelines set for implementation of Smart Metering. As a result, the supply of available power has steadily increased, and has been consistently higher than peak demand, thereby reducing the effectiveness of Smart Metering and other conservation programs. Although the IESO is required to maintain an operating reserve of between 1,300MW and 1,600MW for contingencies and other uncertainties, we noted that since 2009, the available surplus power of between 4,000MW and 5,900MW was considerably more than the required reserve. The IESO expected that the surpluses will continue in 2015, but could decline in the latter half of this decade when several nuclear plants will be refurbished or retired.

Ontario has been exporting most of its surplus power to the United States through the transmission grid connecting it to neighbouring jurisdictions, including New York, Michigan and Minnesota. We noted that net exports have grown by 158%, from 5.2TWh in 2006 to 13.4TWh in 2013, representing 3% and 9% of Ontario's total generation, respectively.

However, the export price has been well below the actual cost of generating this power. On average, other jurisdictions paid only about three to four cents per kWh for power that cost Ontario ratepayers more than 8¢ per kWh to produce because of the Global Adjustment, an extra charge on top of the electricity market price (see the section **Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers**). The total cost of producing the exported power was about $2.6 billion more than the revenue Ontario received from exporting that power between 2006 and 2013. However, given that Ontario ratepayers would still have to pay for the production of surplus power even if that power was not exported, revenue from exports did help Ontario ratepayers pay for part of the Global Adjustment.

Costs and Benefits Not Monitored

The Ministry has neither updated the projected costs and benefits prepared in early 2005 during evolution of the implementation process, nor tracked the actual costs and benefits in order to monitor the amount of net benefits realized. We conducted our own analysis to determine the actual costs and benefits to date, and found as follows:

- With respect to costs, the OEB confirmed that there was no process to check or update its projected implementation cost of $1 billion and compare it against actual costs because the Minister never formally approved the OEB's implementation plan. We calculated that, based on our review of information submitted by the distribution companies to the OEB, the total cost incurred by the distribution companies to implement Smart Metering was about $1.4 billion up to the end of 2013, or $400 million more than the cost projection in the OEB plan. The final total will be higher still because some distribution companies were still carrying out implementation at the time of our audit and had not yet submitted all of their costs to the OEB for review. The OEB also indicated that the Ministry, the IESO and the distribution companies incurred additional costs for activities brought in after the OEB's implementation plan was prepared, including the development, implementation and operation of a provincial data centre at a cost of about $249 million (see the section **Ratepayers Charged for Redundant or Unused Provincial Data Centre Service**). As shown in **Figure 5**, we noted that as of May 2014, the total approximate costs of implementing Smart Metering had reached almost $2 billion.

- With respect to benefits, only 5% of the distribution companies we consulted reported operational savings, mainly from no longer having to send staff to read meters manually, and all of these were of modest size; the other 95% said they realized no savings and their operating costs relating to smart-metering activities since implementation had actually risen. As well, the savings achieved by ratepayers were so far limited, contrary to government communications to the public that smart meters and TOU pricing would help "save money" and "lower electricity bills" if appliances were run during Off-Peak hours. In fact, over half of the distribution companies we consulted received a high volume of complaints about "increased bills with no savings" from ratepayers with smart meters who paid TOU rates (see **Appendix 1**). In addition, several large distribution companies analyzed a sample of their residential ratepayers and found that a majority would see no reduction in their bills after implementation of TOU pricing. Therefore, of the four sources of projected benefits shown in **Figure 4**, two of them (reduction of distribution companies' operating costs and reduction in ratepayers' energy costs) have not been achieved. The remaining two sources of benefits (avoiding expansion of power-generation capacity and deferring or avoiding expansion of transmission and distribution systems) have yet to be seen because, as noted previously, the 2010 peak-demand reduction target was not met and actual peak demand has remained relatively stable since 2010.

RECOMMENDATION 1

To ensure that any future major initiative in the electricity sector is implemented cost-effectively and achieves its intended purposes, the Ministry of Energy should:

- conduct cost-benefit analysis or business cases prior to implementing an initiative to assess costs, benefits and risks;
- review the role of the Ontario Energy Board as an independent regulator when ministerial directives that impact electricity rates are issued;
- consider different scenarios or alternatives as part of the planning process to assess possible risks and uncertainties; and
- re-evaluate and update the implementation plan periodically to identify and respond to changing conditions and unforeseen events in the electricity market.

MINISTRY RESPONSE

In line with best practice, the Ministry will ensure that the proper analysis is completed ahead of implementing major initiatives. In addition, the Ministry will continue to work with the relevant sector participants in a partnership approach to ensure that cross-sector initiatives are appropriately planned and consider the respective roles of those involved.

Also in line with best practice, the Ministry respects the need to evaluate programs on a regular basis to maximize efficiencies. To this end, the Ministry will work with its agencies to re-evaluate the implementation of smart meters, including the potential benefits they could enable through the development of a smart grid in Ontario.

Figure 5: Summary of Costs Incurred by Entities Involved in the Smart Metering Initiative, 2005–2014

Prepared by the Office of the Auditor General of Ontario

Entity	Date	Cost Description	Approx. Cost ($ 000)	Report Section (if applicable)
Ministry of Energy	Jan. 2005–Apr. 2005	Engaging an external consultant to develop an implementation strategy and to estimate the benefits of Smart Metering	160[1]	Ineffective Implementation and Oversight of Smart Metering Initiative
	Nov. 2005–Apr. 2006	Engaging experts for technical, system and legal supports during early implementation stage of Smart Metering	400[1]	
	2006–2010	Developing Communication templates and materials for use by the distribution companies to raise public awareness and understanding of Smart Metering	640[1]	
Ontario Energy Board (OEB)	Jul. 2004–Jan. 2005	Developing the implementation plan for Smart Metering Initiative requested by the Minister	420	Ineffective Implementation and Oversight of Smart Metering Initiative
	Nov. 2010–May 2014	Engaging an external consultant to set time-of-use (TOU) rates	410	Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers
	Mar. 2013–Mar. 2014	Engaging an external consultant to assess the impact of TOU rates on consumption patterns	180	Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers
Independent Electricity System Operator (IESO)	2006–2014	Developing, implementing and operating a Smart Metering Entity and a provincial data centre	160,000[1,2]	Ratepayers Charged for Redundant or Unused Service
Local Distribution Companies	2006–2013	Implementing Smart Metering	1,400,000[3]	Ineffective Implementation and Oversight of Smart Metering Initiative
	2005–2014	Scrapping conventional analog meters	400,000[4]	Additional Costs of Implementing Smart Metering Initiative
Total			**1,962,210[5]**	

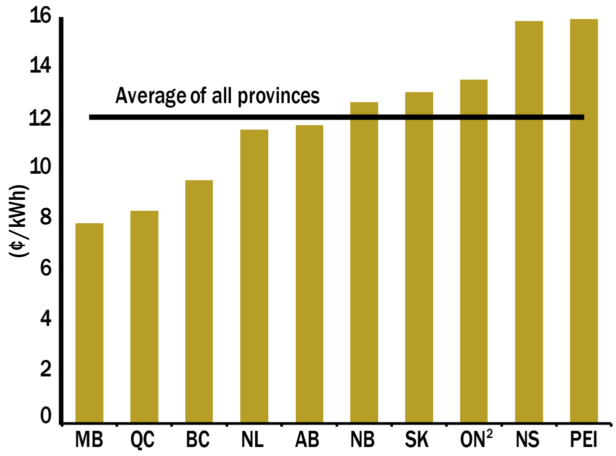
1. Covers activities added after OEB's 2005 implementation plan, or those outside the original scope of the Smart Metering Initiative.
2. Total approved by the OEB was $249 million up to 2017. This cost is being recovered from ratepayers through a monthly smart-metering charge of 79 cents. The amount up to 2014 was approximately $160 million.
3. Hydro One accounted for more than $660 million of the $1.4 billion spent by all 73 distribution companies. About $500 million (mainly from Hydro One) of the $1.4 billion is under review by the OEB and has yet to be approved by the OEB.
4. We reviewed the OEB's 2005 estimate. In our view, this is a reasonable estimate of total stranded costs.
5. See Figure 15 for other system-related costs incurred by the distribution companies that we interviewed and surveyed.

Billing Impacts on Electricity Charge to Ratepayers

Our research noted that the average electricity bill for residential and small-business ratepayers in Ontario has been among the highest in Canada, as shown in **Figure 6**. Ontario's typical electricity bill for residential and small-business ratepayers contains four categories of charges: Electricity, Delivery, Regulatory and Debt Retirement. Smart Metering has had an impact on the two biggest categories, Electricity and Delivery, as described in **Figure 7**. There are three key pricing methods for the Electricity Charge, as illustrated in **Figure 8**. Over 90% of residential and small-business ratepayers pay this charge based on time-of-use (TOU) pricing, which is enabled by smart meters to measure the exact time when electricity is used. The remaining 10% pay either a two-tiered rate, often because they live in places where it is not technically feasible or cost-effective to install smart meters, or fixed-contract prices to electricity retailers, who do not offer TOU rates.

Figure 6: Comparison of Average Electricity Bill (Excluding Taxes) for Residential and Small-business Ratepayers[1] by Province, as of April 1, 2014

Source of data: Hydro Quebec



1. Residential electricity bill was based on average ratepayer with consumption of 750 kWh/month. Small-business electricity bill was based on average ratepayer with power demand of 40 kW/month.
2. Ontario figure includes Ontario Clean Energy Benefit, which is a 10% rebate on the total electricity bill, as illustrated in Figure 7.

Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers

The Electricity Charge accounts for more than half of a typical residential electricity bill, as shown in **Figure 7**, and is made up of two components: the electricity market price and the Global Adjustment. The Global Adjustment is an extra charge, resulting from a government policy decision, that is tacked onto the electricity market price mainly to cover the gap between the guaranteed prices paid to contracted power generators and the electricity market price. It exists because most power generators in Ontario have contracts with the province that pay them more than the market price. For example, most renewable-energy generators such as wind and solar have contracted with the Ontario Power Authority under the Feed-in Tariff program that offers wind-power generators 11.5¢/kWh and solar power generators between 28.8¢/kWh and 39.6¢/kWh. These contract prices are considerably higher than the average electricity market price of about 3¢/kWh.

Our review of trends in the Electricity Charge noted that the Global Adjustment has continued to increase to the point where it now significantly exceeds the electricity market price. This is the result of many new generators, especially in the renewable-energy sector, coming online with long-term contracts just as the market price has fallen due to oversupply of power and thus been insufficient to cover guaranteed contract prices. As shown in **Figure 9**, the Global Adjustment increased by a dramatic 1,200% between 2006 and 2013, from 1.4¢/kWh to 5.5¢/kWh, and is expected to grow to 6.7¢/kWh by 2015. During the same period, the average electricity market price has dropped by 46%, from 4.9¢/kWh to 2.7¢/kWh, and is expected to fall to 2.4¢/kWh by 2015 due to increasing electricity supply.

The total Global Adjustment charged to ratepayers has grown from $654 million in 2006 to $7.7 billion in 2013, as shown in **Figure 10**. With more new contracted generators, especially of renewable energy, expected to begin producing energy at higher contract prices, the total Global Adjustment is expected to grow further, to $8.5 billion in 2014 and $9.4 billion in 2015. From 2006 to 2015, the 10-year cumulative actual and projected Global Adjustment is about $50 billion—an extra charge to ratepayers over and above the market price of electricity. To put this into perspective, $50 billion is:

- sufficient to cover the 2014 provincial deficit of $10.5 billion almost five times;

Figure 7: Components of Electricity Bill with Examples, 2013
(Average Typical Residential Ratepayer Consuming 800 kWh/Month)
Source of data: Ontario Energy Board (OEB)

Bill Component	Description	Distribution Company A ($)	Distribution Company B ($)	Avg. of all Distribution Companies ($)
Electricity Charge	The cost of the actual electricity consumed. Presentation of this charge on bills varies, depending on whether the ratepayer buys electricity from a distribution company or has signed a contract with a retailer. Over 90% of low-volume power use ratepayers (residential and small businesses) pay power charges based on time-of-use pricing, enabled by installation of smart meters (see Figure 6).	71.1	71.1	71.1
Delivery Charge*	The cost of delivering electricity from power-generating facilities to ratepayers via high-voltage (transmission) and low-voltage (distribution) systems. Transmission is handled primarily by Hydro One and distribution is handled by the distribution companies, including Hydro One. Costs of implementing and operating smart meters are included in this line and vary from one distribution company to another, usually with higher charges in rural and remote locations.	24.9	110.6	43.6
Regulatory Charge	The cost to operate the electricity market and maintain the reliability of the provincial grid. This includes the operational costs of the IESO and the Ontario Power Authority as well as a portion of administrative costs of local distribution companies.	4.9	5.1	5.0
Debt Retirement Charge	Charge mandated by the government to help pay off the residual stranded debt of the old Ontario Hydro that could not be funded by other revenues. The 2014 Budget proposed to eliminate this charge for residential ratepayers after December 31, 2015.	5.6	5.6	5.3
Electricity bill before tax and benefit		**106.5**	**192.4**	**125.0**
Harmonized Sales Tax	The 13% tax that took effect on July 1, 2010, replacing the federal goods and services tax (GST) and the provincial sales tax (PST).	13.9	25.0	16.3
Ontario Clean Energy Benefit	A 10% rebate on the total electricity bill for the first 3,000 kWh/month of electricity consumed. Rebate is in effect from 2011 to 2015. Annual cost of rebate is funded by taxpayers.	(12.0)	(21.8)	(14.1)
Total Electricity Bill		**108.4**	**195.6**	**127.2**

* See Appendix 2 for the Delivery Charge of each distribution company in Ontario.

- enough to pay the annual salary of about 2.3 million Ontarians working full time at the provincial minimum wage; or
- about 7.5 times more than the $6.6-billion spent in the 2012/13 fiscal year on social-assistance programs such as the Ontario Disability Support and Ontario Works programs administered by the Ministry of Community and Social Services.

For ratepayers whose Electricity Charge is based on TOU pricing, the Global Adjustment now accounts for about 70% of each TOU rate. Even though the Global Adjustment has increased significantly and accounts for a substantial proportion of

Figure 8: Pricing Methods for Electricity Charge

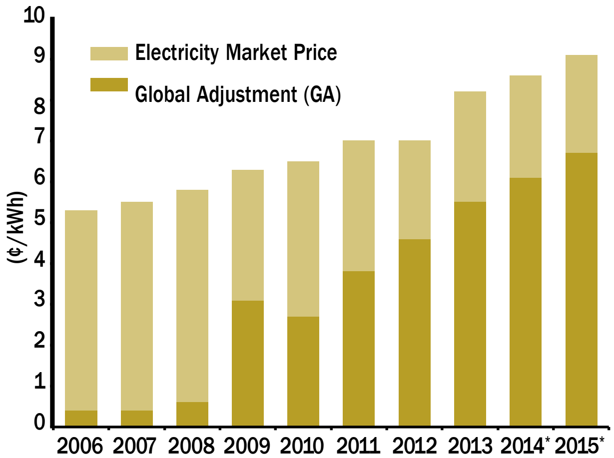
Source of data: Ontario Energy Board (OEB)

Pricing Method	Time-of-Use (TOU)	T	iered	Retail Contrac
Electricity Provider	Local Distribution Company	Local Distribution Company	Electricity Retailer	
Electricity Charge based on Time-of-Use?	YES Rates vary depending when electricity is used, reflecting that electricity costs more as demand rises (highest during the day on weekdays and lowest in evenings, at night, on weekends and holidays).	NO Rates are fixed in two tiers regardless of when electricity is used (a lower rate for monthly usage up to a threshold and a higher rate for usage over the threshold).	NO Rates are fixed by contracts that ratepayers sign with retailers no matter what time of day electricity is used.	
Electricity Charge Regulated by Ontario Energy Board (OEB)?	YES OEB reviews and sets TOU and tiered rates twice a year (May 1 and Nov 1) based on future electricity prices estimated by an external consultant.		NO	
Global Adjustment* Shown Separately on Bill?	NO Global Adjustment is blended into TOU and tiered rates, and embedded in the Electricity Charge line on electricity bill.		YES Global Adjustment appears as a separate line on electricity bill.	

* The Global Adjustment is an extra charge designed to cover the contract prices paid to power generators, such as renewable energy generators, and the cost of conservation programs.

Figure 9: Historical and Projected Electricity Charge in Ontario, 2006–2015

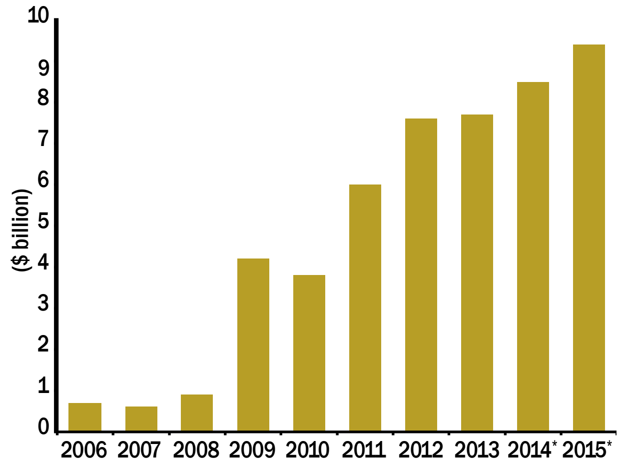
Source of data: Independent Electricity System Operator and Ontario Power Authority



* projected

Figure 10: Historical and Projected Total Annual Global Adjustment Charged to Electricity Ratepayers in Ontario, 2006–2015

Sources of data: Independent Electricity System Operator and Ontario Power Authority



* projected

Chapter 3 • VFM Section 3.11

the TOU rates, its impact is not transparent to most ratepayers because it does not appear on electricity bills as a separate line; instead, it is embedded in the TOU rates used to calculate the Electricity Charge (As shown in **Figure 8**, the Global Adjustment only appears separately on bills of those ratepayers who have signed contracts with electricity retailers).

Ineffective Design of Time-of-use Rates and Periods

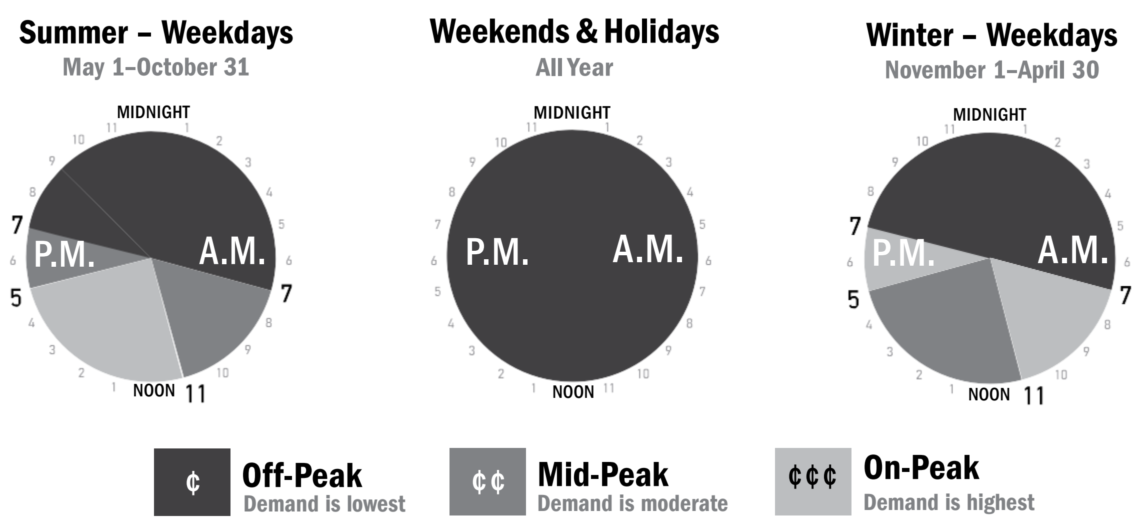
As part of Smart Metering, there are three time-of-use (TOU) rates: On-Peak, Mid-Peak and Off-Peak, consistent with the TOU design in other jurisdictions. As illustrated in **Figure 11**, TOU rates vary, depending on the time of the day, day of the week, and season, to reflect the assumption that as demand rises, electricity costs more to supply. Like many cell phone plans, TOU rates are lowest in the evenings, on weekends and holidays; and highest during the day on weekdays. The combination of smart meters and TOU pricing was expected to encourage energy conservation by giving ratepayers information and incentives to manage their electricity usage.

To account for seasonal variations in electricity consumption patterns, the OEB reviews and sets TOU rates every May and November, based on consumption and cost projections made by an external consultant with whom it contracted. Ontario Regulation 95/05 requires that the OEB set the TOU rates to meet three objectives:

- recover from ratepayers the full cost of electricity supply;
- reflect the differences in the costs of supplying electricity at different times and seasons; and
- provide ratepayers with incentives to change their time of use.

In order to encourage conservation and reduce peak electricity demand, TOU rates and periods

Figure 11: Time-of-use Pricing Periods in Ontario for Residential and Small-business Ratepayers
Source of data: Ontario Energy Board (OEB)



Summer Weekdays (May 1–October 31)	Weekends & Holidays (All Year)	Winter Weekdays (November 1–April 30)
One On-Peak period in the afternoon (11 a.m.–5 p.m.), mainly due to the increase in air conditioner use during the hottest hours.	No On-Peak period and all hours Off-Peak, mainly because of comparatively lower overall demand.	Two On-Peak periods, mainly due to less daylight. • In the morning (7 a.m.–11 a.m.) when people turn on lights and appliances. • In the evening (5 p.m.–7 p.m.) when people get home from work.

must be set to provide an incentive to reduce usage during On-Peak times, when both demand and price are high, or shift it to Off-Peak times, when both demand and price are low.

With respect to the TOU rates, the greater the difference between On-Peak and Off-Peak rates, the higher the likelihood that ratepayers will change their usage patterns. However, we noted that the difference between On-Peak and Off-Peak rates in Ontario may not be significant enough to provide ratepayers with an incentive to change their electricity-use behaviour. Specifically:

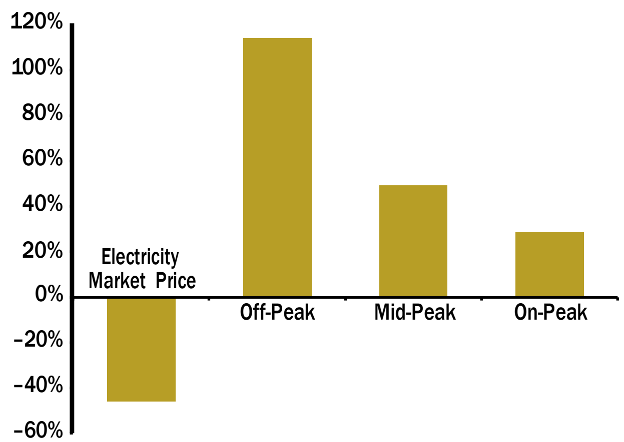
- When TOU pricing was introduced in 2006, the initial On-Peak–to–Off-Peak ratio was three-to-one, meaning that On-Peak power cost three times as much as Off-Peak. However, the ratio had dropped to 1.8-to-one at the time of our audit due to the impact of the substantial growth of the Global Adjustment, as discussed in the section **Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers**. In particular, the Off-Peak rate rose the most, by 114%, and the On-Peak rate the least, by 29%, as shown in **Figure 12**. As a result, the difference between the two rates narrowed, reducing the On-Peak–to–Off-Peak ratio and undermining TOU pricing as an incentive for ratepayers to shift to Off-Peak.
- In 2010, the OEB commissioned an external consultant to study TOU rates around the world and assess the appropriateness of Ontario's TOU rates. Consistent with our observation above, the consultant reported that Ontario's On-Peak–to–Off-Peak ratio was "low relative to TOU programs in other jurisdictions and will likely produce modest ratepayer response or bill savings." The average ratio elsewhere was four-to-one, compared to Ontario's 1.8-to-one. The Ontario ratio could deliver only about a 1% drop in the average ratepayer's peak demand, while a four-to-one ratio could potentially yield a drop three times greater. The study proposed several options to increase the ratio. However, following a consultation in 2011, the OEB chose not to make any change because a majority of stakeholders said such a move would be premature in the absence of robust and reliable Ontario-based empirical data.

With respect to the TOU periods, we noted that the distribution of On-Peak, Mid-Peak and Off-Peak periods did not fully reflect actual patterns of electricity use. Specifically:

- There has been a mismatch between demand and TOU rates on weekday early-evening hours (7 p.m.–9 p.m.), when demand is high but ratepayers pay the Off-Peak, or lowest, rate. The OEB initially set the Off-Peak period on weekday evenings to begin at 10 p.m., and then moved it to 9 p.m. in November 2009 to better reflect actual patterns of demand. However, in response to amendments to Ontario Regulation 95/05 in December 2010, the OEB set the start of Off-Peak at 7 p.m., making the early evening hours of 7 p.m. to 9 p.m. Off-Peak, even though demand remained high at those times, as illustrated in **Figure 13**.
- A 2013 study by an Ontario university found that the choices of On-Peak and Off-Peak times, number of seasons, and season start

Figure 12: Percentage Change of Time-of-use (TOU) Rates and Electricity Market Price in Ontario, 2006–2014

Source of data: Ontario Energy Board and Independent Electricity System Operator



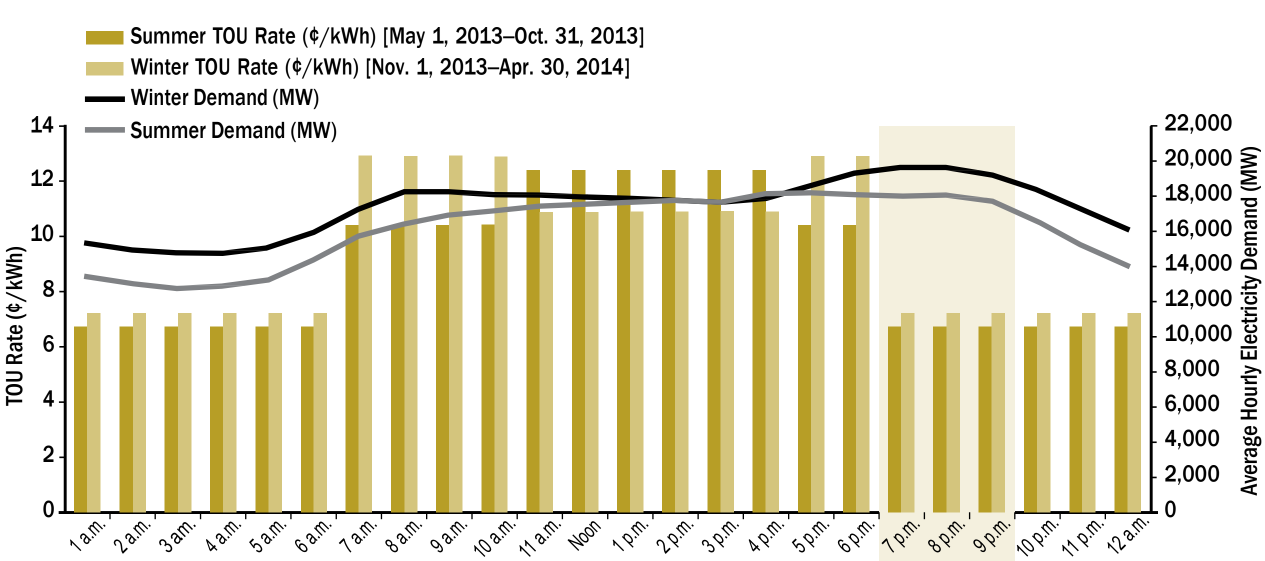
and end times used in Ontario's TOU pricing were far from optimal. The study echoed our observation that the distribution of On-Peak, Mid-Peak and Off-Peak periods did not properly reflect the actual distribution of demand. The study also found that while the current TOU pricing structure has two seasons (summer: May 1-October 31, and winter: November 1-April 30), the optimal number of seasons should be four, beginning March 11 (spring), May 20 (summer), September 16 (fall) and November 4 (winter). If the current two-season pricing structure is to be maintained, the study said, summer should start on April 15 rather than May 1, and winter on October 14 rather than November 1.

Limited Effectiveness of Time-of-use Pricing Model

At the time of our audit, the distribution companies we consulted said they did not conduct studies to examine the changes in consumption after implementation of TOU pricing. The impacts of TOU pricing were evaluated in 2013, when the Ontario Power Authority (OPA) and the OEB contracted with external consultants to examine the effectiveness on a sampling of ratepayers of TOU pricing in encouraging conservation and reducing peak demand. Both agencies released their studies in late 2013 with similar findings: TOU pricing has had a modest impact on reducing peak demand among residential ratepayers, a limited or unclear effect on small businesses, and no impact at all on energy conservation. Specifically:

- In November 2013, the OPA released its study, based on 105,000 residential ratepayers in four distribution companies, and 32,000 small businesses in two distribution companies. The study found that TOU pricing had a far smaller impact on reducing peak demand of small businesses than it did for residential ratepayers. Depending on the distribution company, the drop in peak demand during the summer ranged from 2.6% to 5.7% for residential ratepayers, but only from 0% to 0.6% for small businesses. The study also found that the impact of TOU pricing on energy conservation was "limited, being very small or zero," for residential ratepayers, and "negligible and generally insignificant" for small businesses.
- In December 2013, the OEB released its study, based on a sample of 10,000 residential ratepayers and 4,000 small businesses in

Figure 13: Time-of-use (TOU) Rates and Average Hourly Electricity Demand in Ontario, May 2013–April 2014
Sources of data: Independent Electricity System Operator and Ontario Energy Board



16 distribution companies. The study found that TOU pricing reduced peak demand by about 3.3% for residential ratepayers while its impact on small businesses was "ambiguous." The study also found that TOU pricing had no significant impact on energy conservation in the summer.

We performed further analyses based on more current data and larger sample sizes. Specifically, we reviewed consumption patterns of about 1.8 million ratepayers (1.7 million residential ratepayers and 86,000 small businesses in 50 of 73 distribution companies), who paid TOU rates. While 35% of residential ratepayers and 19% of small businesses reduced their consumption during On-Peak periods, the remaining 65% of residential and 81% of small businesses did not.

Since the aforementioned studies by the OPA and the OEB did not specifically cover ratepayers with smart meters who signed fixed-price contracts with energy retailers and so do not pay TOU rates, we examined the consumption patterns and bills of about 77,000 of these ratepayers. Given that they paid fixed prices regardless of time of use, these ratepayers have little or no incentive to confine their consumption to Off-Peak periods, when TOU rates were lowest. However, we noted that consumption patterns of ratepayers paying fixed-contract prices to electricity retailers, and of ratepayers paying TOU rates, were about the same, indicating that TOU rates did not provide ratepayers with sufficient incentive to shift usage to Off-Peak. We also noted that those ratepayers with retail contracts paid an average of about $500 more per year for electricity than they would have without the contracts.

Ratepayer Complaints Stemmed from Time-of-use Pricing and Billing Errors

Ratepayers usually raised questions and concerns about Smart Metering by contacting the OEB and the distribution companies. Since 2008, the OEB has received about 2,400 enquires and complaints relating to smart meters and TOU pricing; about two-thirds of them questioned the TOU pricing structure and whether it would save them money. Given that ratepayers get their bills directly from the distribution companies, the companies received even more enquiries and complaints.

Many distribution companies we consulted did not track enquiries and complaints separately, nor did they log the nature or type of complaints. They were thus unable to quantify the volume of complaints relating to Smart Metering before and after its implementation, and could not separate concerns about smart meters from those about billing. Without proper tracking and monitoring of ratepayer concerns, key information could not be collated to identify and resolve common or recurring problems on a timely basis.

Those distribution companies that had tracked the nature of complaints reported that a majority of the concerns raised by ratepayers related to TOU pricing and fell into the following categories (see **Appendix 1**):

- Ratepayers were upset about high electricity bills or "increased bills with no savings," which they believed were caused by faulty smart meters, but were in fact due to the increase of TOU rates as a result of the significant growth of the Global Adjustment (see section **Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers**).
- Ratepayers had "limited understanding and information about TOU pricing;" and
- Ratepayers had "limited or no ability to change electricity consumption," especially small businesses and individuals at home during most of the day.

For Hydro One, Ontario's largest distribution company and the only one owned by the province, we performed additional detailed reviews of ratepayer enquiries and complaints. In February 2014, four months after we began our audit, the Ontario Ombudsman also began an investigation into complaints at Hydro One. In order to avoid duplication with that undertaking, we modified our audit scope to focus on identifying the root causes of billing issues potentially relating to smart meters and TOU pricing. Of the complaints we examined at Hydro One, most related to high electricity bills due mainly to TOU rates and not to defective smart meters, just like the other distribution companies noted above. In addition to the high-bill concerns relating to TOU rates, we also identified a number of complaints about billing anomalies that fell into the following categories:

- **Billing System Problems:** In May 2013, Hydro One transitioned to a new billing system. However, the transition was not smooth. At the time of our audit, Hydro One was adapting to and working on some technical issues with its new system, but more complex issues had yet to be fixed. We identified complaints about erroneous bills, prolonged estimated bills, delayed bills, multiple bills or no bills at all, that were due to problems with the billing system. For example:
  - In September 2013, a ratepayer received a bill for about $37 million as a result of an error made in calculating electricity consumption, but Hydro One's billing system did not catch this error. In January 2014, the company cancelled the bill and revised the amount owing to about $35,000.
  - In September 2013, a ratepayer with a smart meter received an estimated bill covering electricity usage for seven months. After that, the ratepayer received no bills for five months due to billing-system problems. In April 2014, Hydro One issued 12 bills, all on the same date and for a total of over $4,900. Of these 12 bills, seven were to correct the under-estimated bill issued in September 2013 and five were to "catch-up" on the no-bill period since October 2013.
  - A smart meter installed in March 2012 was found to be malfunctioning, and was replaced in October 2012. However, the ratepayer was not billed until April 2013 due to problems in the billing system. In April 2013, the ratepayer received a "catch-up" bill of about $4,000 for usage between March 2012 and April 2013.
- **Communication System Problems:** Ratepayers did not receive any bills, or received only estimated bills, for extended periods, because actual consumption data was not available due to connectivity issues between the smart meters and associated local communication systems. The problems could be caused by non-communicating smart meters or by seasonal variations in system performance. With respect to the latter, Hydro One's service territory includes rugged terrain and extensive foliage that could block meter signals from reaching the systems, depending on the season. Communication systems in one region may work well in the fall and winter when most trees are bare of leaves, for example, but it may not function properly in the spring when trees have new leaves.
  - In December 2013, a ratepayer complained about receiving estimated bills for seven months, ranging from $400 to $500 per month, which was about two to three times higher than the previous monthly bills. Hydro One found that the smart meter was working properly, but it could not capture actual meter readings because its communication system was not producing a signal. Hydro One then corrected the over-estimated bills and credited the ratepayer for about $1,300 against future bills.
  - In December 2013, another ratepayer complained about receiving high estimated bills for nine months. Hydro One found that the bills were based on estimates rather than actual meter readings because the smart meter was not communicating with the system. Hydro One then cancelled the over-estimated bills and issued a credit of about $2,700 to the ratepayer.

- **Mixed or Cross-Metering Issues:** Ratepayers were billed based on errors arising from smart meters connected to wrong addresses during installation. Hydro One indicated that these issues also existed prior to the installation of smart meters but occurred rarely. Most ratepayers did not notice these issues because the amount of the errors was usually not significant; in other cases, however, they were. For example:
  - In response to a January 2012 query from a ratepayer about a high bill, Hydro One found that four smart meters in the same building had been mistakenly wired into the wrong addresses, and that the ratepayer who complained had been overbilled by about $1,000.
  - In response to an enquiry from another ratepayer in April 2013, Hydro One found that a smart meter in an apartment was erroneously connected to another address, and that the ratepayer was overbilled by about $200 from November 2012 to March 2013, when the smart meter was incorrectly connected.
- **Seasonal High Bills:** Unlike other distribution companies, Hydro One has wider geographic coverage and more seasonal ratepayers who own residential properties, such as cottages in rural or remote areas, in addition to their primary residence. Even though seasonal ratepayers used their properties mainly on weekends and holidays, they still received high electricity bills. For example, in February 2014, a ratepayer complained of bills totalling $7,000 a year on a cottage that was only used six months a year. The ratepayer attributed the high bills to a faulty smart meter, but Hydro One found that the smart meter was functioning properly. We identified other similar complaints that were caused by one or all of the following reasons:
  - The Electricity Charge on seasonal ratepayer bills rose because of the increases of all three TOU rates (see section **Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers**).
  - The Delivery Charge to seasonal ratepayers was higher than for typical residential ratepayers because delivering power to remote seasonal properties through forests and around lakes requires more infrastructure, such as poles, lines and transformers, and is therefore more expensive than service to more populated areas.
  - Seasonal ratepayers were surprised by the unanticipated consequence of billing changes after smart-meter installation. For example, before installing smart meters, Hydro One would issue four bills a year to seasonal ratepayers—one based on an actual meter reading carried out by Hydro One staff at the ratepayer's premises, and three based on estimates. After the installation of smart meters, which enable TOU pricing to measure the exact time when electricity is used, seasonal ratepayers began to receive much higher bills in the summer and lower bills in the winter.

At the time of our audit, we noted that Hydro One had been taking some actions to resolve the existing billing issues. For example, Hydro One was improving its training to customer-service staff; providing refund options (a cheque or a credit on account) to ratepayers who were overbilled; waiving late payment charges; and not sending disconnection notices to ratepayers who experienced billing issues caused by Hydro One.

RECOMMENDATION 2

To ensure that the combination of smart meters and time-of-use (TOU) pricing is effective in changing ratepayer electricity-usage patterns to reduce peak electricity demand and related infrastructure costs, and that ratepayers understand the impacts of TOU pricing on their electricity bills, the Ministry of Energy should work with the Ontario Energy Board and/or the distribution companies to:

- evaluate TOU pricing design, including TOU rates, TOU periods and the allocation of the Global Adjustment across the three TOU rates;
- monitor trends in ratepayer electricity consumption to evaluate the effectiveness of TOU pricing over time; and
- disclose the components of the TOU rates (electricity market price and Global Adjustment) separately on electricity bills so that the impact of the Global Adjustment is transparent to ratepayers.

MINISTRY RESPONSE

As established in the *Ontario Energy Board Act, 1998* and prescribed in Ontario Regulation 95/05, the OEB is responsible for setting rates for residential and small business customers on the Regulated Price Plan (RPP), which includes time-of-use (TOU) pricing.

TOU rates continue to evolve as the province balances both system and customer benefits, and as we learn more about how consumers are responding to TOU rates.

Further analysis is under way and the Ministry looks forward to the OEB's planned review of the RPP and TOU pricing that is currently under way.

The OEB's RPP review is timely in that it will build on the robust analysis of the actual impacts of TOU prices in Ontario that have been completed by the OEB and OPA.

OEB RESPONSE

The OEB is undertaking a review of TOU pricing. That review will consider all of the matters identified by the Auditor General, including the structure of the TOU periods, the TOU prices, and the forecasting of the costs and the Global Adjustment to be recovered in those prices. We anticipate that this review will be completed during the OEB's 2014/15 fiscal year. The OEB would be pleased to work with other agencies and with the Ministry regarding any further review of TOU prices that the Ministry may consider appropriate in the circumstances.

RECOMMENDATION 3

To ensure that ratepayer concerns are addressed properly and in a timely manner, and that clear, timely and accurate bills are issued to ratepayers, the Ministry of Energy should work with the Ontario Energy Board, Hydro One and other distribution companies to:

- improve tracking of the nature and details of ratepayer enquiries and complaints to identify and monitor common or recurring concerns;
- better educate ratepayers about the impacts of time-of-use (TOU) pricing and other factors on electricity bills, as well as the root causes of potential metering or billing issues and what is being done to address them; and
- identify and fix any problems with their billing systems and local communication systems on a timely basis, and monitor the performance of those systems over time to reduce ratepayer complaints triggered by these problems.

MINISTRY RESPONSE

In accordance with the *Ontario Energy Board Act, 1998*, the OEB is responsible for protecting the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

In line with these objectives, the OEB has made customer focus one of four principal outcomes for local distribution companies (LDCs) as part of its Renewed Regulatory Framework for Electricity.

The Ministry welcomes the introduction of specific metrics related to customer satisfaction as part of its scorecard to measure and benchmark LDC performance on an annual basis.

In particular, from 2014 on, LDCs will be required to report to the OEB on their effectiveness at addressing customer complaints, customer satisfaction survey results and performance with respect to targets for billing accuracy.

The Ministry will ask the OEB to consider whether any additions or revisions to its new framework are required in light of this recommendation.

HYDRO ONE RESPONSE

Hydro One serves over 1.2 million ratepayers across Ontario and issues over 1 million bills monthly. The implementation of Hydro One's new billing system in May 2013 has led to billing issues for about 6% of its customers. Hydro One has been working to communicate with ratepayers and make them aware of its plans to fix the technical issues and improve customer service. At the time of this audit, approximately 1.8% of customers were impacted. Since February 2014, Hydro One has taken several actions to improve its customer service, including:

- reducing the number of ratepayers who have not received a bill for a prolonged period of time to 0.8%, improved from 5%;
- decreasing the number of ratepayers who have received only estimated bills for a prolonged period of time (currently 1% of Hydro One's customer base);
- introducing a 10-day commitment for resolving customer issues, with a resolution within 10 days or by a promised date;
- changing call-centre training, increasing the number of customer-service-centre agents, and introducing new policies such as interest-free payment plans for customers who have received bills covering long billing periods and waived service charges for ratepayers affected by billing issues;
- adding a new section to Hydro One's website to improve ratepayer understanding of billing and metering issues; and answer ratepayers' common questions on high bills, the impact of cold weather on electricity consumption, meter readings, meter accuracy, smart meters and the smart-meter network;
- enhancing customer call tracking to identify and resolve emerging issues;
- exploring the implementation of a new customer commitment tracking and monitoring solution;
- establishing a Service Champion Advisory Panel; and inviting external experts to provide advice to Hydro One's president and CEO, review Hydro One's customer-service performance, and make performance results public; and
- continuing to fix and monitor the technical problems with its new billing system, improve call centre staff capabilities to address customer service needs, and resolve the associated complaints fairly and promptly by providing payment arrangement options and waiving late payment charges or any other penalties to ratepayers who were affected by these technical problems.

Billing Impacts of Delivery Charge on Ratepayers

There are three major types of costs associated with Smart Metering: capital costs (for meters, communication infrastructure, installation and data systems); ongoing operating costs for meter reading and services; and stranded costs for scrapping old analog meters. These costs are recovered from ratepayers though the Delivery Charge, which is the second largest component of a typical ratepayer electricity bill, and which varies from one distribution company to another, as illustrated in **Figure 7** and **Appendix 2**.

Variations in Delivery Charge between Distribution Companies

As illustrated in **Figure 7**, a typical residential electricity bill varies between $108 per month and $196 per month, depending on where the ratepayer lives and which distribution company provides the service. Of the four categories of charges (Electricity, Delivery, Regulatory and Debt Retirement) that make up the electricity bill, the Delivery Charge accounts for the largest variation in costs among distribution companies, ranging from about $25 a month to $111 a month, with the average at about $44 per month, as shown in **Figure 7** and **Appendix 2**.

In 2012, the Minister of Energy established the Ontario Distribution Sector Review Panel to advise the government on how to improve efficiency in the distribution companies with the aim of reducing the cost to ratepayers of electricity distribution. The panel's research and analysis showed that the current approach to delivering electricity has been costing ratepayers more than it should. In particular, compared to their larger counterparts, smaller distribution companies tended to have higher per capita operating costs, which were passed on to ratepayers through the Delivery Charge line on electricity bills. As a result, ratepayers of smaller distribution companies paid more for their electricity than ratepayers of larger distribution companies. Given the varying sizes of the distribution companies, and their varying Delivery Charge, the panel's key recommendation was to merge the existing distribution companies into eight to 12 larger ones to improve cost-efficiency and ensure price stability, fairness and value for money in the electricity-distribution sector. The panel expected that consolidation would help reduce sector-wide operating costs by 20% in areas such as customer service, billing, facilities maintenance and administration.

However, we noted that the panel excluded the two largest distribution companies with high costs, Hydro One and Toronto Hydro, when comparing the costs of different distribution companies. Given that these two distribution companies have Delivery Charges higher than the provincial average, it would be worthwhile for the Ministry, in conjunction with the OEB, to study the cost implication for ratepayers from consolidation to reduce the variations in distribution-company costs.

Variations in Smart-metering Costs between Distribution Companies

The distribution companies recover all costs associated with the implementation and operation of their smart-metering systems from ratepayers through the Delivery Charge line on electricity bills, as discussed in the section **Variations in Delivery Charge between Distribution Companies**. There are 73 distribution companies across Ontario, each responsible for procuring, installing and operating smart-meter systems. Each distribution company negotiated with different vendors to procure systems for their regions. As a result of the different costs incurred by distribution companies, we noted that the average cost per meter was about $190, but varied significantly, ranging from $81 per meter at one distribution company to $544 per meter at another. Such wide variation was due mainly to geographical issues in service areas and the degree of upfront expenses, such as project-management and system-integration costs. These two factors were particularly significant at Hydro One, Ontario's only provincially owned distribution company.

At the time of our audit, we noted that the costs incurred by Hydro One in implementing its smart-metering project were significant. In December 2006, Hydro One's Board of Directors approved $670 million for the project. By the end of 2013, Hydro One had spent over $660 million (including about $490 million on procurement and installation of smart meters and associated communication systems, and about $170 million on system development, integration and automation), which was about 50% of the $1.4-billion total province-wide implementation cost—and more than the other 72 distribution companies combined (see the section **Ineffective Implementation and Oversight of Smart Metering Initiative**). However, Hydro One installed 1.2 million smart meters, which represents only about 25% of the 4.8 million smart meters installed in Ontario. Of the $660 million spent by Hydro One, our review of the OEB's records noted that about $440 million has yet to be reviewed and approved by the OEB.

Hydro One's high costs were partly the result of installing smart meters and establishing communications infrastructure across its large and diverse geographic service area, which includes a mix of urban, rural and remote regions. Another factor was the high contract fee paid to a private-sector vendor for system integration.

In August 2007, the OEB also noted that the cost incurred by Hydro One at that time to implement its smart-metering project was already high compared to other distribution companies. The OEB indicated that a special comment was warranted with respect to Hydro One's substantial expenditures on a contract for project management with a private-sector vendor. In particular, the OEB reported a concern raised by one stakeholder group: Hydro One had substantial internal management resources and was likely the most experienced distribution company in dealing with big projects, so it was hard to understand why it had to retain the vendor at such a large contract cost. At the time of our audit, we reviewed the contracting process and noted the following:

In March 2005, Hydro One issued a Request for Proposals (RFP) to select vendors in four areas: smart meters, communications, meter-data management, and system integration (including project management and various consulting services associated with back-office functions and operations).

With respect to the system-integration contract, eight vendors bid on the contract, and Hydro One set up an RFP Evaluation Team to assess each proposal. We noted that Hydro One did not effectively manage its vendor-selection process, governance structure and contract costs. Specifically:

- The proposals submitted by different vendors were not comparable, and so it was inappropriate to assess them together. In particular, not all vendors submitted prices up to 2010. When we asked for more details and explanation, Hydro One management said they could provide only speculation and anecdotal responses, because the key employees in the RFP Evaluation Team who worked on the initial stage of the project were no longer with Hydro One. When we interviewed these former employees, they confirmed that, apart from the RFP Evaluation Team's scoring sheet, there was no other documentation on file to explain how the scores were assigned.
- The RFP Evaluation Team selected the system-integration vendor based on several criteria, including price. However, pricing evaluation was not based on the overall contract cost. Hydro One explained that since the smart-metering project would span multiple years based on new technology, the overall contract cost could not be fixed due to the "unknown nature of all the business requirements at the time of the RFP." An appropriate RFP process would require Hydro One to understand and know more about what it wants in its smart metering project, and to specify the requirements for the vendors in sufficient detail so that they could develop an approach to the project. Granting a contract through the RFP process without acquiring enough knowledge about the business requirements could lead to risks of significant cost increases due to change orders. Carrying out a Request for Information (RFI) process, which is designed to collect more information from a broad base of potential vendors prior to the RFP procedure, would help reduce such risks, particularly for a project of this size involving emerging technology.
- In April 2005, Hydro One selected the system-integration vendor. Since then, Hydro One entered into multiple contracts with this same vendor, and approved a number of change orders. The costs associated with these contracts have increased significantly, which in

turn contributed to Hydro One's higher cost per meter than other distribution companies. Specifically:

- At the time of our audit, the total contract cost paid by Hydro One to the vendor exceeded $125 million. Our review of Hydro One's board minutes noted that the board received no specific details on contract fees paid to this vendor. Hydro One explained that the board delegated the responsibility to oversee cost details to Hydro One management. Hydro One also indicated that it managed the contract and project execution according to a program governance plan. However, our review of this plan noted that it was developed by the vendor and did not include Hydro One's board in the governance structure.
- The initial contract set the fee at a maximum of about $1.1 million, and specified that the scope was to support the rollout of 25,000 smart meters, and to continue design, proof-of-concept and planning activities. The contract ended up supporting the deployment of just 2,000 smart meters, but the actual fee paid by Hydro One amounted to $1.7 million, which included additional costs arising from change requests and reimbursements for travel and other expenses.
- Hydro One, as a Crown corporation, is required to follow the government's procurement policy, which says that any contract between the organization and a successful vendor must be formally defined in a signed written document before goods or services are provided. However, Hydro One signed the initial contract with the vendor on April 25, 2006, three months after the vendor had already started work. Similarly, a second contract was signed on August 31, 2006, two months after the vendor had already commenced work.
- After the first two contracts, Hydro One signed multiple contracts with the same vendor from 2007 to 2010 without a competitive process, even though both the initial and second contracts stipulated that Hydro One had the option to look for other suppliers to complete subsequent work. If Hydro One did not use the same vendor again for subsequent work, both the initial and the second contracts specified that Hydro One would have to pay an additional $462,000 and $650,000 respectively that the vendor had initially offered to Hydro One as a discount, and could not use certain products delivered by the vendor for any RFP or other procurement processes in the future. Hydro One explained that the smart-metering project was a multi-phase one, with each phase proceeding on completion of the previous phase and at the sole discretion of Hydro One. Hydro One further indicated that since the initial contract had been awarded through a competitive process, there was no requirement to conduct separate competitive processes for subsequent phases.

Additional Costs of Implementing Smart Metering

Apart from smart-meter capital and operating costs, there were other expenses relating to implementation of Smart Metering, including the disposal of analog meters and the future replacement of smart meters, that will have a significant impact on electricity bills.

The installation of about 4.8 million smart meters in Ontario rendered millions of conventional analog meters obsolete, making it necessary to retire and dispose of them sooner than planned. The distribution companies we consulted said the analog meters they had to scrap were still in good shape and could have been used for another five to 16 more years. The expense of scrapping analog meters became part of the so-called stranded costs, added to the costs of procuring, installing and operating smart-metering systems. The OEB allows distribution companies to fully recover stranded costs from ratepayers through the Delivery Charge on electricity bills. As of January 2011, total stranded costs would be about $400 million, which represents the net book value of the obsolete analog meters as reported in the 2005 OEB implementation plan. As such, this $400 million more reliably captures stranded costs than the $185-million amount in stranded costs that the distribution companies had reported in their smart-meter-cost-recovery applications to the OEB at the time of our audit. In our view, this $185-million amount is incomplete because it represents only the costs the distribution companies are recovering through the application process to the OEB but not the costs that they are recovering through other means, such as writing off the value of their analog meters outright and accelerating the depreciation of their analog meters.

Apart from the stranded cost, another additional cost is related to the replacement of smart meters, which will likely further increase the Delivery Charge on electricity bills because smart meters would be subject to earlier and more frequent replacement than analog meters. The estimated useful life for a typical smart meter is 15 years, compared to 40 years for an analog meter. The distribution companies we consulted said the 15-year estimate is overly optimistic because smart meters:

- are subject to significant technological changes, making it difficult to maintain hardware and software for the first-generation meters, which do not have the advanced functions of newer models;
- have complex features, such as radio communications and digital displays, which are subject to higher malfunction and failure rates;
- are similar to other types of information technology, computer equipment and electronic devices in that they are backed by short warranty periods and require significant upgrades or more frequent replacements as the technology matures; and
- will likely be obsolete by the time they are re-verified as required by the federal agency Measurement Canada every six to 10 years.

Costs relating to replacements will be subject to OEB review and approval. If the OEB does not allow the distribution company to recover these costs from ratepayers, the distribution company will seek recovery through other means (for example, passing the costs on to taxpayers and/or reducing the dividends that the distribution company pays to the municipality). At the distribution companies we visited, we noted cases of mass replacements of smart meters triggered by technological advances and malfunctions. For example:

- In 2013, one large distribution company notified the OEB that 96,000 first-generation smart meters installed in 2006 had to be replaced prior to their normal retirement date to take advantage of improved functionality provided by updated technology. The new meters have 10 times the memory retention of first-generation meters, and provide a "last gasp" function that allows them to detect imminent power outages. The distribution company forecast that 37,000 first-generation meters would be replaced by the end of 2020, and projected a $2.5-million loss on disposal of these older smart meters. The total cost of replacing these meters was set at $11 million.
- In 2012, another large distribution company identified a communication defect in a specific batch of 71,000 smart meters, and had to replace them all regardless of whether they malfunctioned, because they would eventually fail. The distribution company had already replaced about 62,000 of them and expected to complete the job by the end of 2014. From 2013 to April 2014, the distribution company incurred $8.7 million in replacement costs, but it expected to recover at least $2.3 million of that cost from the vendor under the commercial terms of the warranty.

RECOMMENDATION 4

To ensure that the unanticipated costs incurred by distribution companies in implementing the Smart Metering Initiative are justified, and that any significant cost variations among distribution companies are adequately explained, the Ontario Energy Board should perform detailed reviews of distribution-company costs, including an analysis of cost variations for similar services among different distribution companies.

OEB RESPONSE

The OEB has reviewed the prudence of smart-meter costs incurred by most distribution companies through the OEB's hearing process. These reviews took into account the requirements of Ontario Regulation 426/06, the costs incurred by the distribution companies seeking approval and the variations of the costs incurred by different distribution companies. Accordingly, the OEB does not anticipate undertaking additional analysis of those smart-meter costs that have already been reviewed through the OEB's hearing process. However, several distribution companies, including Hydro One, have not yet applied for recovery of all of the smart-meter costs they have incurred. Once those distribution companies apply for such recovery, the OEB will review the prudence of those costs in accordance with the factors set out above.

RECOMMENDATION 5

To improve cost-efficiency of the distribution companies and reduce variations in distribution companies' costs, the Ministry of Energy, in conjunction with the Ontario Energy Board, should formally conduct a cost-benefit analysis into consolidating distribution companies as recommended by the Ontario Distribution Sector Review Panel.

MINISTRY RESPONSE

The Minister of Energy has committed that government will not legislate or force consolidation within the distribution sector. The government is focused on delivering ratepayer savings through voluntary consolidation on a commercial basis and in the best interest of ratepayers.

The government sought input from the local distribution companies (LDCs) to create efficiencies and deliver savings to ratepayers while at the same time positioning the distribution sector to meet the challenges of the future. The government continues to challenge LDCs to do more to improve efficiency and reduce costs for ratepayers.

Hydro One and its large distribution customer base can act as a catalyst for consolidation by seeking acquisition and partnership opportunities. The government expects that Hydro One will only pursue opportunities that are economically viable and in the best interest of ratepayers.

Any change of ownership in the local distribution sector is subject to Ontario Energy Board approval.

OEB RESPONSE

The OEB has undertaken a number of initiatives to improve the cost-efficiency of distribution companies and to address any regulatory barriers to consolidate the distribution companies. The OEB would be pleased to work with the Ministry regarding any further cost-benefit analysis of distribution-company consolidation that the Ministry may consider appropriate in the circumstances.

RECOMMENDATION 6

To ensure that any future project is implemented cost-effectively and in compliance with sound business practices, Hydro One should review and improve its contracting and procurement activities, such as retaining adequate documentation to justify vendor selection and evaluation and acquiring enough knowledge about a project's business requirements before issuing a Request for Proposal, to minimize the risks of significant contract-cost increases.

HYDRO ONE RESPONSE

The Request for Proposal (RFP) process for Hydro One's smart-metering project was completed in April 2005. Subsequent to the RFP process and the Auditor General's audit on Hydro One's Acquisition of Goods and Services in 2006, Hydro One developed an evaluation guideline, which requires documentation of detailed notes to substantiate the evaluation scores.

Hydro One agrees that it is subject to the government's procurement directives. Hydro One has complied with such directives and associated amendments since the first directive was issued in July 2009. In 2009 and 2010, Hydro One also changed its internal policies to comply with the government's travel and expense and procurement directives. For example, Hydro One no longer reimburses its consultants for meals, hospitality or incidentals, and continues to reimburse expenses related to flights, train and car travel and hotel rooms only if such expenses are agreed to in the contracts and pre-approved by Hydro One.

Hydro One also agrees that a Request for Information (RFI) process is a useful tool to assess the market, determine business requirements, and/or estimate project costs. Responses to RFIs contribute to the content of an eventual RFP document. The RFI is a procurement tool that Hydro One now employs.

Smart-meter Data Processing Systems and Costs

Data collection and management is an important component of Smart Metering to ensure that accurate and timely meter-reading data is available from which to prepare TOU-based bills for ratepayers.

In July 2006, the government appointed the Independent Electricity System Operator (IESO) as co-ordinator of the Smart Metering System Implementation Program. A key IESO responsibility was to establish the Meter Data Management and Repository (provincial data centre), to provide a common and central platform for processing, storing and managing smart-meter data to support TOU pricing.

In July 2007, the government designated the IESO as a Smart Metering Entity, making it responsible to manage the development, implementation and operation of the provincial data centre, and to facilitate the integration of smart-meter data within the centre. The aim was to enable distribution companies to bill ratepayers accurately for consumption. The data flow between the distribution companies and the IESO within the smart-metering system is illustrated in **Figure 14**.

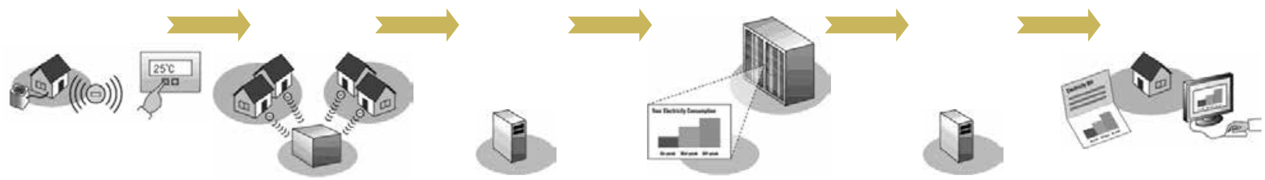
Ratepayers Charged for Redundant or Unused Provincial Data Centre Services

The *Energy Conservation Responsibility Act, 2006*, permits the IESO to recover costs associated with the development, implementation, and operation of the provincial data centre, as well as the integration of the distribution companies into the provincial data centre. In March 2013, the OEB approved an IESO application to recover from all residential and small-business ratepayers the $249-million cost for the period from 2006 to 2017 (including $100 million in actual costs from 2006 to 2012 and the $149-million projected costs from 2013 to 2017) through a new Smart Metering Charge (Charge) of 79¢ a month. This monthly Charge has been included in the Delivery Charge on electricity bills

Figure 14: Smart Metering System and Data Flow in Ontario

Source of data: Independent Electricity System Operator (IESO)

73 Local Distribution Companies			IESO	73 Local Distribution Companies	
Smart Meters	**Data Collector**	**Data Transfer**	**Data Processing***	**Billing System**	**Data Access**
Smart meters installed by a distribution company track hourly electricity usage data.	Data is sent by wireless connection, phone or power line to a regional collector owned by the distribution company.	Regional collector relays data to a system operated by the distribution company.	Provincial data centre collects data from distribution company and calculates electricity usage during on-peak, mid-peak and off-peak hours.	The distribution company receives data from the provincial data centre and prepares electricity bills from its billing system.	Ratepayers have access to their data through electricity bills and online through distribution company's website.



* Almost all of the distribution companies have also used their own systems to process smart-meter data (before transmitting it to, or after receiving it from, the provincial data centre) for billing purposes, as illustrated in the section Duplication of Systems and Costs.

since May 1, 2013, and will continue until October 31, 2018.

About 4.8 million smart meters have been installed by distribution companies across Ontario, but approximately 812,000 of them, or about one in six, have not transmitted any data to the provincial data centre for processing. However, these 812,000 ratepayers still have to pay the monthly Charge of 79¢, totalling about $42.1 million up to October 2018. Specifically:

- In August 2008, one large distribution company implemented its own system to process smart-meter data, with functions similar to the provincial data centre. In April 2009, the Ministry and this distribution company signed a Letter of Understanding allowing the company to use its own system on an interim basis to accelerate the introduction of TOU pricing. The distribution company initially agreed to begin transmitting its smart-meter data to the provincial data centre by the end of 2010. In February 2013, the company deferred its plan for full integration with the provincial data centre to the end of 2015. Currently, this company has about 700,000 ratepayers with smart meters, but still has not transmitted any data to the provincial data centre. While these 700,000 ratepayers have never benefited from the provincial data centre, each still has to pay the 79¢-a-month Charge; they have paid a total of about $7.7 million up to mid-2014, and will pay $28.6 million more by October 2018. On top of the monthly Charge, these ratepayers also cover the cost of the distribution company's own data system.
- Another large distribution company has about 112,000 ratepayers with smart meters, but has not transmitted any data to the provincial data centre due to internal network connectivity issues with the company's smart-metering system. Although these 112,000 ratepayers have never benefited from the provincial data centre, they must also pay the monthly Charge of 79¢—a total of $1.2 million up to mid-2014 and another $4.6 million by October 2018.

Duplication of Systems and Costs

The *Energy Conservation Responsibility Act, 2006* and Ontario Regulation 393/07 designated the IESO as the Smart Metering Entity, with "exclusive authority" to carry out the following functions through development and operation of the provincial data centre:

- collect, manage and store meter data;
- perform validation, estimating and editing activities to identify and account for missed or inaccurate meter data;
- operate one or more databases to facilitate collecting, managing, storing and retrieving meter data; and
- prepare data that is ready for use by distribution companies to bill ratepayers.

In February 2007, the Program Definition Document, which established the responsibilities for the Ministry and the IESO in the design and delivery of provincial data centre functionality, also stated that "centralization of the [provincial data centre] functions will ensure a standardization of data validation, estimating and editing processes across the province and facilitate a cost-effective implementation of such processes."

However, when the IESO began developing the provincial data centre in 2007, some distribution companies had already procured and begun to install their own smart meters and associated systems, which varied from one company to another. As a result, we noted that the use of the provincial data centre as a central system has not been cost-effective, because most of the distribution companies have used their own systems to process smart-meter data (before transmitting it to, or after receiving it from, the provincial meter data management system) for billing purposes.

In interviews with and surveys of distribution companies, we found that 96% have been using their own systems to process smart-meter data, and 88% said their own systems and the provincial data centre perform similar functions, resulting in redundancy. For example, before transmitting data to the provincial data centre, the distribution companies use their systems to perform data validation, estimating and editing services—all key functions of the provincial data centre.

The costs of this duplication—one system at the provincial level and another locally—are all being passed on to ratepayers. The monthly operating cost associated with each distribution company's own system, about 21¢ per meter on average, is being borne by ratepayers on top of the 79¢ monthly Smart Metering Charge (see the section **Ratepayers Charged for Redundant or Unused Provincial Data Centre Service**).

Based on our review of comments submitted by distribution companies and stakeholders in June 2006, during the Ministry's consultation, we noted consistent concern about system duplication. Examples of comments:

- "Centralization of part of the customer billing functions and accountabilities as proposed are unnecessary and incomprehensible given the complexities and issues that give rise to exceptions in determining meter reading and billing quantities on a daily basis."
- "Vesting that responsibility [validation, editing and estimating (VEE) function of smart-meter data] in the[provincial data centre] is tantamount to duplication of efforts and operational inefficiencies that will lead, in turn, to incremental costs."
- "The customers will call us when they have questions or problems. It is critical that the [local distribution companies] have free and open access to our customer data, the right to archive data for billing and operational usage, and continue to be the sole point of contact for our retail customers."
- "[Local distribution companies] have never been given a reasonable explanation as to why the data needs to be gathered, stored and redistributed back to [local distribution companies] from such a massive central storage base… Customers will be calling their local distributors for information that will be

primarily housed at a central [provincial data centre].”

- “Validation, editing and estimating (VEE) will be performed centrally. This central assumption is of great concern to [local distribution companies]. As the [local distribution company] has the local customer relationship and knowledge, it is in the best position to know the unique specifics of their individual customers and therefore provide the most accurate edits and estimations of customer data.”
- “As the LDCs’ Customer Information System (CIS) is the source of the relationship between customer, location and meter, CIS will now also have to manage that relationship including the new [provincial data centre]. This will require programming changes within CIS systems… This approach seems to be one which would result in significant duplication of data in order to maintain these relationships.”

Significant System Development and Integration Challenges

Tight and aggressive timelines set by the government, as noted in the section **Governance and Oversight of Planning and Implementation**, along with the complex structure of Ontario’s electricity sector involving numerous distribution companies, have created significant challenges in the system-development and integration aspects of implementation of Smart Metering.

Aggressive Smart Metering Implementation Timelines

According to the OEB’s 2005 implementation plan for Smart Metering, many stakeholders expressed concern over an aggressive timetable that could lead to mistakes and higher costs. The OEB plan also warned that Smart Metering was both challenging and complex, requiring an intense and well-co-ordinated effort between key players over several years, plus the co-operation of ratepayers.

We found that aggressive timelines created challenges in the development of the provincial data centre and its integration with different systems at the distribution companies. For example, senior IESO management indicated that the timelines were tight from the start and that development of the provincial data centre was a large undertaking being done too quickly, especially in 2007 and 2008, when the IESO encountered software and technical issues. The IESO expressed concerns about the tight timelines to the Ministry, but there was no change to the original summer 2007 deadline. The IESO did not meet that deadline, and delivery of the provincial data centre was delayed to March 2008. Some distribution companies had started installing smart meters for ratepayers prior to 2007. The provincial data centre was not ready to process smart-meter data for TOU pricing when the first smart meter went online.

The OEB also indicated that 40 out of 73 distribution companies applied for extensions to their mandated implementation dates of TOU pricing due to operational or technical problems, including delays in integrating with the provincial data centre and data-quality issues with certain smart meters.

In addition, 40% of the distribution companies we consulted ranked “implementation timelines” as one of the top three challenges (see **Appendix 1**). Some of the distribution companies commented that:

- “The province should have provided more time for testing and implementation of smart meter technology as opposed to rushing unproven technology into service.”
- “Integration with the [provincial data centre] presented challenges as the system design and timelines continued to evolve during the implementation.”
- “Meeting timelines was difficult due mainly to integration challenges.”
- “Implementation timelines were aggressive given all the testing and paper-work that was required.”

Complicated Structure of Electricity Sector for Smart Metering Implementation

In other jurisdictions, mass deployment of smart meters was carried out by only a few distribution companies, or even just one. The challenge in Ontario was that 73 different distribution companies were each responsible to purchase, install, operate and maintain smart meters, as well as to bill ratepayers.

The fact that a relatively large number of distribution companies operate in Ontario's electricity sector has made it challenging to ensure cost-efficient implementation of Smart Metering, in part because it required significant system integration between the provincial data centre and different smart-metering systems as well as billing systems at individual distribution companies. To ensure compliance with system interface and data-transfer requirements, each distribution company had to upgrade its existing systems, or acquire new ones, and perform a series of hardware and software tests. Specifically, we noted that:

- Seventy-five per cent of the distribution companies we consulted ranked "data management and system integration" as one of the top three challenges, and 83% said it was difficult and costly to integrate their systems with the provincial data centre (see **Appendix 1**).
- Sixty per cent of distribution companies indicated that changes to the provincial data centre required them to implement "frequent system changes and upgrades." The IESO said that between 2009 and 2012, three major changes were made to the provincial data centre to correct defects, deliver new functions, and address the issue flagged by Measurement Canada (see section **Non-compliance with Measurement Canada's Data Requirements**). Apart from the three major changes, the provincial data centre was also modified during 2008 and 2009 to support changes to distribution company systems and operating practices. Distribution companies that tracked these costs reported spending a total of about $47 million to change their internal systems to ensure proper integration and compatibility with the provincial data centre (see **Figure 15**). Some of the distribution companies commented as follows:
  - "Integration with [the provincial data centre] required multiple upgrades and ongoing testing beyond testing required with the IESO."
  - "Testing with the [provincial data centre] was a very onerous task."
  - "Significant time and effort went into systems integration to ensure proper data flow between the [provincial data centre] and the distribution companies."
  - "This was a costly and time-consuming exercise to integrate the distribution companies' systems and the [provincial data centre]."

Figure 15: System-related Costs Incurred by Local Distribution Companies
Prepared by the Office of the Auditor General of Ontario

Date	Cost Description	Approx. Cost[1] ($ 000)	Report Section (if applicable)
2006–2013	Upgrading local systems to enable the implementation of TOU pricing	47,000[2]	Significant System Development and Integration Challenges
2006–2013	Developing web presentment portals to allow ratepayers to access their electricity use and billing data online	1,100	
2010–2012	Fixing local systems to comply with Measurement Canada's requirements	800	Non-compliance with Measurement Canada's Data Requirements

1. Amount understated because some of the distribution companies we interviewed and surveyed did not separately track these costs. Many of the distribution companies we consulted treated these smart metering-related costs as their normal operating costs and recovered these costs through their regular rate applications to the OEB rather than through their smart-meter-cost-recovery applications.
2. About $40 million of this $47-million amount was incurred by Hydro One.

Aggressive implementation timelines and a complex electricity sector made it challenging to implement Smart Metering smoothly and cost-effectively.

Insufficient Oversight of Provincial Data Centre Costs and Services

The IESO initially contracted in December 2006 with a private-sector vendor, following a competitive bidding process, for the development, implementation and operation of the provincial data centre. That initial contract was for the five years from December 2006 to March 2012, with an option for another two years to March 2014, which it exercised. In December 2012, following a competitive bidding process, the IESO entered into a new contract with the same vendor for another five years, to March 2019, with an option to extend for five more years, to March 2024. The IESO has already paid this vendor about $81.7 million for the period from January 2007 to March 2013. Apart from using personnel supplied by this vendor and internal staff, the IESO incurred about $16 million in costs by the end of 2013 for other consultants to develop, implement and operate the provincial data centre.

Contract Terms for Operating Fee of Provincial Data Centre Not Clear

Our review of the contract fee paid by the IESO to the vendor for operating the provincial data centre showed that the average annual fee of $13.4 million for the two-year extension period between 2012 and 2014 was almost double the $6.8-million-a-year rate of the original contract period for the five previous years.

The IESO attributed a portion of the fee increase to the additional costs associated with the changes made to the provincial data centre. However, we noted that these additional costs were mainly incurred prior to 2012, before the two-year extension, to deal with major changes made to the provincial data centre. The IESO also attributed a portion of the fee increase to the higher number of smart meters. However, the government had set the target of installing smart meters for all residential and small-business ratepayers, so the IESO should have been aware of the number of smart meters that had to be installed.

We noted that the IESO and the vendor negotiated and agreed upon the higher contract fee as a result of the ambiguity of contract terms for the two-year extension period. Specifically, when the IESO prepared in June 2011 to exercise the two-year extension option under the original contract, it discovered an error that resulted in an under-estimation of the cost projection for the two-year extension period by $13.9 million. As a result, IESO management informed the Board of Directors that the error stemmed from an amendment that failed to clarify the contract fee applicable to the two-year extension. IESO management also informed its legal counsel that this was an oversight on the part of the vendor, the IESO and their counsels, and that since the vendor had incurred losses on the contract, the "ambiguity around contract extension offered opportunities to improve the vendor's commercial position and stem their losses going forward."

Continued to Contract for Service Not Being Used

Under the original contract, the IESO required the vendor to provide Interactive Voice Response (IVR) service that enables ratepayers to check their electricity usage by telephone. The IVR service was available for use in March 2008, when the provincial data centre began operating. However, only two of the 73 distribution companies chose to register and configure themselves for IVR, and they reported only limited ratepayer use of the service. For example, only 25 ratepayers at these two distribution companies used IVR from February 2012 to March 2013. Even though there has been very little use of IVR since its start-up in March 2008, the IESO still included IVR in the new contract signed with the vendor in December 2012.

While almost 80% of the distribution companies integrated their systems with the provincial data centre in 2011 and early 2012, the IESO indicated that it did not have sufficient information on the actual use of the IVR service prior to 2013. As such, the IESO did not retire IVR until September 2013, and it consequently negotiated a credit of $390,000 to be applied against future deliverables from this vendor. Adequate and proper monitoring of service usage on a timely basis would have terminated the IVR service sooner and eliminated the associated cost, which was not specified in the contracts and could not be estimated.

RECOMMENDATION 7

To ensure that ratepayers are not burdened with the duplicated and ongoing costs of system development and integration, the Ministry of Energy should work with the Independent Electricity System Operator (IESO), the Ontario Energy Board (OEB) and the distribution companies to re-evaluate options around operating the provincial data centre and/or having separate local systems at individual distribution companies in order to determine the cost-effectiveness of various options and avoid continued duplication of systems and costs.

MINISTRY RESPONSE

The Ministry has ensured that the necessary regulatory framework, in particular Ontario Regulations 393/07 and 426/06, is in place to restrict cost duplication for services which are within the exclusive authority of the Meter Data Management and Repository.

The Ministry will continue to investigate opportunities to build on the value already provided by the provincial data centre.

IESO RESPONSE

If requested by the Ministry of Energy, the IESO will work with the Ministry and the OEB to encourage distribution companies' compliance with existing regulation and reduce the reported duplication of the functions that the IESO has exclusive authority over, and that are fulfilled by the provincial data centre.

Similarly, if requested by the Ministry of Energy, the IESO will work with the Ministry and distribution companies to identify and evaluate opportunities for leveraging existing investments and economies of scale of the provincial data centre in order to reduce the operating costs of distributors and costs to the ratepayer.

OEB RESPONSE

The OEB would be pleased to work with the Ministry of Energy and others in any assessment that the Ministry may initiate in respect of options regarding the cost-effective use of the resources of the provincial meter data management system and the local distribution systems.

RECOMMENDATION 8

To ensure that any future province-wide project involving the complex electricity distribution sector is implemented cost-effectively, the Ministry of Energy should work with the relevant electricity sector organizations to set appropriate and reasonable implementation targets and timelines in order to minimize the costs and risks associated with system development and integration for numerous distribution companies.

MINISTRY RESPONSE

The smart meter and time-of-use (TOU) rollout was completed via a partnership approach. Each organization, namely the Ministry, the IESO, the OEB and local distribution companies were responsible for certain aspects of the rollout, and significant consultation took place along the way.

The Ministry will ensure that projects in the electricity distribution sector are rolled out in a prudent, collaborative and cost effective manner.

Smart-meter Data Accuracy and Quality

To minimize billing estimates and adjustments, as well as ratepayer complaints, smart-meter data has to be processed accurately and completely to produce correct and timely billing data.

Non-compliance with Measurement Canada's Data Requirements

Measurement Canada is the federal agency responsible for ensuring that ratepayers receive fair and accurate measurement in transactions involving goods and services, including measurement of electricity consumption and billing. Generally, electricity consumption and billing can be measured using two types of smart-meter data: "register read" or "interval read."

- "Register read," recorded by both analog and smart meters, is the meter's internal memory or external display showing the total cumulative consumption from the date it was installed, similar to a car odometer's record of kilometres travelled. Prior to installing smart meters, distribution company staff manually read analog meters by visiting ratepayer premises. The cumulative meter reading on electricity bills should match the numbers on the meters.
- "Interval read" is logged only by a smart meter, and is a time-based record of electricity usage (hourly or shorter period) by ratepayers.

Measurement Canada requires the cumulative meter reading to be used in calculating the billing amount, and to be displayed on both the meter and the bill. These requirements ensure transparency by providing information on electricity bills that enable ratepayers to look at their meter's display and then reconcile it to the amounts on their bills. However, Measurement Canada advised both the IESO and the Ministry in November 2009 that its requirements were not being met in Ontario, because the cumulative meter reading from smart meters was not being captured by the provincial data centre or by the distribution companies' systems. In January 2010, Measurement Canada reiterated its concerns and instructed the IESO to take corrective action by January 1, 2012. Consequently, both the IESO and the distribution companies changed their systems to address Measurement Canada's concern. The IESO spent $13.7 million to make necessary adjustments to the provincial data centre.

Apart from the IESO, the distribution companies also incurred costs to fix the problem at their end. In August 2010, the IESO indicated to the media that only about 150,000 ratepayers at five distribution companies were affected by this issue. However, we noted at the time of our audit that, in fact, all distribution companies were affected and had incurred additional costs to fix the problem. Of the distribution companies we consulted, only 20 of them tracked their costs for this—a collective total of more than $800,000 to correct the problem (see **Figure 15**). One distribution company noted that the Measurement Canada issue has "negatively impacted the costs associated with [provincial data centre] integration." Another said the billing systems of all distribution companies "had to be re-engineered to remove 'register reads' when the [provincial data centre] was first implemented and then re-engineered again to put the 'register reads' back … there really seemed to have been a misunderstanding with the Ministry or IESO as the system should have been designed to show 'register reads' right from the beginning."

Questionable Quality and Usefulness of Meter-reading Data

Several limitations in processing smart-meter data by the provincial data centre and the business processes at the distribution companies have affected the quality and usefulness of smart-meter data. For example:

- When distribution companies change or replace meters, they must follow a proper business process that requires them to send two sets of consumption data to the provincial data centre: one set from the old meter and one from the new. Given that some distribution companies did not follow this process, there is no guarantee of the quality and completeness of data they submitted to the provincial data centre, creating a risk that incorrect billing data could be generated.

- Not all smart meters are equipped with technology to notify the provincial data centre when power outages occur. The Ministry also indicated that the provincial data centre is not intended to have a real-time outage management function to help identify blackouts. As a result, ratepayers who lose power during outages could still receive electricity bills based on estimates made by the provincial data centre or the distribution companies. In December 2013, for example, a severe ice storm caused massive power outages in southern Ontario. Based on our review of usage data from one large distribution company affected by the blackouts, some ratepayers with no power still had to pay electricity bills based on estimates of their historical consumption patterns, and the distribution company had to correct the bills in subsequent billing periods.
- Almost all distribution companies have their own systems as noted in section **Duplication of Systems and Costs**. Apart from using these internal systems to process smart-meter data, companies also use it to query and retrieve usage data for ratepayers and for internal analysis. According to half the distribution companies we consulted, they do this because the provincial data centre has limited capabilities for data retrieval and querying. In August 2013, the IESO also reported to its Board of Directors that the provincial data centre was able to manage data queries during its early stage of implementation, but it was not designed to support the expected increases in volume of data-retrieval requests. This has, in turn, reduced the value and usefulness of the provincial data centre, which had been expected to facilitate storage and retrieval of meter data when it was first developed.

RECOMMENDATION 9

To ensure the accuracy, quality and usefulness of smart-meter data, the Independent Electricity System Operator should:

- work with the distribution companies to review the limitations and the billing problems associated with the provincial data centre and the distribution companies' business processes, including improving the procedures of processing smart-meter data during meter replacements and power blackouts, as well as enhancing the data retrieval and querying capability of the provincial data centre; and
- educate the distribution companies about the proper business processes that have to be followed.

IESO RESPONSE

The IESO has provided training sessions for all distribution companies on processing meter replacements and power blackouts within the provincial data centre. The IESO will provide additional training sessions and assistance to those distribution companies that need such training to improve the procedures of processing smart-meter data.

Subsequent to the audit, the IESO enhanced the data retrieval and querying capability of the provincial data centre. Also, the IESO and the Ministry have been working together to develop a business case for a project that will support the evolving needs for data access and retrievals for research and analysis purposes.

Smart-meter Security and Safety Risks

The expanding use of smart meters has led to questions and concerns about possible security risks relating to privacy, and safety risks associated with fire hazards. As part of our audit, we examined these concerns in Ontario.

Insufficient Security and Access Controls on Meter-reading Data

The ability of smart meters to track electricity use on an hourly basis for residential and small-business ratepayers has raised security and privacy concerns regarding unauthorized access to and use of smart-meter data. Smart meters enable the collection of massive amounts of personal electricity-use data, allowing ratepayers and distribution companies—as well as anyone else with access to the data—to see exactly what makes up a ratepayer's electricity use. The smart-meter data could reveal when people are out, daily routines and changes in those routines. As a result, electricity-use patterns could be mined, for example, for marketing and advertising purposes.

In Ontario, about 800 distribution company employees and/or their agents have access to specific functions in the provincial data centre that include viewing and editing meter data through an encrypted interface from any computer connected to the Internet. The IESO's existing controls to prevent and detect unauthorized data access include an annual audit of the provincial data centre by external auditors and an annual risks-and-controls assessment by IESO staff. However, we noted that data security could be improved further. Specifically:

- The provincial data centre automatically grants access to users through a login process that requires a name and password. However, no additional authentication code is required. Based on our research, and consultation with an independent expert in information security and smart metering, the best practice for more secure remote access of privacy-sensitive information is two-step verification. This requires users to provide an authentication code generated by a security device issued to them, in addition to user name and password.
- The IESO has engaged external auditors to conduct an annual audit to provide reasonable assurance that its controls over the provincial data centre are suitably designed and operate effectively. Since this audit is not designed to cover the distribution companies, it is limited to provincial data centre operations and controls specified by the IESO. We noted that data from the provincial data centre could still be exposed to potential security risks at the distribution-company level because:
  - As noted in the section **Duplication of Systems and Costs**, almost all distribution companies we consulted use their own systems to process smart-meter data. Also, about 85% of them indicated that they have not performed any Privacy Impact Assessment (PIA), a formal risk-management tool used to identify the actual or potential effects that a proposed or existing system may have on ratepayer privacy. The PIA is considered a "best privacy practice" for organizations with significant existing or new systems containing personal information.
  - Our review of a sample of 200 staff at different distribution companies who had access to the provincial data centre found that eight who had left the distribution companies did not have their access revoked in a timely manner. The IESO indicated that it is up to distribution companies to advise it when access rights need to be modified or ended. The IESO also said it does not have the jurisdiction, responsibility or ability to review the appropriateness of users to whom distribution companies wish to grant access. Therefore, there

could be security risks at the distribution-company level that the IESO was not aware of and over which it had no control.

Lack of Tracking and Monitoring of Smart Meters-related Fire Incidents

At the time of our audit, we found instances of Ontario ratepayers reporting fires arising from smart meters. From our research, we also noted that other jurisdictions, such as British Columbia, Saskatchewan and Pennsylvania, also reported cases of smart meters catching fire. However, no accurate or complete information on smart meters-related fires was available in Ontario to determine the scope and extent of the problem across the province. Specifically:

- The Office of the Fire Marshal (OFM), Ontario's principal adviser on fire protection policy and safety issues, indicated that it is aware of fires involving smart meters in Ontario, elsewhere in Canada, and in the United States. However, some distribution companies and fire departments do not report such cases to the OFM, so more information is needed to assess the extent of the problem in Ontario. From May 2011 to March 2013, for example, the OFM recorded 14 fires involving either meters or the bases on which they were mounted. However, the OFM indicated that its incident-reporting system could not specifically identify what type of device was involved—analog or smart meter—because it did not collect specific details about the meters. Based on anecdotal evidence, the OFM identified three possible root causes for the fires:
  - old meter base connections may have been loose or otherwise unfit for a seamless exchange to a new smart meter;
  - new smart meters may have been improperly installed; or
  - new smart meters may have had defects that caused electrical failures or misalignment with the old meter base.
- The Electrical Safety Authority (ESA), the agency with a mandate to enhance public electrical safety in Ontario, is delegated by the government to be responsible for the regulation that applies to meter installation. Any meter failure resulting from incorrect installation by the distribution company falls under the ESA's regulatory oversight. In February 2007, and again in October 2012, the ESA indicated that it has been aware of potential fire risks in smart meters, and incidents of property damage involving smart meters and/or meter bases. To address these concerns, the ESA surveyed the distribution companies, asking them to provide information on such incidents. However, the ESA indicated that it has not received sufficient information to conclude on the severity of the issue or the types of meters causing problems. Due to recent smart meters-related fires in Saskatchewan, the ESA started reviewing those incidents in the summer of 2014 to determine if there could be any concerns in Ontario.

The federal Industry Canada department oversees the certification of radio communication devices, including smart meters, which must be tested and certified against Industry Canada standards before they can be sold in this country. At the provincial level, the ESA acts on behalf of the Ontario government, with specific responsibility for electrical safety. As part of its mandate, the ESA administers the Ontario Electrical Safety Code and regulations associated with electricity-distribution-system safety, electrical product safety and licensing of electricians. However, there has been a lack of clarity on the safety standards relating to smart meters at the provincial level. Specifically:

- The ESA indicated that according to an Ontario Electrical Safety Code bulletin in May 2012, federal legislation does not give ESA any jurisdiction over revenue billing devices (i.e., smart meters and associated transformers) and does not require the revenue billing devices to be approved provincially as required by the Canadian Electrical Code or Ontario Electrical Safety Code.

- The ESA further noted that the Ontario Electrical Safety Code applies to meter bases and mounting devices, but not to revenue billing devices such as the actual smart meters. Therefore, smart meters and associated transformers are deemed acceptable if they have an approval number provided by Measurement Canada, a federal agency. However, we noted that Measurement Canada is mandated to ensure the integrity and accuracy of measurement, including electricity consumption and billing data, but not the safety, of measuring devices such as smart meters.

Insufficient tracking and monitoring of smart meters-related fire incidents has made it difficult to determine the scope and extent of the problem across the province as well as to address the problem accordingly, creating safety risks in Ontario.

RECOMMENDATION 10

To ensure that smart-meter data is processed and stored securely, the Independent Electricity System Operator should work with the distribution companies to improve their system and data-security controls in order to prevent and detect unauthorized access to smart-meter data.

IESO RESPONSE

Subsequent to the audit, the IESO introduced new capabilities in June 2014 to help distribution companies manage their users' access to the provincial data centre. The IESO provides the distribution companies with additional information that allows them to identify required changes to their users' access permissions. Based on this additional information, the distribution companies are to notify the IESO of any necessary changes.

In addition, the IESO will review the data-security controls in place at the IESO and the controls that should be in operation at the distribution companies to prevent and detect unauthorized access to smart-meter data. The IESO will also work with the distribution companies to review the "Building Privacy into Ontario's Smart Meter Data Management System" paper published by the IESO and the Information and Privacy Commission of Ontario.

RECOMMENDATION 11

To ensure that potential fire risks of smart meters are addressed appropriately and in a timely manner, the Ministry of Energy should work with relevant entities, such as the distribution companies, the Office of the Fire Marshal and the Electrical Safety Authority, to track and monitor information on smart meter-related fire incidents so as to identify and understand their causes in Ontario.

MINISTRY RESPONSE

The Ministry has not received information from the appropriate authorities or local distribution companies (LDCs) to indicate that there is a safety risk with smart meters in Ontario.

The Ministry will support efforts by the appropriate entities such as the Office of the Fire Marshal, the Electrical Safety Authority and LDCs to ensure that any concerns or incidents related to electricity meter safety are tracked and monitored accordingly.

The Ministry continues to monitor the concerns and actions related to meter safety in Saskatchewan and consider any implications for Ontario.

Appendix 1—Questions to and Responses from Distribution Companies in Ontario

Prepared by the Office of the Auditor General of Ontario

Selected Questions	Responses: % of Distribution Companies Responded "Yes"	Responses: % of Distribution Companies Responded "No"
Did your distribution company realize any net savings in operations since implementing the Smart Metering Initiative?	5	95
Did your distribution company conduct any study to examine the bill impact since the implementation of smart meters and time-of-use (TOU) rates?	9	91
Did your distribution company conduct any study to examine the changes of electricity consumption since the implementation of smart meters and TOU rates?	0	100
Does your distribution company have a system, performing similar functions as the central Meter Data Management and Repository, to process smart meter data?	96	4
Did your distribution company perform any Privacy Impact Assessment when implementing the Smart Metering Initiative?	15	85

	% of Distribution Companies Indicated as Concerns
Please indicate your distribution company's concerns with the Meter Data Management and Repository (provincial data centre)	88% – Redundant functionality with the systems at distribution company
	83% – Difficult and costly to integrate distribution companies' systems with the Meter Data Management and Repository
	60% – Frequent changes and upgrades of the Meter Data Management and Repository
	50% – Limited capacity or capability for data retrieval and query

	% of Distribution Companies Ranked as Top 3 Challenges
Please rank the challenges that your distribution company has faced in implementing the Smart Metering Initiative.	75% – Costly data management and system integration
	44% – Lengthy procurement process
	40% – Tight implementation timeline

	% of Distribution Companies Indicated as Top 3 "High Volume" Complaints
Please indicate the volume (High/Low) of ratepayer complaints relating to smart meters and TOU pricing since the implementation of Smart Metering Initiative in your distribution company.	51% – Increased bills with no savings
	33% – Limited understanding and information on TOU pricing
	24% – Limited or no ability to change electricity consumption

Appendix 2—Delivery Charge on Monthly Electricity Bill by Distribution Company[1]

Source of data: Ontario Energy Board

Distribution Company	Delivery Charge ($)
1. Algoma Power Inc.	59.4
2. Atikokan Hydro Inc.	65.5
3. Bluewater Power Distribution Corporation	45.8
4. Brant County Power Inc.	40.8
5. Brantford Power Inc.	31.8
6. Burlington Hydro Inc.	40.1
7. Cambridge and North Dumfries Hydro Inc.	36.5
8. Canadian Niagara Power Inc. (Fort Erie)[2]	52.6
Canadian Niagara Power Inc. (Port Colborne Hydro Inc.)[2]	53.8
9. Centre Wellington Hydro Ltd.	41.6
10. Chapleau Public Utilities Corporation	53.2
11. COLLUS PowerStream Corp.	34.9
12. Cooperative Hydro Embrun Inc.	39.7
13. E.L.K. Energy Inc.	30.9
14. Enersource Hydro Mississauga Inc.	36.8
15. Entegrus Powerlines Inc.	41.0
16. EnWin Utilities Ltd.	41.6
17. Erie Thames Powerlines Corporation	44.2
18. Espanola Regional Hydro Distribution Corporation	51.1
19. Essex Powerlines Corporation	43.6
20. Festival Hydro Inc. (Hensall)[2]	45.0
Festival Hydro Inc. (Main)[2]	45.6
21. Fort Frances Power Corporation	36.2
22. Greater Sudbury Hydro Inc.	37.9
23. Grimsby Power Incorporated	40.1
24. Guelph Hydro Electric Systems Inc.	41.9
25. Haldimand County Hydro Inc.	57.3
26. Halton Hills Hydro Inc.	39.0
27. Hearst Power Distribution Company Limited	31.7
28. Horizon Utilities Corporation	40.9
29. Hydro 2000 Inc.	43.6
30. Hydro Hawkesbury Inc.	28.0
31. Hydro One (Low Density)[2,3]	110.6
Hydro One (Medium Density)[2,3]	69.5
Hydro One (Urban High Density)[2,3]	54.2
32. Hydro One Brampton Networks Inc.	35.6
33. Hydro Ottawa Limited	40.1
34. Innisfil Hydro Distribution Systems Limited	49.6
35. Kenora Hydro Electric Corporation Ltd.	37.3
36. Kingston Hydro Corporation	41.4
37. Kitchener-Wilmot Hydro Inc.	35.0
38. Lakefront Utilities Inc.	36.7
39. Lakeland Power Distribution Ltd.	53.4
40. London Hydro Inc.	38.3
41. Midland Power Utility Corporation	48.7
42. Milton Hydro Distribution Inc.	40.3
43. Newmarket-Tay Power Distribution Ltd. (Newmarket)[2]	41.7
Newmarket-Tay Power Distribution Ltd. (Tay)[2]	24.9
44. Niagara Peninsula Energy Inc. (Niagara)[2]	39.6
Niagara Peninsula Energy Inc. (Peninsula)[2]	42.7
45. Niagara-on-the-Lake Hydro Inc.	41.8
46. Norfolk Power Distribution Inc.	53.1
47. North Bay Hydro Distribution Limited	40.4
48. Northern Ontario Wires Inc.	51.2
49. Oakville Hydro Electricity Distribution Inc.	43.5
50. Orangeville Hydro Limited	42.3
51. Orillia Power Distribution Corporation	41.3
52. Oshawa PUC Networks Inc.	33.8
53. Ottawa River Power Corporation	36.5
54. Parry Sound Power Corporation	61.0
55. Peterborough Distribution Incorporated	37.4
56. PowerStream Inc. (Barrie)[2]	35.5
PowerStream Inc. (South)[2]	35.1
57. PUC Distribution Inc.	31.7
58. Renfrew Hydro Inc.	37.5
59. Rideau St. Lawrence Distribution Inc.	43.1
60. Sioux Lookout Hydro Inc.	55.0
61. St. Thomas Energy Inc.	39.8
62. Thunder Bay Hydro Electricity Distribution Inc.	33.3
63. Tillsonburg Hydro Inc.	38.6
64. Toronto Hydro-Electric System Limited	46.9
65. Veridian Connections Inc. (Gravenhurst)[2]	52.8
Veridian Connections Inc. (Main)[2]	38.7
66. Wasaga Distribution Inc.	27.3
67. Waterloo North Hydro Inc.	38.0
68. Welland Hydro-Electric System Corp.	41.9
69. Wellington North Power Inc.	50.3
70. West Coast Huron Energy Inc.	55.2
71. Westario Power Inc.	43.8
72. Whitby Hydro Electric Corporation	44.4
73. Woodstock Hydro Services Inc.	45.3

1. This list of 73 distribution companies was based on 2013 Yearbook of Electricity Distributors issued by the OEB. The Delivery Charge data was based on 2014 data from the OEB website.
2. These distribution companies with larger geographic coverage have different Delivery Charge in different regions within their service areas.
3. Hydro One's Delivery Charge varies, depending on the location of ratepayers and the number of ratepayers in an area. The fewer people in the area, the higher the cost of delivering power to that area.

DRA
DIVISION OF RATEPAYER ADVOCATES

PUBLIC/REDACTED

Case Study of Smart Meter System Deployment

Recommendations for Ensuring Ratepayer Benefits

March 2012

About DRA

The Division of Ratepayer Advocates (DRA) is an independent consumer advocacy division within the California Public Utilities Commission (CPUC) that represents the customers of California's investor-owned utilities. DRA's statutory mission is to obtain the lowest possible rates for utility service consistent with safe and reliable service levels. In fulfilling this goal, DRA also advocates for customer and environmental protections.

Acknowledgements

William Dietrich
Camille Watts-Zagha

Chris Danforth – Supervisor/Manager
Cheryl Cox – Policy Advisor
Linda Serizawa – Interim Deputy Director
Joe Como – Acting Director

Cover Design by Karen Ng

PUBLIC/REDACTED

Case Study of Smart Meter System Deployment

Recommendations for Ensuring Ratepayer Benefits

by

Karin Hieta
Valerie Kao
Thomas Roberts

March 2012

This page left intentionally blank.

Table of Contents

This page left intentionally blank.

Executive Summary

This case study is an examination of Southern California Edison's (SCE) "SmartConnect" Advanced Metering Infrastructure (AMI), or smart meter program, to date. The report presents key findings stemming from the Division of Ratepayer Advocate's (DRA) review of cost requests thus far. DRA supported the use of AMI to the extent that it can provide net benefits to customers as projected when approval was granted by the California Public Utilities Commission (CPUC). DRA intends for this report to alert the CPUC to the challenges of tracking AMI costs and benefits and recommends regulatory actions be taken, if necessary, to ensure AMI systems statewide provide a net benefit to customers.

DRA reviewed SCE requests for SmartConnect-related cost recovery in multiple CPUC proceedings and compared them to the costs and benefits estimated in SCE's approved SmartConnect business case, which forecasted costs for its AMI program. DRA also evaluated progress toward the CPUC-adopted estimate of $9 million in lifetime net benefits for SCE customers, which should result in a net reduction in customer bills as a result of smart meter deployment.[1] This version of the report blacks out any confidential data in tables and text.

SmartConnect was approximately 40% deployed during the discovery phase of this study,[2] and only three years of a 24 year program had been completed. Therefore, this report does

[1] The $9 million figure is the result of a present value revenue requirement (PVRR) analysis. SCE also estimated $295 million in societal benefits reflecting reduced energy theft and increased meter accuracy, which parties accepted as reasonable but agreed not to include in the business case (i.e., for purposes of determining cost-effectiveness).

[2] As of January 31, 2012, deployment was approximately 78% complete.

not attempt to offer a conclusion as to the final net cost or net benefit of SCE's program. Further, this report is not intended to propose disallowances of approved SmartConnect costs. However, data thus far does reveal trends and potential hurdles to achieving an overall net benefit for customers. Based on the analysis in the case study, DRA offers recommendations to regulators, policymakers, and utilities on ways to overcome those hurdles.

Key Findings presented in Section V of this report include:

- According to SCE's AMI business case, the total cost to customers will be greater than $5 billion, rather than the $1.6 billion cost explicitly approved by the CPUC, which only included nominal deployment costs;
- Many forecasted benefits have been delayed or reduced, which erases the projected margin of net benefits as calculated in SCE's business case;
- SmartConnect-related costs not anticipated in SCE's original business case have already been approved by the CPUC in other proceedings, beyond the over $5 billion cost referenced above. In many cases, these costs were approved without a showing of incremental benefits, and DRA anticipates that more will be requested;
- SmartConnect features such as remote disconnect and SmartConnect-enabled time-varying rates have a high potential for adverse impacts for low-income and other "at-risk" customers; and
- Ascertaining SmartConnect net benefits is hampered by a complicated cost recovery process.

The report concludes with specific recommendations to assist the CPUC with ongoing review of AMI-related proposals by the utilities.

A detailed discussion of the recommendations is in Section VI. They include:

1. Track AMI benefits and cost impacts throughout the life of the investment;
2. Require that any request for AMI-related incremental cost recovery includes a showing of increased cost-effectiveness;
3. Ensure that realization of customer benefits are synchronized with recovery of costs;
4. Condition approval of Demand-side Management expenditures on corresponding adjustments to supply-side procurement needs;
5. Create an environment that fosters the development of new benefits from the sunk cost of AMI; and
6. Ensure the needs of low-income and other “at-risk” customers are considered in program development and implementation.

Introduction and Overview

Advanced Metering Infrastructure (AMI) - also known as "smart meters" - is a metering and information technology (IT) system. "Smart meters"[3] are the main, but by no means the only, component of an AMI system. AMI is intended to provide benefits to customers and service providers by automating meter reading, optimizing utility resources, and reducing electricity demand via customer response to more detailed energy usage information.

This report provides the results of an extensive analysis of Southern California Edison's (SCE) AMI system, which is known as "SmartConnect."[4] SCE's AMI deployment was selected for analysis with the intention that lessons learned might apply to the other California utilities deploying AMI. SCE's system was selected initially for this analysis because:

- It was perceived as a "simple case" with only electric smart meters;
- SCE benefited from lessons learned by being the last of the three largest California electric utilities to deploy an electric AMI system;
- SCE's AMI deployment was not complicated by a meter upgrade proceeding, as was Pacific Gas and Electric Company's (PG&E) AMI deployment; and
- SCE has a pending General Rate Case (GRC), in which it is requesting recovery of AMI-related costs.

[3] "Smart meter" has become a generic term for AMI.

[4] SmartConnect™ is the trademarked term for SCE's smart metering system. For ease of reading, we do not include the superscript "TM" in this report.

It is also important to note that, so far, SCE's requests for AMI-related funding have been lower than such requests made by PG&E and San Diego Gas & Electric Company (SDG&E).

The objectives of this report are to:

1. Determine how the actual cost-effectiveness of SCE's SmartConnect system compares to the forecasted costs and benefits of the original business case; and
2. Alert regulators to the risks and complications involved in actually realizing the benefits of AMI systems, especially now that the three large investor owned utilities (IOUs) have begun requesting AMI-related funding beyond that requested and approved in their original business cases.

This report does not provide a definitive answer to the simple question "Does SCE's SmartConnect Program provide a net benefit to customers?" Nor can it since deployment is not yet complete, and the original cost/benefit analysis extends through 2032. Instead, this report provides specific examples of how SmartConnect-related costs are being requested and/or how benefits are being realized in SCE regulatory filings, including Energy Resource Recovery Account (ERRA)[5] applications, Phases 1 and 2 of GRCs,[6] Demand Response (DR) applications, Smart Grid proceedings, and the Long Term Procurement Planning (LTPP)

[5] ERRA is discussed in Section III as well as Appendix 3.

[6] For California IOUs, general rate cases (GRCs) are filed generally every three years and are typically divided into two different proceedings, or "phases." In Phase 1, the CPUC determines the revenue requirement that utilities will be authorized to recover through rates. In Phase 2, the CPUC determines how to allocate the total revenue requirement among the different customer classes, as well as rate design for specific customer classes. Separately, in the intervening years between GRCs, the utilities may file applications to propose new or modified tariffs – this interim process is referred to as the Rate Design Window (RDW).

proceeding. Cost recovery requests in these proceedings were compared to the original SmartConnect forecasts. DRA provides findings regarding AMI cost-effectiveness and recommendations aimed at realizing the projected customer benefits through reduced rates.

The exercise of performing a comprehensive analysis of AMI cost-effectiveness resulted in many lessons learned and highlights areas for further consideration by the CPUC, and other relevant regulatory bodies, to actualize the potential of AMI. DRA intends this report to aid CPUC decision-makers in ensuring cost-effective AMI systems, as well as CPUC staff who will address AMI-related funding requests in future proceedings over the next two decades and beyond.

A glossary, including acronyms and key AMI terminology, is provided in Appendix 1.

II. Background on AMI and SCE's SmartConnect

In California, the CPUC established requirements for AMI systems in response to the electricity crisis of 2000-2001, which was a period of highly volatile wholesale electricity prices and rotating outages resulting from partial deregulation of the electricity market and unchecked market manipulation. The CPUC issued a Ruling ordering California's large IOUs (Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company) to file preliminary AMI deployment analyses, followed by applications containing AMI deployment strategies.[7] Thus, the IOUs began to file applications for deployment of AMI beginning in 2005. PG&E and SDG&E both filed their applications in March 2005.[8]

SCE was the last electric IOU to file an AMI application.[9] At the time that PG&E and SDG&E submitted their applications, SCE's business case analysis, including multiple scenarios, showed that AMI deployment was not a cost-effective endeavor. Two of its scenario analyses showed a positive Present Value Revenue Requirement (PVRR),[10] largely due to the added Demand Response from large customers[11] that already had interval meters.[12] SCE stated that

---

[7] "Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure," R.02-06-001, July 21, 2004, pp. 2 and 4 (mimeo). *See* Attachment A and Appendix A.

[8] "Application of San Diego Gas & Electric (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design," A.05-03-015; "Application of Pacific Gas and Electric Company for Recovery of Pre-Deployment Costs of the Advanced Metering Infrastructure (AMI) Project," A.05-03-016.

[9] SCE filed "Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Activities and Cost Recovery Mechanism," A.07-07-026 on July 31, 2007. Southern California Gas Company filed its AMI application, A.08-09-023 in September 2008.

[10] PVRR is a single calculated value that sums the time-discounted cost/benefit cash flows of SmartConnect (in terms of revenue requirements) for each year of the program.

[11] Large customers are defined as having maximum demand >200 kW.

"the technology envisioned by the Ruling is unproven and not commercially available at this time."[13]

Between 2005 and 2007, SCE requested funds to study and test AMI technology, and the CPUC approved $57.2 million for this purpose. Based on its preliminary findings, SCE filed an application in July 2007 (referred to in this report as the "SmartConnect Application") seeking authorization to spend $1.634 billion to deploy a specific AMI system it called SmartConnect. SCE initially estimated that this investment would result in $109 million in net benefits (PVRR) over the estimated 20-year project life. This estimate increased to $116 million in net benefits (PVRR) through a set of errata testimony and workpapers, submitted in December 2007. SCE's business case continued to evolve through several iterations. SCE and DRA eventually reached a Settlement Agreement, which they petitioned the CPUC to adopt.[14] In late 2008, the CPUC adopted the SCE – DRA Settlement Agreement in Decision (D.)08-09-039 (referred to in this report as the "SmartConnect Decision"), by which the parties estimated a final quantifiable net benefit of $9.2 million (PVRR). The settlement also included $295 million

---

[12] Following the California electricity crisis, the state legislature took immediate action to enable large customers (i.e., customers with maximum demand of >200 kW) to reduce peak load by authorizing $35 million from the State General Fund to the California Energy Commission (CEC) for meters that could measure energy usage in time intervals of one hour or less. Interval meters can store data for a defined time interval and contain electronic components enabling them to be read remotely by the utility and then to communicate the collected energy usage data to a utility's billing system. They are often considered a precursor to AMI, but include fewer capabilities. *See* CEC Report to the Legislature on Assembly Bill 29X, *Real Time Metering Program* (June 2002), pp. 1 and 3 (mimeo). *See* http://www.energy.ca.gov/reports/2002-06-27_400-02-004F.PDF, accessed April 6, 2011.

[13] "Southern California Edison Company's (U 338-E) Revised Preliminary Analysis of Advanced Metering Infrastructure Business Case," R.02-06-001, January 12, 2005, p. 17 (mimeo).

[14] In addition to its motion for adoption of the Settlement Agreement, SCE filed jointly with the Utility Reform Network (TURN) a motion for adoption of stipulations, which are contained within the Settlement Agreement.

(PVRR) in "societal" costs and benefits, though these societal costs and benefits were not included in SCE's final business case for determining cost-effectiveness.[15] In the SmartConnect Decision, the CPUC authorized SCE to spend up to $1.634 billion (nominal) in AMI deployment costs, over a deployment period extending through 2012.[16]

The SmartConnect Decision explicitly authorized a deployment period budget of $1.634 billion and, by finding the SmartConnect program cost-effective over its entire lifecycle, implicitly adopted forecasted post-deployment costs of $1.582 billion and lifetime benefits of $7.4 billion (nominal).[17]

One complexity of analyzing AMI business cases comes from the fact that, on a nominal basis, costs are highly "front loaded" and benefits are "back loaded." In other words, the majority of the estimated costs will be incurred early in the program (i.e., during deployment), while greater benefits were estimated to occur during the later years of the business case. This is shown in the following table.

[15] The adopted settlement included $352 million (PVRR) in societal benefits associated with reduced energy theft detection and increased meter accuracy, as well as $57 million (PVRR) in societal costs associated with higher energy usage.

[16] Contingency costs of approximately $130.1 million were implicitly adopted and are included in the final authorized amount of $1.63 billion. The settlement generally shielded SCE shareholders from potential cost overruns by enabling SCE to record $100 million more than the authorized amount before the program is subject to an after-the-fact reasonableness review. Ten percent (10%) of this additional amount would be borne by shareholders.

[17] D.08-09-039, Findings of Fact 2, 4, 6, 9, and 10.

Table 1: Nominal Costs and Benefits of SmartConnect Program

($ millions)

	Deployment 2007-2012	Post-Deployment 2013 - 2032	Total
Benefits	$437.6	$6,999.7	$7,437.3
Costs	$1,633.5[18]	$1,582.1	$3,215.6
Net Benefits	-$1,1495.9	$5,417.6	$4,221.7

The table shows $4.2 *billion* in net benefits based on a comparison of nominal dollars. In contrast, as stated above, SmartConnect was adopted based on an estimate of $9.2 *million* in net benefits on a PVRR basis owing to the time-discounted value of money.[19] In SCE's PVRR analysis, all costs and benefits were converted to "revenue requirements" and discounted to 2007 as the present value year.

SCE began mass deployment of SmartConnect in September 2009 and, according to a recent SCE quarterly Technical Advisory Panel (TAP) report, it had completed approximately 78% of projected installations as of January 31, 2012. SCE reports that all expenditures recorded to

[18] Note that the deployment cost adopted in the SCE business case is $47.4 million greater than the $1.634 billion authorized for cost recovery by D.08-09-039. The difference includes $45.2 million of pre-deployment costs and $2.2 million of Phase III power procurement costs, which the settling parties used to calculate the final net benefit of the project but were not authorized for recovery in D.08-09-039.

[19] It is important to note that SCE used a discount rate of 10%, which was significantly higher than SDG&E's and PG&E's discount rates of 8.23% and 7.6%, respectively (see D.07-04-043, p.25 (mimeo) and D.06-07-027, p.49 (mimeo)). The effect of SCE's higher discount rate was to reduce the net benefit of SmartConnect in present value terms. Regardless of the discount rate used, the benefits forecasted in the SCE business case still must be reflected as rate reductions, or decreased rate increases, in order to ensure AMI is cost-effective overall.

the Edison SmartConnect Balancing Account (ESCBA)[20] are within budget, and it anticipates completing mass deployment by the end of 2012 with $105 million of the authorized $130.1 million contingency funding remaining as of January 31, 2012.[21] However, it should be noted that incremental funding requests are being made that are not recorded to the ESCBA, as discussed further below.

Appendix 2 contains a more detailed background.

[20] A balancing account is an account established by a utility to record, for recovery through rates, certain authorized amounts and to ensure that the revenue collected is neither less than nor more than those amounts.

[21] All data from the TAP quarterly report.

III. Overview of SmartConnect Cost Recovery Process and Realization of Benefits

Utility expenditures for programs, equipment, plant, and expenses are authorized in CPUC decisions, but authorization does not directly result in rates increasing or decreasing. Additional mechanisms are used to ensure the utility collects these authorized costs through customer bills. The SmartConnect Decision explicitly provides for recovery of deployment costs and a limited portion of the estimated benefits. Post-deployment program costs and a vast majority of program benefits will impact rates through a wide range of routine CPUC cost recovery processes. Ultimately, customer rates are directly changed through a CPUC-approved utility *advice letter*, which modifies *rate tariff sheets*. The following is a brief summary of how SmartConnect deployment will impact customer rates (additional details are provided in Appendix 3).

SCE cost recovery for AMI deployment costs from 2008 through 2012 can be summarized as follows:[22]

- The forecasted SmartConnect deployment revenue requirement is added to customer rates *before* expenses are incurred;
- SmartConnect costs and some benefits are recorded in the ESCBA as they are incurred or realized; and
- Rates are subsequently adjusted for any differences between forecasted and actual revenue requirements.

[22] Recovery of AMI pre-deployment costs of $12 million are not addressed here.

In practice, this is a complicated process that involves multiple balancing accounts and a detailed understanding of the multifaceted Energy Resources Recovery Account (ERRA) proceedings, where balances in these accounts are reviewed. Going forward, the process described above will be modified in two ways. First, beginning in August 2011, SCE's SmartConnect costs will not be recovered through the ERRA proceedings, but rather through an advice letter filing.[23] DRA requested this change because review of advice letter filings will allow greater scrutiny of SmartConnect costs that are eclipsed by the larger fuel and power procurement costs reviewed in the ERRA proceedings.[24] Second, in SCE's pending 2012 GRC application (A.10-11-015), SCE requests authority to keep ESCBA open, with certain limitations, through 2014.[25]

ESCBA was approved to permit recovery of the $1.634 billion of deployment period costs, and $151.5 million in deployment period benefits, as discussed in Finding 1 in Section V below. The only deployment period benefits that are captured in the ESCBA are those associated with meter reading labor cost reductions. Thus, the following costs and benefits are not recovered through ESCBA and must be recovered through alternative means:

1. Additional deployment period benefits, including all capital benefits;
2. "Avoided cost" benefits due to Demand Response programs;

---

[23] "Decision Approving a Consolidated Revenue Requirement Increase of $403.8 Million, But a Rate Level Increase of $183.4 Million," D.11-04-006 in A.10-08-001, April 14, 2011, p. 10 (mimeo), Finding of Fact 9. *Also see* discussion at p. 7.

[24] Ibid.

[25] "Application of Southern California Edison Company (U 338-E) for Authority to, Among Other Things, Increase its Authorized Revenues for Electric Service in 2012, and to Reflect That Increase in Rates," A.10-11-015, 2012 General Rate Case – Customer Service Volume 1 – Policy, November 23, 2010, p. 30 (mimeo).

3. All post-deployment period costs and benefits; and
4. Costs and benefits that are, or will be, incremental to the SmartConnect Decision.

In addition to the general summary of these cost recovery mechanisms in Appendix 3, Section V discusses how these costs and benefits are actually being realized to date.

The benefits defined in the SmartConnect business case should be realized as a rate reduction, or reduced rate increase, which applies to all customers. In addition, individual customers can realize benefits through reduced electricity bills if they use feedback from their SmartConnect meter to reduce their consumption, or to shift their usage to times when it is less expensive when they are on a time-varying rate tariff. The $295 million of societal benefits included in the SmartConnect Settlement relate to increased meter accuracy and reduced theft, but neither the settlement nor the SmartConnect Decision specify how these benefits could be realized.

IV. DRA Analysis Methodology

DRA's review of the SmartConnect program included four major analytical steps:

1. Review and summarize pertinent sections of SCE's AMI business case submitted in Application (A.)07-07-026 ("SmartConnect Application");[26]
2. Analyze SCE's recorded AMI costs and benefits and pending AMI-related cost recovery requests;
3. Compare steps 1 and 2 above; and
4. Investigate and explain the cause of any deviations found in step 3 above.

Although SCE updated the SmartConnect business case and workpapers through several iterations of testimony, SCE never updated its workpapers to reflect the final settlement adopted by the SmartConnect Decision.[27] In order to review and summarize SCE's adopted AMI business case, DRA developed its own workpaper which quantifies the final set of costs and benefits adopted in the SmartConnect Decision through the following:

[26] SCE's AMI business case for SmartConnect is a detailed analysis of whether the proposed program will provide net benefits, on a present value basis. *See* "Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism," A.05-03-026, March 30, 2005; "Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Pre-Deployment Activities and Cost Recovery Mechanism," A.06-12-026, December 21, 2006; and "Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Activities and Cost Recovery Mechanism," A.07-07-026, July 31, 2007. *Also see* http://www.sce.com/CustomerService/smartconnect/industry-resource-center/regulatory-filings.htm, accessed June 28, 2011.

[27] In at least one data request response, SCE stated that it did not update its workpapers to reflect the final settlement adopted by the SmartConnect Decision. *See* SCE response to DRA data request (DRASmtCnt-SCE-KAR-002 question 2), received April 29, 2011.

- Adjusting for the terms of the Settlement Agreement; [28]
- Combining and reformatting SCE's original workpapers into a single spreadsheet which shows the nominal value of each cost and benefit for each year, (2007 – 2032);
- Categorizing costs and benefits as capital or Operations & Maintenance (O&M); and
- Categorizing costs and benefits as either operational or demand response related.

The resulting workpaper was cross-checked against the Settlement Agreement and original workpapers to ensure it was accurate within $0.05 million.[29] The final DRA workpaper allows for easy review, sorting, and charting of summary data, or annual data for any year, for each cost and benefit. Table 2 provides a summary of DRA's workpaper.

Table 2: SmartConnect Costs and Benefits

($ millions, nominal)[30]

		Deployment Costs	Post-Deployment Costs	Deployment Benefit	Post-Deployment Benefit
Operations					
	Capital	$ 1,187.9	$ 410.2	$ 86.5	$ 341.6
	O&M	$ 258.3	$ 823.1	$ 170.7	$ 3,704.4
	Total	$ 1,446.2	$ 1,233.3	$ 257.1	$ 4,046.0
Demand Response					
	Capital	$ 38.8	$ 16.3	$ 70.3	$ 161.8
	O&M	$ 148.5	$ 332.6	$ 110.2	$ 2,792.0
	Total	$ 87.3	$ 348.8	$ 180.5	$ 2,953.8
Total (Operations & Demand Response)					
	Capital	$ 1,226.7	$ 426.4	$ 156.8	$ 503.4
	O&M	$ 406.8	$ 1,155.7	$ 280.8	$ 6,496.3
	Total	**$ 1,633.5**	**$ 1,582.1**	**$ 437.6**	**$ 6,999.7**
Total		$ 3,215.6		$ 7,437.3	

[28] D.08-09-039, Appendix A.

[29] Figures in the adopted settlement were rounded to the nearest $0.1 million.

[30] This is based on DRA workpapers that estimate the adopted costs and benefits of the SmartConnect decision; original data is from SCE's workpapers in the SmartConnect Application.

Analysis of the recorded and requested costs required extensive discovery with SCE. While SCE was cooperative and timely in providing responses, discovery and analysis was complicated by the fact that the cost categories in the AMI business case were not perfectly aligned with those used in subsequent proceedings. Note that DRA's analysis is based on nominal values for each year of the business case, since there was insufficient time or resources to operate SCE's revenue requirement model.[31] Small, but noteworthy, errors may be encountered where costs and benefits calculated in different years are compared.

Comparing actual SCE cost requests with the SmartConnect business case requires clear definitions of the following terms:

- Deployment costs/benefits;
- Post-deployment costs/benefits;
- Incremental costs/benefits;
- Capital costs/benefits;
- O&M costs/benefits;
- Operational costs/benefits; and
- Demand Response-related costs/benefits.

Each of these terms is defined in Appendix 1.

[31] In its workpapers, SCE provided annual itemized cost data in nominal terms and separately provided a "revenue requirement model" by which (nominal) cost categories could be translated into revenue requirements. While it is more accurate to analyze revenue requirements, as these are the real costs to ratepayers, DRA did not have sufficient information to be able to calculate revenue requirements for each individual cost/benefit item.

V. Findings

1. Without Effective Regulatory Oversight of AMI Costs and Benefits, it is Unlikely that Projected SmartConnect Benefits will be Fully Realized.

It is challenging to monitor AMI-related costs, as discussed further below. It is even more challenging, however, to ensure estimated benefits are realized, since in most cases benefits are actually a *reduction in costs*, compared to a scenario without SmartConnect. Tracking benefits requires analysts to be knowledgeable of the more than 130 different costs and 50 projected benefits; this knowledge needs to be maintained and applied through 2032, unless SmartConnect is replaced before this time.

As noted previously, the SmartConnect Decision established a recovery mechanism for only a limited set of deployment benefits. Specifically, $151.5 million in operational O&M benefits[32] during the deployment period, which amounts to less than 2% of the total benefits estimated in the business case, were expected to be recovered through the Edison SmartConnect Balancing Account (ESCBA).[33] However, due to delays in program deployment, it appears that the actual benefit realized via this mechanism will be closer to $100 million.[34] The

[32] This amount is different from the amount recorded in Table 2. The discrepancy is due to pensions, post-retirement benefits other than pensions, and results sharing that are not recorded in ESCBA.

[33] D.08-09-039, Appendix A, p. 10. These benefits are operational (as opposed to DR) O&M benefits during the deployment period, net of pensions, benefits, and profit sharing.

[34] D.08-09-039 assumed the benefit of $151.5 million would be recovered over 106 million "meter months" and adopted a recovery rate of $1.42 per meter for each month the meter was installed (a meter month). The term "meter months" refers to the total number of months each meter is deployed in the deployment period. This value was estimated by SCE and was

remaining amount of nearly $50 million, and all other estimated SmartConnect benefits, can only be realized through cost reductions in other proceedings. DRA's analysis indicates that achieving cost reductions is hampered by poorly defined cost recovery mechanisms, lumping SmartConnect costs within the ERRA proceeding, overlapping funding requests from AMI-related proceedings, and the lack of accounting for the contribution of demand reduction programs (Energy Efficiency and Demand Response) in assessing the need for new utility power procurement. Some examples are discussed below.

Deployment Period Capital Benefits are Not Fully Reflected in Rate Reductions

First, SmartConnect benefits other than the limited deployment benefits above should be realized as a reduction, or at least a reduced increase, in cost requests in GRCs, ERRA proceedings, specific Demand-side Management (DSM) programs, and the CPUC energy and capacity procurement processes. However, this is not happening to the full extent forecasted by SCE. For example, recovery of $86.5 million in deployment period operational capital benefits was not well defined in the SmartConnect Decision.[35] The largest category within

---

intended to capture all of the operational O&M benefits resulting from SmartConnect monthly during the deployment period, as meters are activated. In response to a DRA data request, SCE provided an updated estimate that the number of meter months at the end of 2012 will be 72.0 million. Using this revised estimate and the adopted recovery rate of $1.42 per meter month results in a total benefit in rates of $102.2 million, rather than $151.5 million. *See* SCE response dated May 26, 2011 to DRA data request DRA-SCE 270-tcr, question 4b, in the 2012 GRC, A.10-11-015.

[35] Capital benefits totaled $86.5 million, but the SmartConnect Decision only addresses realization of capital benefits during 2009-2011, accounting for just $15 million of the capital benefits. Realization of capital benefits after 2011 was not addressed at all. *See* "Decision Adopting Settlement on Southern California Edison Company Advanced Metering Infrastructure Deployment," D.08-09-039, in A.07-07-026, September 18, 2008, p. 12 of Appendix A (mimeo) and p. C-3 of Attachment C to Appendix A (mimeo). *Also see* SCE Testimony in A.07-07-026 dated July 31, 2007, SCE-5, pp.8-9.

those operational capital benefits was related to the avoided cost of electromechanical meters, estimated at $46.5 million in the SmartConnect business case for the deployment period. DRA was able to determine that those benefits for 2009-2011 were to be reflected in rates through annual advice letter filings, pursuant to SCE's Post-Test Year Ratemaking Mechanism.[36] In ERRA testimony, SCE described the avoided cost of legacy electromechanical meters for 2010, whereby SCE credited $1.6 million for the "2010 capital-related revenue requirement benefit to the BRRBA."[37] Further, in its 2012 GRC testimony, SCE states that "meter capital benefits will recognize reductions in meter capital expenditures of $1.6 million in 2010 and $5.1 million in 2011. Consistent with this approach, $8.5 million in meter capital benefits will be included in the GRC capital meter forecast in 2012."[38] The ERRA testimony does not note any benefits from 2009, and the GRC testimony and supporting workpapers do not describe how the benefits for 2011 were determined, or how they have been, or will be, realized as rate reductions. Additionally, the amounts noted in ERRA and GRC testimony are lower than the amount estimated in the SmartConnect business case. Recovery of 2012 capital benefits was not discussed in the SmartConnect Decision, but this should logically occur in the 2012 GRC.

---

[36] In the ERRA forecast proceeding, the credit and debit entries in the Authorized Distribution Base Revenue Requirement (ADBRR) are evaluated. Prior to the 2012 GRC any cost reductions associated with avoiding the purchase of legacy meters would have been booked as a credit to the ADBRR, the resulting balance of which is reflected in Post-Test Year Ratemaking advice letter filings and flows through the ERRA forecast proceeding. DRA did not find evidence of that being done. *See* SCE Testimony in A.07-07-026 dated July 31, 2007, SCE-5, pp.8-9. SCE footnote 16 on page 8 of this testimony further states "SCE currently expects that all of the Phase III costs and benefits, as adopted in a decision in this proceeding, will be incorporated into its 2012 GRC forecast; and therefore a separate ADBRR reduction for 2012 Phase III capital benefits may not be necessary."

[37] *See* SCE testimony in A.11-04-001, Chapters IX-XVI, Review of Operations 2010, public version, p. 135. The purpose of the Base Revenue Requirement Balancing Account (BRRBA) is to record: 1) the difference between SCE's authorized distribution and generation base revenue requirements and recorded revenues from authorized distribution and generation rates; and 2) record other authorized and recorded costs authorized by the Commission.

[38] *See* SCE testimony in A.10-011-015 dated November 2010, SCE-4, volume 4, p.11.

SCE's 2012 GRC testimony indicates that they are claiming a meter benefit of $8.5 million for 2012, but in the same table, SCE indicates that the total routine metering capital cost is $20.5 million, leaving $12 million of potential benefits unaccounted for.[39] After a detailed analysis, the full extent to which rates have been reduced for deployment period benefits is not apparent. However, to the extent deployment period capital benefits are reflected in rates, those benefits appear to be much lower than forecasted in the SmartConnect business case. This analysis highlights the challenges in accurately tracking benefits as rate reductions through multiple proceedings.

Meter Reading Benefits are Not Fully Actualized

A second example of cost reductions not being achieved relates to the realization of post-deployment benefits in GRC applications and is illustrated using the single largest estimated benefit class, reduced meter reading costs.[40] SCE's TY 2012 GRC requests metering costs and cost reductions (benefits) in the discussion of Federal Energy Regulatory Commission (FERC) account 902.[41] SCE states that "[FERC] account 902 captures *all* expenses related to reading of customer meters,"[42] and that "approximately 98 percent of field meter reading" will be automated due to SmartConnect.[43] SCE provides an analysis of metering costs that indicates a cost of $12.0 million in 2013, comprised of 2009 recorded costs of $44.3 million

---

[39] *See* SCE Testimony in A.10-11-015, SCE-04, volume 4, p.11.

[40] Nearly $1.5 billion in meter reading benefits were forecast for the post-deployment period, 2013 through 2032.

[41] Electric public utilities & licensees, natural gas pipeline companies, oil pipeline companies, and centralized service companies within FERC jurisdiction are required to maintain their books and records in accordance with the CPUC's Uniform System of Accounts (USofA). The USofA provides basic account descriptions, instructions, and accounting definitions.

[42] A.10-11-015, SCE-4, Volume 2, p.125 (mimeo). Emphasis added.

[43] A.10-11-015, SCE-4, Volume 2, p.1 (mimeo).

reduced by $32.3 million for "SmartConnect" benefits.[44] The 2013 estimated meter reading costs for full SmartConnect deployment are therefore 27.7% of the recorded pre-deployment meter reading costs. However, the SmartConnect business case estimated a benefit of $62.1 million in 2013 for meter reading costs associated with FERC account 902, which is nearly double the $32.3 million benefit suggested in the TY 2012 GRC.[45] Thus, it appears that the requested SmartConnect benefit, which reduces metering costs by only 72.3%, is too small, and the residual 2013 metering costs of $12.3 million is excessive. Stated another way, SCE has requested over $12 million annually for direct labor and non-labor meter reading expenses for 2013 in the TY 2012 GRC.[46] SCE has not documented why it needs over 27% of the pre-SmartConnect meter reading expenses, even after 98% of this function has been automated, and the post-SmartConnect expenses have been shifted to other FERC accounts.[47]

---

[44] A.10-11-015, SCE-4, Volume 2, Figure IV-10, p.130 (mimeo).

[45] This comparison is complicated by the fact that estimated SmartConnect benefits are based on a labor rate which includes benefits, while the GRC benefits mentioned above does not. However, in the TY 2012 GRC, SCE only provided analysis of 2013, and hence a discussion of post-deployment benefits, in Customer Service Organization testimony (exhibit SCE-4). Exhibit SCE-6, which covers employee benefits, does not discuss 2013 cost or benefits, and therefore the forecasted benefit of reduced employee benefits was not requested in this GRC

[46] A decision in SCE's 2012 GRC is currently pending as of October 31, 2011. The CPUC *may* order SCE to update its 2013 attrition filing to include updated meter reading costs, which may be higher or lower than the estimates included in the current application. However, that is unlikely unless a party specifically raises the issue. At the time this paper was drafted, DRA was not aware of any recommendations that SCE be required to update meter reading costs in its 2013 attrition filing. This example demonstrates the need for explicitly tracking costs and benefits of AMI, as ensuring the expected benefits of one specific technology can easily be lost in the enormity of a GRC.

[47] For example, SmartConnect operations center costs are requested in FERC account 902.3. *See* A.10-11-015, SCE-4, Volume 2, p.131 (mimeo).

Avoided Capacity Benefits May Not be Achieved

Another example of cost reductions not being achieved relates to benefits attributed to the Peak Time Rebates (PTR)[48], Critical Peak Pricing (CPP)[49], and Time-of-Use (TOU)[50] rates enabled by SmartConnect deployment. The following table shows that the estimated benefits from these three programs are due to avoided energy and capacity purchases and that they total over $[redacted] in the post-deployment period.[51]

Table 3: Adopted Post-Deployment (2013-2032) Benefits Related to Demand Response

($ in millions)*[52]

Category	PCT	PTR	TOU	CPP	IHD	All/shared	Total
Avoided energy & capacity purchases	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
Conservation effect					[redacted]		[redacted]
TDBU Deferred Capital	[redacted]					[redacted]	[redacted]
Measurement & evaluation						[redacted]	[redacted]
Program benefit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

*Errors due to rounding

From a customer perspective, "avoided capacity" means rates that reflect the avoidance or deferral of new power procurement resulting from successful demand-side resources, such as energy efficiency (EE), Demand Response (DR), distributed generation (DG), and time-varying rate programs. However, new power procurement is actually avoided/deferred if, and only if,

[48] Peak Time Rebates (PTR) are rebates that can be offered to customers who lower their energy usage on peak event days.

[49] Critical Peak Pricing (CPP) is a time-varying rate whereby electricity prices rise significantly on certain days, established one day prior to the calling of high-demand days

[50] Time-of-Use (TOU) is a time-varying rate whereby pre-established rates vary based on the time at which electricity is used.

[51] Deployment period benefits for PTR, TOU, and CPP add $[redacted], $[redacted], and $[redacted] respectively to these figures.

[52] IHD refers to in-home displays. TBDU refers to Transmission and Distribution Unit.

utilities include the forecasted demand-side resources (i.e., MW savings) into their procurement plans. In its current Long Term Procurement Plan (LTPP) proposal, SCE argues that 653 MW of "AMI-enabled DR" included in the CPUC's Standardized Planning Assumptions should not be included in its forecast of available DR resources. SCE stated this capacity reduction would not be achieved "because of the considerable uncertainties that surround AMI-enabled DR at this time." SCE's Preferred Analysis excludes capacity from AMI-enabled DR programs, such as the Programmable Communicating Thermostat (PCT), Residential TOU, medium commercial and industrial (C&I) CPP, and medium C&I TOU programs, because "it is not necessary to use very aggressive DR assumptions in establishing SCE's maximum procurement limits."[53] This last sentence is in striking contrast to previous SCE statements that the assumptions used to estimate DR benefits in the Smart Connect business case were "reasonable" and "conservative."[54]

If the CPUC accepts SCE's preferred DR forecast, then the benefits associated with avoided capacity purchases, as adopted in the SmartConnect business case, will not be realized and will further reduce the cost-effectiveness of SCE's SmartConnect investment. Over the ten year period covered by SCE's LTPP proposal, this would amount to approximately $[redacted], or [redacted]%, in reduced benefits.[55]

---

[53] "Rebuttal Testimony of Southern California Edison Company to Intervenor Testimony on AB 57 Bundled Procurement Plan," R.10-05-006, Exhibit SCE-10, pp. 28-29 (mimeo).

[54] See for instance SCE-4 (errata) at p. B-14, lines 4-8 regarding load impact estimates from CPP and TOU for C&I customers. *Also see* SCE-8 (rebuttal) pp. 2-10 regarding all Demand Response estimates.

[55] This estimate is based on the avoided cost assumptions used in A.07-07-026.

2. In Order to Realize the Full Lifecycle Benefits of the Adopted Business Case, the Full Cost of SmartConnect will be More than Double the $1.6 Billion Approved for Deployment Costs.

Though not made clear in the SmartConnect Decision, the SmartConnect business case implicitly included post-deployment costs of $1.582 billion[56] in addition to the explicitly approved deployment costs of $1.634 billion. SCE's deployment costs received much attention in the SmartConnect Decision, but additional attention will need to be paid to the post-deployment cost requests as the deployment period comes to a close. As discussed in greater detail in Finding 4, it is practically impossible to track most post-deployment costs given the cost recovery processes adopted for SCE.

The CPUC should carefully scrutinize the classification of costs as capital versus Operations and Maintenance (O&M). A major impact on program cost is the rate of return SCE earns for SmartConnect costs classified as capital expenditures, which leads to revenue requirements and rate increases much larger than the nominal value of those costs or expenses. As shown in Table 2 above, capital costs account for approximately 75% of deployment costs and 37% of post-deployment costs, or $1.65 billion total capital costs. Given that the majority of SmartConnect costs are capital costs, it is not surprising that prior to the SmartConnect Settlement, SCE estimated a total revenue requirement of more than $5 billion (nominal) over

[56] Implicitly approved costs include such things as ongoing demand response costs, telecommunications costs necessary to maintain and update the smart meter communications system, meter costs for new customers or replacements due to failures, and support systems such as data management systems, bill verification, and quality assurance checks.

the life of the project.[57] Classification of costs as capital or expense is governed by generally accepted accounting principles (GAAP) and federal accounting standards.

Other likely costs beyond the SmartConnect business case include incremental costs that were largely unforeseen at the time of the AMI proceedings. Some incremental AMI-related costs have already been requested, as discussed further in Finding 3, while others have not yet been requested but are anticipated by DRA, based on CPUC decisions in various proceedings. For example, a small percentage of customers throughout California requested to forgo smart meter installation and retain their current electromechanical meters, and the CPUC recently adopted an AMI "opt-out" option for PG&E customers.[58] If SCE decides, or is ordered, to provide an alternative metering system in parallel with SmartConnect, incremental costs will be incurred and some may be charged to customers at-large.[59]

Incremental AMI-related costs could also be incurred in a multitude of programs that the CPUC oversees in support of California's energy policy goals. While such incremental AMI-related costs may be anticipated, and not necessarily objectionable, all of the incremental AMI-related

[57] SCE-3 (errata), Table V-18 / p. 52 (mimeo). This table does not reflect the deployment and post-deployment costs in the Settlement Agreement, which were approximately $50 million higher on a nominal basis than in the errata workpapers.

[58] *See* "Decision Modifying Pacific Gas and Electric Company's SmartMeter Program to Include an Opt-Out Option," D.12-02-014, February 1, 2012, in A.11-03-014. *Also see* "Application of Pacific Gas and Electric Company for Approval of Modifications to its SmartMeter™ Program and Increased Revenue Requirements to Recover the Costs of the Modifications," A.11-03-014; "Application of Utility Consumers' Action Network for Modification of Decision 07-04-043 so as to Not Force Residential Customers to Use Smart Meters," A.11-03-015; and "Application of the County of Santa Barbara, the Consumers Power Alliance, et al for Modification of D.08-09-039 and a Commission Order Requiring Southern California Edison Company (U338E) to File an Application for Approval of a Smart Meter Opt-Out Plan," A.11-07-020.

[59] The incremental costs could be funded by ratepayers generally, customers who opt out, or SCE shareholders, at the discretion of the CPUC.

costs in each program area discussed below should have incremental benefits associated with them. These benefits should be compared to the benefits forecasted in the AMI business cases to ensure the same benefits are not "recycled" or otherwise erroneously used to justify new cost requests.

Smart Grid

A large component of the currently envisioned Smart Grid involves using smart meters to monitor conditions in the distribution system and to help customers control their energy usage and bills through AMI-enabled in-home devices. The CPUC recently directed the three large IOUs to make AMI data available to customers online, provide third party access to AMI data with customer authorization, and develop Home Area Network (HAN)[60] implementation plans with an initial phased rollout of 5,000 HAN devices.[61] Each of these mandates is AMI-enabled and will have incremental costs attached, though the costs are not known at this time.

Additionally, in July 2011 the three large IOUs filed Smart Grid deployment plans in conformance with CPUC directives, which called for such plans to include a vision statement for a Smart Grid, planned components of a Smart Grid, and estimated costs and benefits of those components. Once deployment plans are adopted, they may be used as just one part of the justification for future funding requests. As AMI-enabled programs and technologies are

---

[60] HAN is a communication network within the home of a residential electricity customer that allows transfer of information between electronic devices, including, but not limited to, in-home displays, computers, smart appliances, energy management devices, direct load control devices, distributed energy resources, and smart meters. HANs can be wired or wireless.

[61] "Decision Adopting Rules to Protect the Privacy and Security of the Electricity Usage Data of the Customers of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company," D.11-07-056 in R.12-08-009, July 28, 2011, pp. 164-166 (mimeo), Ordering Paragraphs 5, 6, and 11.

such a prominent part of Smart Grid, their inclusion in deployment plans may indicate future funding requests that are incremental to the IOUs' adopted AMI business cases.[62]

Alternative Fueled Vehicles

Alternative-Fuel Vehicles (AFVs), specifically Plug-in Electric Vehicles (PEVs), offer many potential benefits beyond decreasing oil dependence, such as offering load management via energy storage capabilities. Many of these added benefits require communication from the vehicle to the electric grid, as well as from the grid to the vehicle, which can leverage previously deployed smart meters. In Rulemaking (R.)09-08-009, the CPUC is currently considering the impacts AFVs may have on the state's electric infrastructure and what actions the CPUC should take.[63] In a 2011 decision, the CPUC made clear that while it did "not conclude that the meter is needed for anything other than measuring electricity usage at this time," it did "confirm the utilities' obligation to ensure that PEV meters are AMI- and HAN-enabled."[64] As discussed in Finding 3 below, SCE has already requested funding for PEV metering expenses, which are incremental to the SmartConnect business case.

---

[62] *See* D.10-06-047.

[63] "Order Instituting Rulemaking to Consider Alternative-Fueled Vehicle Tariffs, Infrastructure and Policies to Support California's Greenhouse Gas Emissions Reductions Goals," R.09-08-009, August 24, 2009, p. 2 (mimeo).

[64] "Phase 2 Decision Establishing Policies to Overcome Barriers to Electric Vehicle Deployment and Complying with Public Utilities Code §740.2," D.11-07-029 in R.09-08-009, July 14, 2011, p. 34 (mimeo).

Energy Efficiency/Integrated Demand-side Management

The SmartConnect business case included both demand (kW) and energy (kWh) reduction benefits, the latter through in-home displays (IHDs) that would interface with the meter in order to show customers their energy use in real time. Energy Efficiency (EE) and Demand Response (DR) are natural complements to each other; indeed many of the IOUs' EE programs achieve both energy (kWh) and demand (kW) savings. Acknowledging this overlap, the CPUC approved funding for Integrated Demand-side Management (IDSM) activities through both EE (D.09-09-047) and DR (D.09-08-027), though it has stated that "future authority and funding for IDSM activities [will] be considered in future energy efficiency proceedings, starting with the energy efficiency applications for 2013-2015."[65] Given this consolidation of IDSM funding requests, it is entirely possible for the utilities to request recovery of both AMI post-deployment costs as well as costs that are incremental to their AMI business cases through their EE applications. Particular costs from the SmartConnect business case that SCE could eventually consolidate into an EE portfolio application include IHD rebates – especially if the CPUC denies SCE's request to extend the Edison SmartConnect Balancing Account (ESCBA) through 2014 – along with web presentment tools such as the Residential Tier Alert, which the CPUC disapproved for SCE's 2009-2011 DR portfolio on the basis that it was more focused on energy conservation rather than demand response.[66] Going forward, there is significant potential to use the HAN technology to communicate with smart meters for EE- and energy conservation-specific activities.

[65] R.07-01-041, Administrative Law Judge's Ruling Providing Guidance for the 2012-2014 Demand Response Applications, August 27, 2010.

[66] SCE subsequently funded Tier Alert costs through the ESCBA.

Distributed Generation

Distributed Generation is generally understood to mean generation with capacity up to 20 MW and interconnected to the distribution system primarily to serve local load. The CPUC administers a variety of Distributed Generation (DG) programs, including the California Solar Initiative (CSI)[67] and the Self-Generation Incentive Program (SGIP).[68] Smart meters will provide more granular energy usage data that can be used to evaluate program performance for these and other Demand-side Management programs and will allow Net Energy Metering (NEM)[69] on a Time-of-Use (TOU) basis. The voltage measurement capabilities of SmartConnect meters could also help evaluate the impact of DG on distribution system performance, particularly as the level of DG penetration increases.[70]

3. SCE has Begun to Request Incremental AMI-related Costs, before Deployment has been Completed.

In Finding 2 above, potential incremental costs are discussed. This finding addresses actual requests SCE has made to date. AMI-related costs fall into one of three categories:

1. Approved deployment costs;

---

[67] CSI provides incentives to customers who install solar energy systems

[68] SGIP provides incentives to support existing, new, and emerging distributed energy resources, including wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells, and advanced energy storage systems.

[69] NEM is a program available to CSI and SGIP customers whereby they can “sell” their excess generation to their utility at the utility’s applicable retail rate

[70] DRA has commented multiple times in DG proceedings that the ratepayer investment in AMI systems should be leveraged to support DG programs and systems, but to date DRA is not aware that SCE or any California utility has requested funds for this purpose.

2. Post-deployment costs quantified in the AMI business case; or
3. Incremental costs related to AMI, either unanticipated in the original business case, or necessary in addition to costs previously approved, to achieve the anticipated benefits.

From a regulatory standpoint, the full cost of an AMI program should include *all three* categories. However, it can be difficult to classify costs if baseline conditions are not known. For example, SCE's business case defines deployment costs primarily based on when they are incurred, rather than for a specific list of deliverables, making it difficult to determine if a post-deployment cost requested in the GRC application should have instead been recovered through ESCBA.[71] In DR applications and the Test Year (TY) 2012 GRC, SCE began to request incremental AMI-enabled costs, even before SmartConnect was 50% deployed. Some incremental AMI-enabled costs can be necessary, but only if we can reasonably expect such costs to produce incremental benefits which improve the overall cost-effectiveness of the SmartConnect program.

In SCE's 2009-2011 DR portfolio (A.08-06-001), D.09-08-027 approved incremental costs of $1.3 million for two pilot projects related to the programmable communicating thermostat (PCT) program approved by the SmartConnect decision, but which SCE had yet to implement to the extent anticipated in their AMI business case. As indicated, the $1.3 million is incremental, which means that it is in addition to adopted costs anticipated for the PCT

[71] SCE's testimony in its SmartConnect Application describes the elements of the SmartConnect system and the functionality it will provide, but the description is spread over multiple exhibits and does not account for changes in the authorized program. DRA reviewed SCE's testimony and the settlement to develop its own list of what should be delivered as part of SmartConnect deployment.

program. D.09-08-027 also included certain other costs (mainly pilot projects, measurement and evaluation, and outreach and education) which are related to SmartConnect to varying degrees. These cost requests were not supported with quantification of incremental benefits, and there is no evidence to date that they will produce incremental benefits.

In the TY 2012 GRC, SCE specifically requested SmartConnect incremental costs for the Customer Service Business Unit in 2013.[72] This includes multiple incremental cost increases, including $1.079 million for nine new employees to test and inspect meters, and cost decreases, such as $1.222 million in reduced marketing costs. These and other associated costs and benefits net to a total cost increase of $1.45 million.[73] This request for an increase in SmartConnect costs was not accompanied with a description of incremental benefits that would be provided. Also, SCE requests the addition of 21 new staff positions to support PEV meter testing,[74] which should include testing compatibility with deployed SmartConnect meters and HAN devices. The SmartConnect business case did not include costs or benefits associated with PEVs, so some of the costs for these new positions are an example of incremental AMI-enabled costs.

[72] SmartConnect incremental costs for 2013 were only provided for CSBU, not for any other business units or organizations in the TY 2012 GRC.

[73] A.10-11-015, exhibit SCE-4, volume 1, Table V-3, p. 26.

[74] A.10-11-015, exhibit SCE-4, volume 2, Table III-5, p. 19.

In its 2012-2014 DR application SCE is requesting $33.4 million for 2012-2014 funding of critical peak pricing (CPP) (<200 kW) [75] and peak-time rebate (PTR) / Save Power Day – approximately $12.6 million more than estimated in the business case. [76] The DR application also includes estimated benefits different than those adopted in the SmartConnect decision: 102 MW more for CPP and 40 MW less for PTR. Those changes represent a 16.9% decrease in cost-effectiveness on a dollars-per-megawatt basis. [77]

While these incremental cost requests are small compared to the adopted SmartConnect deployment costs, they illustrate how the original estimates of cost-effectiveness can be degraded if such cost requests are not accompanied by even larger incremental benefits. It should also be noted that, to date, SCE's requests appear to be lower than both PG&E and SDG&E.[78] One challenge revealed by this analysis is that it can be very difficult to determine how to classify CPUC-approved costs as deployment, post-deployment, or incremental and thus determine how costs should be recovered. Accurate descriptions of baseline conditions

[75] "Southern California Edison Company 2012-2014 Demand Response Program Portfolio," A.11-03-003, Exhibit SCE-1, Vol. 2, pp. 45-49 (mimeo). Although SCE's proposal for CPP in the DR application also includes agricultural and pumping customers, the proportion of these customers to the total is 0.2 percent, so we assume the marginal cost to include these customers is negligible.

[76] Confirmed per SCE's response to a data request (A.11-03-003, DRA-SCE-002), received April 27, 2011.

[77] Rebuttal Workpapers_MW_Calculations, Event Day MW, CPP MW Reduction in 2014 (cell M189); and SCE response to DRA data request (A.11-03-003, DRA-SCE-002, Q. 13). In its data request, DRA did not request C&I-specific load reduction estimates for 2012 and 2013.

[78] For example, PG&E has requested AMI-related funding in A.05-12-002 (2007 GRC, approximately $263 million), A.08-06-003 (2009-11 Demand Response, approximately $54 million), A.09-02-022 (2009 RDW, approximately $123 million), A.09-12-020 (2011 GRC Phase 1, approx. $310 million) and A.10-03-014 (2011 GRC Ph. 2, approximately $52 million), A.09-08-018 (SmartAC, approx. $38 million), and A.10-02-028 (2010 Rate Design Window, approximately $29 million). SDG&E has requested $118 million incremental funding in A.10-07-009 (Dynamic Pricing Application) and over $11 million in A.10-12-005 (2012 GRC Ph. 1). These examples may not include all AMI-related funding requests, as DRA has not performed a comprehensive analysis of PG&E's or SDG&E's post-AMI decision applications.

at the utility and a detailed list of what will be delivered through AMI project funding are required to make such determinations. Recommendations related to this aspect are made in Section VI.

4. The Current Process for Cost Recovery Poses Difficulties in Comparing Actual SmartConnect Revenue Requirement Impacts with SCE's Original Cost Estimates.

AMI affects many facets of utility operations and demand-side programs, which creates challenges in tracking the costs and cost reductions attributable to SmartConnect. As noted in Section III, cost recovery has only been clearly established for deployment period costs (O&M and capital) and a limited set of deployment benefits (O&M). The remaining costs and benefits, roughly half of the nominal costs and a vast majority of forecasted benefits, must be realized through a variety of proceedings including GRCs, Rate Design Window (RDW)[79] proceedings, and potentially through the proceedings discussed in the previous finding. SmartConnect is being deployed in parallel with many other programs designed to reduce energy consumption or modernize the electrical grid. Attribution of costs and benefits to a specific program such as SmartConnect is increasingly difficult as the CPUC moves toward Integrated Demand-side Management (IDSM) and building a Smart Grid.

[79] According to the CPUC's Rate Case Plan, utilities may file proposals to change their rate designs once per year in years between General Rate Cases (GRCs), typically in the 4th calendar quarter. Such proceedings are called Rate Design Window proceedings.

Comparing the deployment costs and benefits in the Edison SmartConnect Balancing Account (ESCBA) with forecasted values is relatively straightforward, but tracking the revenue requirements impacts currently requires delving into a series of arcane elements of the ERRA proceedings. SCE discusses SmartConnect costs in this large and multifaceted proceeding at a very high level. SCE does not, for instance, report on the specific recorded SmartConnect expenses as they correspond with the cost/benefit items in the adopted business case. Only a comprehensive audit of the ESCBA activity would address concerns regarding whether: (1) the recorded costs are consistent with the estimates adopted in the business case, and (2) SCE is recording costs correctly as capital vs. O&M. Such an audit will likely not occur unless the CPUC explicitly orders one.[80]

Outside of ESCBA, SCE has requested cost recovery for different components of the SmartConnect DR programs through different applications. Several types of AMI-related costs - namely for Information Technology (IT), marketing and outreach, and measurement and evaluation - appeared in both SCE's Demand Response (DR) 2012-2014 application as well as its 2012 GRC Phase 1 application. While they may not be duplicative, the fact that this situation arises means that, even after carefully scrutinizing the utility's testimony and in many cases performing extensive discovery, analysts are required to assure that there are no duplicative cost requests. Moreover, most of the costs that did trace back directly to the business case were significantly different from the adopted estimates. In many cases, though

[80] The adopted settlement in PG&E's 2011 GRC Phase 1 included an independent audit, the cost of which "shall be recoverable through the SmartMeter balancing accounts." D.11-05-018 Attachment 1, pp. 1-10 (mimeo). The purpose of the audit was to determine whether costs that should have been recorded in PG&E's smart meter balancing accounts were instead recorded in other accounts.

not all, this was due to changes in key aspects of the adopted programs. For instance, the adopted Peak Time Rebate (PTR) program included an illustrative rebate of \$0.66 per kWh reduction. However, the CPUC did not actually adopt rebate levels until SCE's 2009 GRC Phase 2 proceeding. Through D.09-08-028, the CPUC adopted PTR rebate levels of \$0.75 and \$1.50 for customers with enabling technologies. Such program changes will likely continue over the life of SmartConnect. Analysts should assess such proposed changes carefully to balance achieving the greatest net benefit from AMI-enabled DR programs with minimizing bill impacts and volatility.

Further compounding the complexity in tracking post-deployment costs is the fact that SCE's 2012 GRC application overlaps the authorized operation of the ESCBA in 2012. While SCE prepared a separate Test Year (TY) forecast for the business unit most impacted by SmartConnect to explicitly reflect this overlap, it is nevertheless difficult, if not impossible, to determine from SCE's testimony whether or not it is requesting costs that are duplicative of approved SmartConnect funding in its TY 2012 forecast. For example, a side-by-side exhibit comparing SmartConnect costs forecast to occur in 2012 with all AMI-related costs included in the TY 2012 forecast would have helped the CPUC confirm SCE's statement that it is not requesting double recovery in its 2012 GRC. Moreover, SCE proposed to extend the ESCBA beyond 2012 in order to recover costs for specific deployment activities, and if this proposal is adopted by the CPUC, the period of potential overlap will be extended.

5. Implementation Delays Reduce Net Program Benefits.

It should be clear from the foregoing discussion that recovery of costs is independent of realization of benefits, even where both occur in the same proceeding. On a present value basis, benefits in the future have less value than those today. Therefore, even if all benefits are eventually realized, any delay can still reduce the value of those benefits. SCE's adopted business case was based on meter deployment ramping up in January 2009. However, mass deployment did not begin in earnest until mid-September 2009, primarily due to delays in the availability of products that met SCE's functionality specifications. This delay has various impacts and implications for the ultimate cost- effectiveness of SmartConnect.

The delay in deployment had an asymmetrical impact on the benefits relative to the costs incurred and reflected in rates. SCE's advice letter request to update rates to reflect SmartConnect costs was deemed effective as of March 1, 2009.[81] Separately, SCE's authorized cost recovery proposal provided that SCE would record operational O&M benefits, on a per meter basis, eight months after meters were recorded in rate base (and thus earning a rate of return) to reflect a time lag between purchase and installation. Had deployment begun in January 2009, customers would have begun receiving a benefit via the ESCBA in August 2009. Instead, as a result of the delay, SCE did not begin recording operational O&M benefits to the ESCBA until April 2010. Thus, while SCE began charging customers for SmartConnect costs on March 1, 2009, customers did not start receiving any benefit from SmartConnect until over a year later.

[81] SCE Advice Letter 2320-E.

As discussed in Finding 1, the change in schedule not only caused delayed accrual of benefits, but it may decrease operational O&M benefits overall. Unless the CPUC orders SCE to continue recording deployment period operational O&M benefits beyond 2012 or SCE otherwise captures those benefits as post-deployment rate reductions, the benefits not yet recorded at the end of 2012 may be lost.[82]

Delayed meter installation also had a ripple effect in terms of both operational capital and all Demand Response benefits being realized, since nearly all benefits can only start accruing after meters are installed (for many benefits, the meter also had to be "program-ready," i.e., installed, tested, communicating, and customer being billed based on interval usage data). For instance, metering capital benefits - which were related to the avoided cost of electromechanical meters, deferred projects, and computers - should be reflected in SCE's annual post-Test Year revenue requirement advice letter filing. Based on DRA's review of these advice letters, capital benefits appear not to have begun accruing as of the end of 2010. According to the business case, DRA estimates that this amount should have amounted to more than $35 million by the end of 2010. Meanwhile SCE has, over the same period, booked over $345 million in meter-related capital expenditures – approximately 75% of the amount estimated in its adopted business case – to the ESCBA. Similarly, for Demand Response (DR) benefits, SCE reported zero participation in all of its DR programs, whereas the adopted business case assumed more than 386,000 customers would be enrolled in one or more of the

[82] PG&E's 2011 GRC Phase 1 settlement provided for PG&E's SmartMeter Benefits Realization Mechanism to be continued through the 2011 GRC cycle, with certain adjustments. *See* D.11-05-018 Attachment 1, section 3.5.2(c). SCE states in its 2012 GRC that SmartConnect operational benefits of $58 million are included in its 2013 forecast, but this is specific to the post-deployment period and does not remedy the reduced benefits due to the delay in deployment.

DR programs at the end of 2010. DRA estimates that, for the same time period, SCE has recorded between $15.5 and $41.6 million of DR-specific costs.

Even accounting for delayed deployment, it appears that DR benefits for Peak Time Rebate (PTR), Critical Peak Pricing (CPP), and Time-of-Use (TOU) are lower than estimated: as of July 31, 2011, SCE's reported participation rate for PTR is lower than the mid-2010 participation rate estimated in the business case by approximately 63%; for TOU the reported rate is less than 1% of the corresponding estimate in the business case;[83] still no customers have enrolled in CPP. This indicates a possible compounding effect of delayed deployment translating into *reduced* benefits, given that many SmartConnect benefits are cumulative in nature (i.e., the current year's level of benefits build upon the previous year's). The cumulative nature of these benefits also has cost-effectiveness implications with respect to the actual life of SmartConnect (as opposed to the business case life of 20 years): if the technology becomes obsolete or some other problem forces SCE to replace SmartConnect meters earlier than planned, a significant amount of benefits (estimated to occur in the final years of the business case) will also be lost.

Finally, delays were not limited to the availability of the meters: the Programmable Communicating Thermostat (PCT) and In-Home Display (IHD) programs have both been

[83] The adopted settlement included illustrative PTR, TOU, and CPP rate designs, but these rates were not formally approved until SCE's 2009 GRC Phase 2, in D.09-08-028. While previous decision D.08-09-039 adopted an illustrative default TOU rate for medium C&I customers, SCE subsequently settled in its 2009 GRC Phase 2 to offer an opt-in TOU rate for this class of customers. DRA was not a party to the Medium and Large Power Rate Group Rate Design Settlement Agreement. In its testimony DRA stated its preference for an opt-in TOU, but supported a default TOU with the ability to opt out and one year of bill protection.

significantly delayed because the communications protocol, Smart Energy Profile (SEP) 2.0 on which these devices are supposed to operate, has yet to be ratified by the ZigBee Alliance.[84] The benefits associated with these two programs constituted over 53% of total DR benefits during deployment. As with unforeseen costs, it is clear that unforeseen obstacles to achieving the benefits of SmartConnect also have a major impact on its cost-effectiveness.

6. Many Projected AMI Benefits Have a High Potential for Adverse Impacts for "At-Risk" Customers.

Two general types of features of the SmartConnect program could have adverse impacts on certain types of customers: use of the remote service connect/disconnect switch (RSS) and AMI-enabled time-varying rates. In the business case, both features promised significant net benefits for customers overall. Yet realization of these benefits may occur at the expense of low-income and other "at-risk" customers, such as customers who are ill, elderly, or unemployed.

Most SmartConnect meters are equipped with RSS, which enables service to be remotely disconnected and reconnected, thereby eliminating the need for a "house call" from an SCE field service representative.[85] This category of benefits of the RSS result in an estimated operational O&M benefit of over $1.310 billion during the SmartConnect program life due to

---

[84] The ZigBee Alliance is an association of companies working together to enable reliable, cost-effective, low-power, wirelessly networked, monitoring, and control products based on an open global standard.

[85] RSS is included for meters serving a load less than 200 amps, which includes most residential and some small business customers.

reductions in field service staff levels and other expenses to support field service visits.[86] This is the second largest of all benefits in the SmartConnect business case, after benefits associated with reduced meter reading costs. An additional category of benefits are those associated with using the RSS to more efficiently disconnect customers with unpaid bills, which total approximately $85 million.[87] As a result of these RSS benefits, SCE has proposed reducing connection costs for residential customers: from $26 to $15 for same-day service establishment and from $28 to $17 for same day reconnection.[88]

While supporting reduced connection and disconnection costs, consumer advocates are concerned that more efficient disconnection will pave the way for simply *more* disconnections, particularly for ill, elderly, and unemployed customers. SCE implemented more lenient collection policies for vulnerable customers in 2010,[89] and has stated that it plans to continue the current collection policies through 2014.[90] Of the three large IOUs, SCE's disconnection rates are the highest, even with the current lenient practices, for all residential customers including low-income customers.[91] Currently, two CPUC rulemakings are examining the

[86] For benefits B10.01 and a portion of B10.06, B29.02 and B30.01. This includes $65 million for deployment and $1.250 billion for post-deployment benefits.

[87] For benefits B23.01, B23.02, and B23.03. This total includes both deployment and post-deployment benefits.

[88] SCE Testimony in 2012 GRC, A.10-11-015, SCE- 4, Volume 1, p. 21 (mimeo).

[89] The CPUC's February 2010 Interim Order D.10-02-005 and July 2010 Disconnection decision D.10-07-048 required SCE to waive credit deposit requirements as a condition for service reconnection and to permit customers to spread unpaid amounts due over a minimum three month period. This decision extended the CPUC's February 2010 rules to waive credit deposits and extend longer terms for repayment of bills.

[90] SCE Testimony in 2012 GRC, A.10-11-015, SCE- 4, Volume 1, p. 11 (mimeo).

[91] Division of Ratepayer Advocates Report, *Status of Energy Utility Service Disconnection in California*, November 2009 and March 2011. *Also see* DRA Opening Comments of May 20, 2011 in Rulemaking 10-02-005.

impact of SCE's credit and collection practices on low-income customers.[92] In these proceedings, DRA has recommended that SCE limit disconnections of low-income customers to 6% or fewer annually.[93] DRA also recommended that SCE develop and offer Arrearage Management Programs in order to motivate improved bill payment behavior by forgiving past debt in exchange for timely payments.

A similar situation results from implementation of time-varying rate tariffs which are made possible by AMI-enabled interval usage data. The ability to provide price feedback to customers was a fundamental basis for the CPUC mandate for universal AMI deployment. SCE estimated savings from avoided energy and capacity due to implementation of time-varying rate tariffs would lead to benefits of nearly $[redacted] over the project life.[94] As described in more detail in Finding 5 above, the magnitude of the estimated benefits are changing over time, but what has not changed is that the benefits are predicated on the assumption that customers will reduce energy demand during times of peak system demand. However, some customers may be unable to react to the price signals and will face significantly increased energy costs as a result. DRA has described this issue extensively in many proceedings and

[92] The proceedings are R.10-02-005 on residential disconnection practices and A.11-05-017, SCE's application for renewal of its CARE rate discount and free energy efficiency retrofit.

[93] "Opening Comments of the Division of Ratepayer Advocates on the Administrative Law Judge's Ruling Providing Opportunity for Comments on Phase II Issues," May 20, 2011, in R.10-02-005, p. 4 (mimeo) and "Protest of the Division of Ratepayer Advocates," June 20, 2011, in A.11-05-017, p. 21 (mimeo).

[94] DRA estimates the benefit to be $[redacted]. SCE workpapers in A.07-07-026 clearly indicate that expected demand response benefits total over $3 billion. DRA subtracted the Programmable Communicating Thermostat (PCT) program and energy conservation from this total to obtain a value for PTR, CPP, and TOU benefits.

remains supportive of carefully crafted rate programs.[95] The design and implementation of dynamic rates programs must include provisions to protect "at-risk" customers; otherwise, the costs of SmartConnect to these customers in particular will be especially high.

Together, these two classes of fundamental AMI benefits (RSS and time-varying rates) represent over 30% of the estimated benefits of SmartConnect, and failure to realize even a small portion of these benefits will result in a program which is not cost-effective. The delicate balance between realizing of AMI-enabled systemwide benefits, while protecting low-income and "at-risk" customers, will be an ongoing challenge for regulators.

[95] DRA White Paper, *Time-Variant Pricing for California's Small Electric Consumers*, May 2011, p. 8 (mimeo). *Also see* "Testimony on San Diego Gas and Electric's Dynamic Pricing Application," A.10-07-009, pp. 1-8 to 1-10, 2-3 to 2-4, 2-9 (mimeo); and "Petition for Modification of the Division of Ratepayer Advocates, the California Small Business Association and the California Small Business Roundtable of Decision 10-02-032," pp. 4-6 (mimeo).

VI. Recommendations

Based on DRA's analysis and findings, we offer the following recommendations aimed at ensuring cost-effective AMI systems that will benefit customers.

1. Track AMI Benefits and Cost Impacts throughout the Life of the Investment.

The CPUC committed customers to investing over $5 billion in SCE's SmartConnect system alone, and it is incumbent upon the CPUC and IOUs to track costs and benefits to determine whether a net benefit is achieved. Regulators and policy makers should commit to ensuring that forecasted AMI system net benefits are ultimately realized. It is unlikely that regulatory staff involved with an AMI application will be available to review AMI-related cost requests across the full range of AMI-related proceedings, and over the full life of the AMI project. It is therefore necessary to ensure that utilities and regulators establish a formal method to track AMI costs and benefits. The CPUC should require utilities to establish a tracking mechanism to compare the original business cases to various AMI-related funding requests[96] made through applications, advice letters and other cost recovery mechanisms. The Commission also should require the utilities to provide status updates about the cost-effectiveness of their AMI investments. One vehicle for doing so might be the Smart Grid Deployment Plans required by P.U. Code § 8367. Additionally, DRA recommends that the following be included in any future large-scale long-term deployments utilizing a new technology, especially as Smart Grid technologies are adopted:

[96] This includes post-deployment costs and benefits identified in the utility's business case as well as incremental costs and benefits associated with technologies and programs that build on the original business case.

- Definition of costs and benefit categories consistent with the FERC accounting categories used in GRCs;
- Full documentation of the baseline state and capabilities of all systems (e.g., IT systems) and processes (e.g., billing and meter reading) impacted by the new technology;
- A list of specific deliverables which will be provided within the adopted deployment costs. This should be used as a baseline for subsequent requests for post-deployment or incremental technology-enabled costs;
- A single spreadsheet with the projected costs and benefits over the life of project, as adopted;[97] and
- Clear definition of the cost recovery process for all types of costs and benefits (e.g. post-deployment capital benefits due to DR).

2. Require that any Request for AMI-related Incremental Cost Recovery Includes a Showing of Increased Cost-Effectiveness.

In a recent proceeding, the CPUC ordered "[i]n future general rate cases, Pacific Gas and Electric Company shall not add a new type of cost to the revenue requirement without estimating and including in the revenue requirement the cost savings to be achieved by the

[97] The spreadsheet should express costs and benefits in the same terms as the AMI business cases, i.e., annual nominal dollar amounts for each cost / benefit item, broken out by O&M and capital. Additionally, applications should include the revenue requirements associated with these costs and benefits.

new type of cost or an explanation of the reasons there will be no cost savings."[98] Such an order should be issued in each proceeding where incremental AMI-related costs could be requested.

3. Ensure that Realization of Customer Benefits are Synchronized with Recovery of Costs.

PVRR analyses indicating net benefits can easily become outdated and invalid if benefit streams are delayed relative to cost streams. AMI and AMI-related programs should be designed to begin realizing benefits once mass deployment begins and regulators should ensure that both the magnitude and timing of forecasted benefits are reasonable. For example, support systems such as communication networks, back office IT systems, and marketing programs should be planned before mass deployment begins, so they can be launched concurrently with mass deployment. This recommendation applies both to the pending deployment of SoCalGas's AMI system and all AMI-enabled programs for which the utilities will seek cost recovery in the future. Ideally, cost recovery should be tied to benefit realization.

---

[98] PG&E 2011 GRC Phase 1 decision D.11-05-018, Ordering Paragraph 37, p.97 (mimeo). This is separate from the requirement in P.U. Code §451 that "[a]ll charges demanded or received by any public utility . . . for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable."

4. Condition Approval of Demand-side Management (DSM) Expenditures on Corresponding Adjustment to Supply-side Procurement Needs.

A major forecasted AMI benefit is the new capacity avoided by AMI-enabled Demand Response (DR) programs, but in times of over capacity, there is no new capacity to avoid. Rulings in both the DR policy (R.07-01-041)[99] and the LTPP (R.10-05-005) proceedings reflect the CPUC's intention that avoided cost realization is supposed to be a "full-circle" process (i.e., utilities' expenditures in demand-side programs will reduce their supply-side costs). DRA observes, however, that in California the utilities have been allowed to financially benefit from self-reported megawatt and megawatt-hour savings on the one hand (e.g., through the Energy Efficiency Risk/Reward Incentive Mechanism)[100] but still argue for new procurement on the other (e.g., PG&E's Oakley application).[101] If the impacts of AMI, DSM programs, and time-varying rates are not going to result in reduced procurement costs, regulators should not saddle customers with the redundant cost of these programs.

---

[99] "Scoping Memo and Ruling," R.10-05-006, Dec. 3, 2010, Attachment 1 ("Standardized Planning Assumptions (Part 1) for System Resource Plans"), pp. 10-11 (mimeo).

[100] D.12-01-019 approved an additional $68 million for a total of $211 in incentive awards to the IOUs over the 2006-2008 period. *See* "Decision Regarding the Risk/Reward Incentive Mechanism Earnings True-Up for 2006-2008," in R.09-01-019, December 16, 2010, p. 2 (mimeo).

[101] *See* A.09-09-021.

5. Create an Environment that Fosters the Development of New Benefits from the Sunk Cost in AMI.

Based on DRA's review of SmartConnect, it is likely that the net benefits promised in SCE's adopted program will not be fully realized, even if the recommendations above are implemented. An alternative way of making AMI cost-effective is to find new benefits which can be extracted with minimal incremental cost. Many such benefits related to increasing penetration of PEVs and DG[102] are anticipated through Smart Grid implementation, as well as full implementation of voltage monitoring and outage management.[103] Use of smart meters as a measurement and evaluation tool for Demand-Side Management (DSM) programs also has potential for incremental benefits. However, as mentioned in Recommendation 2 above, proposals requesting incremental AMI-related costs should be rejected unless they provide compelling evidence that they will provide incremental net benefits. Regulators must at the same time ensure that benefits promised in the AMI business case are not subsequently reused to justify other investments.

---

[102] DRA notes that increased penetration of DG does not actually provide a benefit as long as there is excess capacity. As noted in the previous recommendation, energy savings on the demand side should be reflected in reduced procurement of excess capacity. So far, this does not appear to be happening.

[103] Improved outage management was considered a benefit of SmartConnect, and SCE was allowed to recover costs associated with integration of AMI data with the outage management system. However, SCE has already requested $7.3 million in incremental funding in its 2012 GRC to upgrade its outage management system to further leverage AMI and repair defects. SCE also anticipates a more expansive upgrade in 2015-2020. *See* "Application of Southern California Edison Company (U-338-E) for Approval of its Smart Grid Deployment Plan," A.11-07-001, pp. 88-89 (mimeo).

6. Ensure the Needs of Low-Income and Other "At-Risk" Customers are Considered in Program Development and Implementation.

The use of a remote service switch (RSS) and implementation of time-varying rate tariffs provides nearly a third of the benefits expected from the SmartConnect program, but both can adversely impact certain types of customers. As discussed in Finding 6 above, DRA has made specific recommendations to protect "at-risk" customers in California. In addition, DRA has recommended more moderate introductory rates than are in the business case. Both of these recommendations reduce AMI benefits relative to those claimed in the business case, signaling a dynamic tension with other recommendations in this paper. This tension cannot be removed, but can be mitigated through a careful balance between the need for net benefits generally, with the protection for those in need. For certain classes of customers such as low-income customers and other "at-risk" customer groups, special efforts should be undertaken to ensure that such customers understand rate and bill impacts, and such customers should be encouraged to sign up if, and only if, they will benefit.

VII. Conclusion

The CPUC required California's large IOUs to file AMI applications and required a demonstration that AMI systems *could* produce net customer benefits. Initially, SCE found that AMI was not cost-effective for its customers, but AMI technological improvements in 2005 and 2006 led to the SmartConnect Application in 2007, which forecasted a very slim margin of lifetime net benefits on a present value basis. The CPUC authorized SmartConnect deployment costs of $1.634 billion, and SCE customers in aggregate have so far experienced a revenue requirement increase in excess of $193.1 million to cover these costs.[104] This is a real cost increase, one which will certainly rise as more meters are purchased and deployed, and as SCE begins to incur post-deployment costs. DRA's review of SCE's SmartConnect business case and analysis of the program to date revealed a number of findings.

First, total SmartConnect costs paid by customers will actually be more than $5 billion (nominally), accounting for post-deployment costs and the financing costs incurred over the 20 year life of the SmartConnect system. This total cost will be even greater if the cost of future AMI-enabled investments and programs are included. While SCE's incremental cost requests have thus far been relatively conservative, it is important to note that PG&E and SDG&E have so far requested much higher amounts in incremental AMI funding: PG&E has requested and received approval for funding in excess of $500 million, and SDG&E has received funding approval for over $93 million.

[104] $98.4 million in 2009 (AL 2320-E) and $94.7 million in 2010 (AL 2446-E); AL 2577-E authorizes a SmartConnect revenue requirement of $203.5 million ($205.8 million with franchise fees and uncollectibles) in 2011.

Second, it appears probable that the SmartConnect benefits forecasted by SCE will not be fully realized, and as a result, SCE customers will not experience the eventual rate *reductions* forecasted in the adopted business case. The CPUC only explicitly provided a cost recovery mechanism for $151.5 million in deployment benefits, and delayed implementation will result in only two-thirds of this amount being collected as planned. The remaining 98+% of benefits, estimated to be $7.437 billion, can only be realized through a plethora of cost reductions in multiple proceedings. While this finding is based on a limited analysis early in a 24 year program, the delays and reduction in forecasted benefits are sufficient to erase the razor-slim margin of net benefits adopted by the CPUC. Note that this finding relates to the 50 specific benefits defined by SCE in 2006 and does not include new and incremental SmartConnect related net benefits that may yet be provided.

Third, the cost/benefit analysis in the SmartConnect business case, and this report, generally relates to SCE customers as a whole, and the impacts on individual customers can vary substantially. For example, customers can use their smart meter to reduce electricity usage and reduce their bills, even taking into account the rate increase for SmartConnect costs. In contrast, other individuals will be subjected to adverse impacts due to remote disconnection and higher rates during hot summer days. Evaluation of any AMI program needs to consider individual impacts and protect “at-risk” customers.

Finally, in performing this analysis, DRA found many impediments to tracking cost-effectiveness during SmartConnect program implementation. This is in spite of SCE having a generally well defined business case and being responsive to DRA’s discovery requests. Knowledgeable and diligent regulators will be hard pressed to limit actual lifecycle costs to the forecast estimates. It will be even more difficult to ensure the promised benefits are realized by customers as a net reduction in their rates, since regulators must actively look for cost reductions that may not be clearly identified by the utility. DRA offers recommendations intended to aid the ongoing evaluation of AMI programs by enabling transparent and ongoing tracking of cost-effectiveness.

The overall point of this report is not to fault SCE for performance to date or to propose retroactive ratemaking, but rather to highlight the many challenges to be overcome if AMI-related customer benefits are to be realized. Utilities have a clear financial motivation to quickly and fully recover all authorized expenditures through rate increases, but not such clear motivation to ensure that anticipated benefits are realized through rate decreases. Given this fundamental asymmetry, the CPUC has the responsibility of ensuring the investment in AMI ultimately yields a net benefit to customers. California IOUs have been authorized to expend over $5.3 billion to *deploy* AMI systems,[105] and it is too late to keep these expenses out of rates. However, billions more will be requested for *post-deployment* and incremental costs. The ultimate value or financial burden of AMI will be determined by the CPUC's actions regarding each and every one of these requests.

[105] This figure includes the $1.0507 billion approved for SoCalGas's (gas-only) AMI system (D.10-04-027). The Commission approved $572 million for SDG&E (D.07-04-043); up to $1.6 billion (D.06-07-027), plus $466.8 million (D.09-03-026 – upgrade) for PG&E's gas and electric AMI deployments.

APPENDIX 1: Glossary

AMI	Advanced Metering Infrastructure. AMI is also commonly referred to as "smart meters," although AMI encompasses meters and other equipment, software, and processes necessary to make the meters fully functional. SCE's SmartConnect is a specific example of an AMI system.
Capital Expenditure	An expenditure that is treated as an accounting asset and depreciated over time. They also are placed in rate base, and customers pay a rate of return on these expenditures. Capital expenditures include all long-term assets, which are expected to be "used and useful" over an extended period of time; for instance IT hardware and software physical plant, and related equipment, etc. In other words, a capital expenditure is a capital investment (i.e., part of rate base), upon which the utility is allowed to earn a profit (commonly referred to as rate of return). The capital investment shows on the utility's balance sheet.
CEC	California Energy Commission
CPP	Critical Peak Pricing. A time-varying rate in which customers are notified, typically on a day-ahead basis, that their rates will increase during a specified "event" (usually four to six hours during the late afternoon). CPP events are typically called in anticipation of abnormally high demand or other system constraints.
CPUC	California Public Utilities Commission
CSBU	Customer Services Business Unit. The organization at SCE which includes meter reading, field service, and billing, which is most affected by the SmartConnect program.

Demand Response (DR)	Gives individual electric customers the ability to reduce or adjust their electricity usage in a given time period, or shift that usage to another time period, in response to a price signal, a financial incentive, or an emergency signal. Programs designed to reduce energy demand during peak usage periods, which drives procurement of new capacity. This includes time-varying rates/tariffs, programs designed to generate load control and price-responsive demand response, and in certain cases energy conservation. Generally used in reference to DR programs adopted by the CPUC.
Deployment Costs/ Benefits	Costs/benefits which have been approved by regulators and for which a cost-recovery mechanism has been established. For SmartConnect, this originally referred to costs/benefits incurred during the time period beginning September 18, 2008 through December 31, 2012[106]. It also describes the costs/benefits required to be provided by the functionality, features, and programs proposed in SCE's application (adopted in D.08-09-039).
DRA	Division of Ratepayer Advocates
DR-specific Costs/ Benefits	As opposed to operational costs/benefits (see below), DR-specific costs are those that are not necessary for AMI deployment, *except* to implement and administer DR programs. DR benefits are benefits that could only occur as a result of these programs.
ERRA	Energy Resources Recovery Account
ESCBA	Edison SmartConnect Balancing Account. Also referred to as the SmartConnectBA by SCE.
GRC	General Rate Case

[106] SCE has proposed modifying the pervious definition of SmartConnect deployment costs to extend beyond December 31, 2012. See SCE testimony in the TY 2012 GRC, Exhibit SCE-4, volume 1, page 30.

HAN	Home Area Network
IHD	In-Home Display
IOU	Investor owned utility
Incremental AMI-enabled Costs/ Benefits	Requests for new AMI enabled programs, operational costs, or capital investments which promise benefits beyond those quantified in the original business case. "Incremental" refers to those costs and benefits that were either excluded or underestimated in the original business case for various reasons (e.g., unforeseen costs).
Meter Month	A term used to amortize deployment period benefits into rates. For each new meter, it is the number of months the meter has been in service, as counted starting 8 months after the meter was purchased. For example, 10 meters installed May 1, 2009 would generate 120 meter months as of December 31, 2010.
Operational Costs/ Benefits	In terms of the AMI business cases, operational costs are all the costs necessary to implement and administer AMI deployment. Operational benefits are all the benefits resulting from such costs. In R.02-06-001, the CPUC directed the electric IOUs to analyze AMI deployment scenarios that included operational costs/benefits only, and scenarios that included both operational and DR-specific costs/benefits.
Operations & Maintenance (O&M) Expense	An accounting expense that shows on the utility's income statement (i.e., annual profit and loss statement). O&M expenses are not included in rate base. O&M expenses include, for example, purchased power and fuel; customer accounts, services, and marketing expenses; and administrative and general expenses.
PCT	Programmable Communicating Thermostat

Post-Deployment Costs/ Benefits	Costs/benefits, other than deployment costs, in the adopted cost-benefit analysis and which have corresponding benefits in the AMI business case. For SCE, those costs/benefits incurred during the time period beginning January 1, 2013.[107]
PTR	Peak Time Rebate. Demand Response (DR) program in which customers are notified, typically on a day-ahead basis, that they may receive rebates for reducing their electricity usage during a specified "event" (usually four to six hours during the late afternoon). PTR events are typically called in anticipation of abnormally high demand or other system constraints.
PVRR	Present Value Revenue Requirement
RSS	Remote Service Switch (connect/disconnect). A feature of SmartConnect meters installed on services less than 200 amps which allows the utility to end, and restart electrical service remotely, without sending a service technician.
SCE	Southern California SCE
SmartConnect	Southern California SCE's brand name for their AMI system.
SPP	Statewide Pricing Pilot
TOU	Time-of-Use. A time-varying rate in which prices vary depending on the season and time of day. TOU prices are typically higher during "peak" and "semi-peak" hours, when demand is expected to be higher, as opposed to "off-peak" hours. In contrast to CPP, TOU does not include significantly higher prices that can be applied to rates on a day-ahead basis.

[107] Ibid.

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:

---

[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.
>
> 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]

[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]

[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]

---

[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.
>
> 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?
>
> A. I think we would not.
>
> Q. How about three years?
>
> A. I think we would not.
>
> Q. You think you're at your minimum right now?
>
> 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.
>
> 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.
>
> 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?
>
> 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.
>
> 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.
>
> 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

[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.

---

[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

[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]

---

[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. <u>MEA</u>

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

---

[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

[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]

[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]

[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

[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?"

---

[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]

---

[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

[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.

[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

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

[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

---

[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,

[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.

[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,

---

[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

DEPARTMENT OF ENERGY

DATA ACCESS AND PRIVACY ISSUES RELATED TO SMART GRID TECHNOLOGIES

October 5, 2010

TABLE OF CONTENTS

INTRODUCTION AND EXECUTIVE SUMMARY

This report by the Department of Energy (DOE) complements DOE's companion report, *Informing Federal Smart Grid Policy: The Communications Requirements of Electric Utilities*.[1] Both reports are also components of the federal government's much broader efforts to facilitate the adoption and deployment of various Smart Grid technologies. These ongoing broader efforts have encompassed many agencies including many operational units within DOE, the Federal Communications Commission (FCC), the Federal Energy Regulatory Commission (FERC), the National Institute of Standards and Technology (NIST), and the National Science and Technology Council Committee on Technology's Subcommittee on Smart Grid.

This report and its companion report also respond to recommendations directed toward DOE in the National Broadband Plan (the "NBP"), authored by the FCC at the direction of Congress.[2] The NBP seeks to ensure that every American has access to broadband capability. The NBP also includes a detailed strategy for achieving affordability and maximizing use of broadband to advance consumer welfare, civic participation, public safety and homeland security, health care delivery, energy independence and efficiency, education, entrepreneurial activity, job creation and economic growth, and other national purposes.[3] As part of this strategy, the NBP made recommendations to various Federal agencies, including DOE. In particular, the NBP recommended that DOE evaluate the overall communications needs of the Smart Grid, consider consumer-data-accessibility policies when evaluating Smart Grid grant applications, and report on the states' progress toward enacting consumer data accessibility and develop best practices guidance for states. This report implements the latter two recommendations, while the companion report implements the first recommendation.

Smart Grid technologies will be a critical long-term component of a more interactive, robust, and efficient electricity generation, transmission and usage system. Moreover, the advanced, state-of-the-art electrical grid that these technologies will create will be an important component of an overall national energy, economic, and security strategy predicated upon reasserting U.S. leadership in the race to develop cleaner, sustainable, and secure sources of energy—a race that Secretary of Energy Chu has called "a Second Industrial Revolution."

As DOE has emphasized, the promise of the Smart Grid is enormous and includes improved reliability, flexibility, and power quality, as well as a reduction in peak demand and transmission costs, environmental benefits, and increased security, energy efficiency, and durability and ease

[1] *See* Department of Energy, *Informing Federal Smart Grid Policy: The Communications Requirements of Electric Utilities*, October 5, 2010, available at http://www.gc.energy.gov/1592.htm. This complementary report provides a more detailed summary of both the operation of Smart Grid technologies like advanced metering and the federal government's multifaceted efforts to promote their adoption and deployment.
[2] The Plan, developed pursuant to the American Recovery and Reinvestment Act of 2009 (P.L. No. 111-5), was issued on March 16, 2010 and is available at http://www.broadband.gov/plan/.
[3] *Id.*

of repair in response to attacks or natural disasters. But DOE also recognizes that long-term success of Smart Grid technologies depends upon understanding and respecting consumers' reasonable expectations of privacy, security, and control over who has access to potentially revealing energy-usage data.

DOE believes that privacy and access, in the context of a Smart Grid, are complementary values rather than conflicting goals. The practical impact of a Smart Grid depends on its capacity to encourage and accommodate innovation while making usage data available to consumers and appropriate entities and respecting consumers' reasonable interests in choosing how to balance the benefits of access against the protection of personal privacy and security. This report seeks to assist both policymakers and private and public entities interested in understanding how legal and regulatory regimes are evolving to better accommodate innovation, privacy and data-security. To that end, this report surveys industry, state, and federal practices in this evolving area to alert industry leaders, state regulators, and federal policy makers to trends and practices that seem most likely to accommodate all of these values and maximize the value of Smart Grid technologies.

This Report consists of two main components. The next section, *Key Findings*, summarizes DOE's impressions of the information it collected in the spring and summer of 2010 during its proceeding on the data-privacy and data-security issues raised by Smart Grid technologies like advanced metering. In particular, this section provides a coherent summary of developing trends, consensuses, and potential best practices emerging as States use or adapt existing legal regimes to accommodate the deployment of Smart Grid technologies. The second section, *Summary of Public Comments and Information*, provides a more comprehensive summary of the comments, both written and transcribed, that DOE received in response to the Request for Information ("RFI") and during the public roundtable discussion conducted during the preparation of this report.

Overview of Data Access and Privacy Concerns

Recognizing and addressing the significant concerns with access to and privacy protection for energy usage data are critical to the development of U.S. Smart Grid policies because of the enormous potential of consumer and authorized third party access to energy consumption data through the use of Smart Grid technologies, and the continued importance of utility access to such data.

Advances in Smart Grid technology could significantly increase the amount of potentially available information about personal energy consumption. Such information could reveal personal details about the lives of consumers, such as their daily schedules (including times when they are at or away from home or asleep), whether their homes are equipped with alarm systems, whether they own expensive electronic equipment such as plasma TVs, and whether they use certain types of medical equipment. Consumers rightfully expect that the privacy of this information will be maintained. The proprietary business information of non-residential customers could also be revealed through the release of energy consumption data, resulting in competitive harm. Studies conducted by utilities and consumer advocates have consistently shown that privacy issues are of tremendous import to consumers of electricity.

At the same time, access to consumer data continues to be of importance to utilities for operational purposes and to achieve the important national goals, discussed above, that Smart Grid technologies will advance. In addition, access to such data by consumers and authorized third parties has significant potential to enable American consumers to understand their energy use, and thus become more proactive in managing that use, ultimately saving money on their energy bills and becoming more efficient consumers of energy.

DOE recognizes that issues of data access and privacy are not entirely new. DOE commends the utilities' strong track record of protecting the privacy of customer data and acknowledges the traditional responsibility of state utility commissions in regulating issues associated with data privacy. The findings set forth in this report build up the continuing efforts of these entities to protect customer privacy, as well as the efforts of third party service providers and consumer groups to foster responsible data access to achieve the goals of Smart Grid. DOE believes that these findings will be applicable to issues of privacy and access that will continue to remain at the forefront as the technologies associated with Smart Grid continue to evolve.

Summary of Recommendations

DOE's recommendations are discussed more fully in the section that follows. In summary, however, DOE notes that consumer education about the benefits of Smart Grid and the use of Smart Grid technologies will be of significant important to the success of Smart Grid. The pace of deployment will also be important and should not outpace consumer education.

This is particularly true given that Smart Grid technologies can generate very detailed energy consumption information. Because of its detailed nature, such information should be accorded privacy protections – and the accord of these protections will do much to increase consumer acceptance of Smart Grid. While utilities need access to this energy consumption data for operational purposes, both residential and commercial consumers should be able to access their own energy consumption data and decide whether to grant access to third parties. In addition, the special circumstances of certain populations, such as rural, low-income, minority and elderly populations, must be considered in any Smart Grid deployment strategy.

States should also carefully consider the conditions under which consumers can authorize third-party access. Commenters to this proceeding generally agreed that these conditions should include a prohibition on disclosure of consumer data to third parties in the absence of affirmative consumer authorization, and that the authorization should specify the purposes for which the third party is authorized to use the data, the term of the authorization, and the means for withdrawing an authorization. Commenters also generally agreed that authorized third parties should be required to protect the privacy and security of consumer data and use it only for the purposes specified in the authorization, and that states should define the circumstances, conditions, and data that utilities should disclose to third parties.

Issues of third-party access for which consensus proved harder to achieve include how consumers should authorize third-party access and how (though not whether) utility liability should be limited when utilities are required to disclose data to authorized third parties, as well as applicable complaint procedures once third-party access has been authorized, and the specific data that utilities should be required to disclose to authorized third parties. In addition, commenters did not reach consensus on whether utilities could charge a fee for providing third-party access to consumer energy data, and whether authorized third-party service providers should be required to obtain further informed consent before disclosing such data. State certification requirements for third parties also remained an open issue.

To assist in the discussion and resolution of these issues, DOE proposes to create a web portal and act as a clearinghouse for data and information on Smart Grid data access and protection.

KEY FINDINGS

This section summarizes and records DOE's impressions of the results of its efforts to collect and analyze diverse perspectives on the current state of data security[4] and consumer access and privacy issues associated with the ongoing development and deployment of "Smart Grid" technologies. In so doing, it provides federal, state and local policymakers, as well as utilities and third-party providers of energy management services, with a concise, broad overview of the current state of ongoing efforts to assess the legal and regulatory implications of the data-security and data-privacy issues that were identified during a public information-gathering process conducted by DOE in the spring and summer of 2010. In this document, DOE attempts to provide a measure of certainty for all Smart Grid participants on issues where there is consensus, as well as highlight the pros and cons of various approaches where debate still exists.

DOE stresses the intended audience and the legal and regulatory focus of this report because efforts to encourage the deployment of Smart Grid technologies will depend significantly upon two factors. *First*, the success of such efforts depends upon the development of legal and regulatory regimes that respect consumer privacy, promote consumer access to and choice regarding third-party use of their energy data, and secure potentially sensitive data to increase consumer acceptance of Smart Grid. *Second*, the success of such efforts also depends upon the development of appropriate technical standards and protocols for promoting privacy, choice, and the secure, interoperable transfer and maintenance of sensitive data.

This report focuses on the first of these challenges. Federal efforts to investigate the second set of technical issues and promote the development of standards for addressing them are also underway. Those seeking analyses of the technical issues should consult publications like the *Guidelines for Smart Grid Cyber Security: Vol. 2, Privacy and the Smart Grid,* released by the National Institute of Standards and Technology in August 2010.[5]

---

[4] The term "data security" in this report means the ability to protect the confidentiality, integrity and availability of the data. The term refers primarily to securing consumer data in the interests of privacy, and does not seek to encompass or answer more generalized Smart Grid cyber security issues. The systemic pursuit of cyber security throughout the Smart Grid serves to reinforce consumer data security, but the topic is dealt with narrowly here.
[5] Cyber Security Working Group (CSWG), Smart Grid Interoperability Panel (SGIP), *Guidelines for Smart Grid Cyber Security: Vol. 2, Privacy and the Smart Grid* (National Institute of Standards and Technology Interagency Report NISTIR7628, August 2010). This document is available at:

The proceedings conducted by DOE and the findings set forth in this report are particularly relevant because legal and regulatory infrastructures are now developing rapidly as various states and localities either begin to deploy Smart Grid technologies, or prepare to do so soon. These Smart Grid technologies have attracted widespread attention from policymakers, investors, industries and consumers who realize that a more interactive electrical grid can promote not only more efficient and transparent energy use, but also the sorts of unpredictable innovations often associated with the Internet.[6] Moreover, these technologies have important implications for the nation as a whole and for the continued development of our overall national energy strategy. An updated, more flexible and more interactive electrical transmission and distribution system will be critical to the long-term success of our move towards sustainable energy—particularly if plug-in electrical vehicles become widely used.[7]

At the same time, it is important to recognize the key role played by the States in the regulation of electrical utilities and consumer privacy.[8] In this report, DOE recognizes that the States will continue to play their traditional leading roles in regulating the deployment of Smart Grid technologies. DOE also believes that an effective partnership between federal and state agencies would be beneficial to broadly support and facilitate the development and deployment of a wide range of Smart Grid technologies.

Promoting American innovation in the development and deployment of cleaner, more sustainable and more domestic energy-generation technologies is a critical, long-term national priority. Moreover, in the long run, a "smarter," more flexible and robust electrical transmission-and-distribution system is unquestionably a prerequisite to the achievement of this priority. As exemplified by the Recovery Act, Energy Independence and Security Act of 2007 and other authorities, DOE has an important role in promoting the development, deployment and evolution of Smart Grid technologies. One means for DOE to do so is to carefully study diverse State and local efforts to develop and deploy these technologies and act as a "clearinghouse" for data that will help State and local officials, as well as private enterprises, identify the most promising research, development, regulatory and deployment strategies.

---

http://csrc.nist.gov/publications/PubsNISTIRs.html#NIST-IR-7628 (last visited September 28, 2010). The SGIP is administered under a contract from NIST, funded through DOE ARRA funding transferred to NIST to support NIST activities under the Energy Independence and Security Act of 2007 (EISA).

[6] *See, e.g.*, Consumer Electronics Association (CEA) at 1 (agreeing that Smart Grid technologies will "play a critical role in achieving national priorities like enabling new ways to enhance energy efficiency…"); Utilities Telecom Council (UTC) at 1 (noting that smart energy grids will "create an environment in which consumers will have greater abilities to manage their own energy usage and utilities will have new tools to affect grid-wide energy efficiencies"); National Association of State Utility Consumer Advocates (NASUCA) at 22-23 (discussing the need for privacy protections that take into account future developments involving not only electric vehicles but also other unforeseen devices); Google, Inc. (Google) at 1 (noting that consumer access to energy consumption data could lead to "countless new products and solutions to help consumers save energy and money"); Jeff Osborne, et al., *A Primer on the Smart Grid* (Thomas Weisel Partners, Aug. 6, 2009) (discussing potential investment opportunities associated with Smart Grid technologies).

[7] Tendril Networks, Inc. (Tendril), Data Privacy Public Meeting Transcript (PTR) at 21-22 (noting the relatively significant amount of energy used by electric vehicles).

[8] DOE recognizes that typically, States have jurisdiction over investor-owned utilities. Such utilities provide service to over 68% of electric utility customers. Most of the analysis and recommendations set forth in this report, however, are equally applicable to public and cooperative electric utilities.

In light of the above, DOE finds that:

First, this state-federal partnership model follows from the federal government's overall strategy towards clean energy technologies. In the Recovery Act, the Nation made an unprecedented investment in sustainable energy and high-quality jobs by, among other initiatives, directing DOE to support the development and deployment of a wide array of differing Smart Grid technologies and approaches. Through the Act, DOE will promote the transition of our Nation, with its diverse local geography and resources, towards more sustainable energy sources, as well as the creation of breakthrough technologies that will promote economic growth and exports during the 21st century.

Second, this partnership model is well advised given that Smart Grid technologies are only beginning to be widely deployed, and allowing for experimentation is a sound policy strategy. After all, our experience with Internet technologies strongly suggests that it may be difficult or impossible to predict the uses to which a "smarter" and more interactive electrical grid will ultimately be put. Our federal system of state and local governments was intended to provide opportunities to experiment so debates about the relative merits of differing approaches can be assessed by practical experience.

Third, Smart Grid technologies offer enormous potential benefits to the nation, to electrical utilities, and to consumers. Because the deployment of such technologies will impose costs that will likely be recovered from consumers, however, there is a strong case that any such decisions should be evaluated at the state level where the relevant agency can evaluate whether such investments are justified.

It should be noted that among the many Smart Grid technologies, advanced meters or "smart meters" figure heavily in discussions about consumer data and privacy. Many other components of a Smart Grid are potentially relevant to consumer privacy, but the advanced meter's ability to measure, record and transmit granular individual consumption, and its presence at the traditional boundary between the utility and the consumer, make it a focal point of this report. A Smart Grid, of course consists of hundreds of technologies and thousands of components, most of which do not generate data relevant to consumer privacy.

As part of its role in facilitating the continued development of an effective energy policy strategy for the 21st century, DOE therefore sets forth the following "Key Findings," which fall into two categories. First, some findings identify both situations in which participants in this proceeding and DOE's own analysis of relevant state laws, practices, and secondary sources suggest fairly broad agreement on particular issues. Second, other findings highlight situations in which the same sources suggest fairly broad agreement on the importance of confronting particular questions—even if those sources do not yet suggest broad agreement as to the best answers to those questions.

As an initial matter, DOE emphasizes the extent to which there was substantial agreement on matters related to data access, consumer privacy, and Smart Grid technologies. DOE was surprised about the extent of this agreement, given that issues related to privacy can be divisive, and relevant state laws on consumer privacy and utility regulation can differ significantly as a result. Many Smart Grid technologies are just emerging or being widely deployed, and it is inherently difficult to predict just what net benefits and services will ultimately arise from a more interactive energy transmission system that provides more granular energy-consumption data. Consequently, it was encouraging to note the extent to which states, localities, private and public electrical utilities, potential third-party service providers, and information technology and consumer-electronics providers were not only thinking carefully about these issues and participating in federal efforts to enhance coordination, but also reaching somewhat similar conclusions.

Consumer education and flexibility in both technology and pace of deployment will be critical to the long-term success of Smart Grid technologies.

Commenters voiced broad consensus on this principle. Deployment of Smart Grid technologies offers important long-term benefits for both consumers and the electricity generation, transmission and usage system. These technologies can reduce energy costs for individual American consumers and across the American economy. They are also critical to our long-term efforts to create high-quality jobs and promote sustained economic growth by re-asserting American ingenuity and technological leadership in the global movement to transition energy production and consumption towards cleaner, more sustainable, and more secure energy sources.

Moreover, important long-term benefits of Smart Grid technologies arise directly from the more intelligent electrical-metering-and-usage-monitoring technologies that will be the focus of this report.[9] For example, smarter metering technologies and other customer-facing technologies (commonly referred to as home area networks, or HANs) could enable technologies that could reduce the overall costs of generating electrical power and encourage shifting load from peak to off-peak by rewarding consumers who curtail their energy usage during “critical peak-load” periods when particularly heavy demand radically increases the overall cost of electrical generation as particularly expensive generation methods must be brought online quickly. Smart metering can also encourage consumers to use less energy by providing consumers with information (through in-home displays and other devices) about energy usage. Enhancing consumers’ ability to understand and manage their energy consumption will also be important to efforts to better integrate variable or intermittent renewable energy-generation technologies—like wind and solar—into our overall energy transmission and generation system. Similarly, the advent and use of electric vehicles will create new potential stresses on our use of electric power that can be minimized through Smart Grid technologies.

In discussing the importance of consumer education, commenters in this proceeding consistently stressed that an overly prescriptive “top-down” approach to attaining these long-term national goals could prove unhelpful, or even backfire. In particular, commenters consistently identified three factors that, taken together, suggest that both patience and flexibility will be critical

[9] In this report, DOE uses the terms “intelligent electrical-metering-and-usage-monitoring” and “advanced metering” to refer, generally, to a wide range of metering technologies including AMR and AMI. These technologies vary widely in their capabilities, implementation, and costs.

components of any overall or long-term national strategy towards Smart Grid technologies generally and advanced metering technologies in particular.

First, both governmental and private proponents of smart-grid technologies and the advanced services that they can support should recognize that consumer education will be a critical component of successful efforts to promote the widespread adoption and deployment of various forms of intelligent electrical-metering-and-usage-monitoring technologies. To a considerable extent, the pace at which "smarter" metering systems can be deployed depends ultimately upon the extent to which the citizens of a given state or jurisdiction conclude that they will benefit by investing in advanced metering technologies. Consumer education and outreach to consumer advocates—some of whom still view advanced metering technologies with suspicion—will thus be critical components of efforts to promote the adoption of Smart Grid technologies.[10]

Second, states and localities will need the flexibility to carefully balance the costs, benefits, and deployment schedules of a wide array of intelligent electrical-metering-and-usage-monitoring technologies that vary significantly in their level of sophistication. Notably, states and localities will need the flexibility to consider the costs and benefits of requiring utilities deploying such technologies and home energy management systems to provide more or less granular data, and the willingness of the consumers in a particular jurisdiction to support the deployment of such technologies.[11]

Third, both of the preceding concerns will be heightened in the context of utilities that provide services to predominately rural or economically disadvantaged customers. In such areas, deployment costs may be unusually high, or relatively high compared to income levels, customer bases may be particularly cost-sensitive, and the need for focused consumer education may be greater.[12]

---

[10] *See, e.g.*, CEA at 4; Office of Consumer Counsel, Colorado Department of Regulatory Agencies (CO OCC), PTR at 12-13, 32, 53, 102; Northwestern Energy (NW Energy), PTR at 13-14, 62; TechNet, Inc. (TechNet), PTR at 16-17; Sacramento Municipal Utility District (SMUD), PTR at 29, 48, 97; Telecommunications Industry Association (TIA) at 3-4; Tendril, PTR at 58-59 (discussing the gap between increased costs to consumers and the benefits consumers see from Smart Grid roll out); DTE Energy Company (DTE), PTR at 83-84 (same).

[11] *See, e.g.*, American Public Power Association (APPA) at 7; Avista Corporation (Avista) at 2; Edison Electric Institute (EEI) Reply at 11; NASUCA at 15-16; NW Energy, PTR at 48; Sawnee Electric Membership Corporation (Sawnee), PTR at 47. *See also* National Rural Electric Cooperative Association (NRECA) at 2 ("Cooperatives are widely embracing numerous Smart Grid technologies and have been recognized as leaders in integrating advanced grid technologies. For many Cooperatives, [AMI], distribution automation, and software integration are among the Smart Grid technologies that make sense. The operational benefits of [such] technologies are often greater in rural areas with low population densities. Low density increases the costs of meter reading, outage response, system maintenance, and distribution system losses. Advanced technologies help Cooperatives to address these issues and thus provide real benefits to consumers including lower distribution costs and fewer and shorter outages. (Citing F.E.R.C. Ann. Rep. on the Assessment of Demand Response and Advanced Metering 8 (Dec. 2008), *available at:* http://www.ferc.gov/legal/staff-reports/12-08-demand-response.pdf).

[12] *See* Institute for Electric Efficiency (IEE), *The Impact of Dynamic Pricing on Low Income Consumers* (June 2010) ("Based on bill impact simulations and the results review from four pilots and one full-scale program, we conclude that low income customers will benefit from dynamic pricing."). *See also* comments of Joint Center for Political and Economic Studies (Joint Center); Consumers Union, National Consumer Law Center, and Public Citizen (Joint Consumer Comment) at 5-6; TechNet, PTR at 31-32.

To be clear, most participants in this proceeding—including many of those who offered the cautionary notes summarized above—were very supportive of the development and deployment of Smart Grid technologies. Nevertheless, many also stressed that because the short-term costs of deploying such technologies will tend to precede their long-term benefits, it will be important for policymakers at all levels to recognize the importance of educating consumers and ensuring that the extent and the pace of deployment does not outpace consumer attitudes, which may vary significantly and depend upon local circumstances.

Many Smart Grid technologies can generate highly detailed or "granular" energy-consumption data that should be accorded privacy protections because it is both potentially useful and sensitive.

This principle also generated broad consensus among commenters. Data about the energy use of a given household can be a powerful tool for increasing efficiency, troubleshooting, and lowering overall costs because each of the many household devices and appliances that consume electrical power tend to do so in a way that can enable a sophisticated analyst—given enough sufficiently granular energy-usage data—to identify the contributions of particular appliances and devices to overall energy usage and to determine whether those contributions are consistent with those of an efficiently-operating appliance or device.[13] The current state of the art, in terms of the granularity of data collected by utilities using advanced metering, cannot yet identify individual appliances and devices in the home in detail, but this will certainly be within the capabilities of subsequent generations of Smart Grid technologies.

Such data, termed consumer-specific energy-usage data ("CEUD") by many commenters, has enormous potential to enable utilities or other third-party service providers to help consumers significantly reduce energy consumption, avoid costly breakdowns and repairs, and reduce the overall complexity of running a modern household full of increasingly complex and interactive devices and appliances.[14]

Because such data can also disclose fairly detailed information about the behavior and activities of a particular household, however, there was also broad consensus that the collection of CEUD raises privacy implications that should be acknowledged and respected during the development of intelligent electrical-metering-and-usage-monitoring technologies.[15] It is the energy usage data itself *and* the ability to tie that data to an individual or household that makes the data particularly sensitive.

[13] *See, e.g.,* Tendril, PTR at 22, 26, 33-34, 75; Whirlpool Corporation (Whirlpool), PTR at 75; Honeywell International, Inc. (Honeywell) at 8-9.
[14] *Id.* For comments directed to the definition of CEUD and other relevant types of data, *see, e.g.,* Silver Spring Networks (Silver Spring) at 1-3; Avista at 5; NASUCA at 4; EEI at 3, 6; Cleco Power, LLC (Cleco) at 2; DTE at 2-3; Demand Response and Smart Grid Coalition (DRSG) at 1; CPower, Inc. (CPower) at 1.
[15] *See, e.g.,* NARUC at 2 (stating that "[w]hile the deployment of smart grid technologies may empower the consumer and provide more options, it also poses significant privacy issues that need to be considered and resolved by regulators").

Many commenters also agreed on a closely related principle: At any given moment, many consumers are likely to have widely varying views about how they want to balance the privacy and efficiency implications of energy-usage data generated by certain Smart Grid technologies, and their views may evolve significantly over time as real-world experience demonstrates added-value by revealing the relative advantages of differing sets of choices. Consequently, consumers should have rights to protect the privacy of their own CEUD and control access to it.[16] Well-designed implementations of Smart Grid technologies should also empower individual consumers to make a wide array of choices about whether or how to manage their own energy-consumption data via home energy management systems.[17]

Utilities should continue to have access to CEUD and to be able to use that data for utility-related business purposes like managing their networks, coordinating with transmission and distribution-system operators, billing for services, and compiling it into anonymized and aggregated energy-usage data for purposes like reporting jurisdictional load profiles.

Many commenters stressed not only that the utilities' use of CEUD will support critical functions, but also that the importance of utility access to and use of such data is likely to increase significantly as we move towards more sustainable and non-polluting means of energy generation and consumption like renewable energy sources and plug-in electrical vehicles.[18] In particular, utility access to consumer data will be important to efforts to better integrate variable or intermittent renewable energy-generation technologies into our overall energy transmission and generation system. Moreover, the charging of electrical vehicles—though it may tend to occur during "off-peak" hours in most jurisdictions—may impose significant challenges that will require utilities to carefully monitor electrical consumption across their networks as such vehicles become more popular.[19]

---

[16] *See, e.g.,* APPA at 5, 7; Avista at 1-3; AARP Reply at 4; Baltimore Gas & Electric (BG&E) at 2; Cleco Power LLC ("Cleco") at 1-2; CEA at 2-4; Joint Consumer Comment at 8; CPower at 1-2; DRSG at 2-3; EEI at 8-11, 17; EEI Reply at 6-7; Elster Solutions (Elster) at 1; EnerNOC, Inc. (EnerNOC) at 2-3; Exelon Corporation (Exelon) at 2; Florida Power & Light Company (FPL) at 4-5; Google at 1; Honeywell at 2-3; Idaho Power Company (Idaho Power) at 4-6; Joint Center at 11-12; NASUCA at 8-9, 16; NRECA at 7; Oncor Electric Delivery Company, LLC (Oncor) at 3-5; Pepco Holdings, Inc. (Pepco) at 1-2; Southern California Edison (SCE) at 1-2; San Diego Gas & Electric Company (SDG&E) at 4, 6; Silver Spring at 2, 4; SMUD, PTR at 56; Southern Company Services, Inc. (Southern) at 3-4; Tendril at 3-4; TIA at 3; United States Telecom Association (US Telecom) at 1-3; UTC at 6-7, 10-11; Verizon and Verizon Wireless (Verizon) at 1-3; Whirlpool at 2-3; Xcel Energy (Xcel) at 4-5; Xcel Reply at 4-5.

[17] *See, e.g.,* Cisco Systems (Cisco), PTR at 15-16; SDG&E at 11-12; APPA at 11; DRSG at 6; CEA at 5; EEI at 23-24; FPL at 7-8; Idaho Power at 7; Tendril, PTR at 44-45.

[18] Cleco at 3; Oncor at 4.

[19] Tendril, PTR at 21-22. Most, but not all, commenters agreed that consumers should not be allowed to "opt out" and disallow a utility from using their personal energy-usage data for planning or network management. These commenters raise valid concerns about the potentially deleterious effects that the resulting incomplete data sets could have upon planning or network management activities required to ensure the reliability and adequacy of our electrical generation and transmission system. *See, e.g.,* Oncor at 3-4; Pepco at 2; EEI at 15-16; DRSG at 3. *But see* CPower at 2; Joint Consumer Comment at 5.

Consumers should be able to access CEUD and decide whether third-parties are entitled to access CEUD for purposes other than providing electrical power.

There is almost universal consensus on the question of consumer access to their CEUD, though some parties disagree about whether the right that customers have to CEUD should be described as a right of access or ownership. Many commenters assert that customers have ownership rights in their own CEUD.[20] Many others assert that those rights are more accurately described as access rights.[21] When discussing the privacy implications of Smart Grid technologies, the difference between these two positions is not entirely semantic, but it need not be dispositive.[22] While the nature of the CEUD provided to a given consumer may vary somewhat, depending upon which technologies are employed and how they are implemented, there seems to be broad consensus that providing consumers with access to "actionable" data, CEUD that they can use to alter their energy-use patterns to reduce their overall energy costs, should be a critical goal of any implementation of Smart Grid technologies like advanced metering.[23] Indeed, the long-term national benefits of such technologies depend significantly upon meaningful access to such data.

There also seems to be a broad consensus on perhaps the most critical question in the context of Smart Grid technologies: who should control the extent to which third parties should be able to access CEUD for innovative purposes other than the provision of electrical power? On this question, almost all proponents of both consumer-ownership rights and consumer-access rights agree: Consumers should decide whether and for what purposes any third-party should be authorized to access or receive CEUD. Consumer control of third-party access to CEUD would promote the development of a competitive, open, transparent, and innovating marketplace for the use and management of energy-consumption data.[24] Most advanced smart meter technologies would provide consumers with data (through in-home displays or other devices) that could be used to reduce energy costs by managing their energy use or using automated means of doing so.

[20] *See, e.g.,* CEA at 2; Elster at 1; EnerNOC at 2; Honeywell at 1; NASUCA at 7, 16 (arguing that the consumer pays for the infrastructure by which the utility obtains access to the data, which can reveal personal information about the consumer); NASUCA Reply at 2-5; SDG&E at 3; Sawnee, PTR at 40; Whirlpool at 2.

[21] EEI at 4-5 ("Ownership of energy consumption data is a complex question that extends beyond a simplistic notion of 'ownership,' and pertains more to issues of data access and usage."); *see also* BG&E at 2; FPL at 3; Idaho Power at 4; NRECA at 3; Oncor at 2 (while noting that under Texas law, consumers served by investor-owned utilities own their energy consumption data); Pepco at 1; Southern at 3; Tendril at 2-3; UTC at 3-6.

[22] Utilities may be correct to assert that the rights that consumers have in their CEUD might most accurately be described as rights of access and control. *See, e.g.,* EEI at 4-5. But the particular term used to describe the rights that consumers have as to their own CEUD may not matter provided that the rights that consumers have as to CEUD do not impede utilities from using CEUD for purposes associated with the provision of electrical power, or the management of the generation, transmission, and billing processes. Indeed, enhancing the ability of utilities to manage, plan, and troubleshoot are among the most important advantages of Smart Grid technologies. And as many commenters noted, utilities have long collected, used, and protected potentially sensitive data about their customers. *See, e.g.,* FPL at 3; Idaho Power at 4-5; APPA at 16-17; NRECA at 17-19. The data privacy concerns associated with Smart Grid are not new, though as discussed above, the more detailed data potentially provided by Smart Grid technologies may warrant review to ensure the adequacy of existing laws, standards, and practices related to utilities' management of CEUD.

[23] Google at 1.

[24] *See* http://www.smartgrid.gov/sites/default/files/pdfs/wh_response_letter_4aug2010_to_climategroup_and_consumer_groups_on_sg_data.pdf "We believe that providing consumers with clear, timely, and appropriate information about their energy consumption and electricity pricing is critical to optimizing the efficiency of the electric grid and facilitating our Nation's transition to a clean energy economy."

Nevertheless, many commenters argued that third parties may well use data generated by such meters to provide consumers with far more innovative or sophisticated energy-management or other services. There seems to be broad consensus that empowering consumers to authorize disclosure of their CEUD to third-party service providers will promote innovation.[25]

There was less consensus on the closely related, but distinct, question of whether utilities or other third-party service providers should be allowed to reduce the costs of their services by disclosing or reselling CEUD to third parties for purposes of targeting advertising. While there appears to be widespread agreement that such practices, if permitted, should require further affirmative and informed consumer consent, one jurisdiction requires at least utilities to obtain regulatory approval before disclosing any potentially sensitive data.[26]

All classes of electric utility customers should be entitled to protect the privacy of their own individual energy-usage data.

This proceeding focused on the issue of *residential* consumer data-security and privacy. Participants frequently noted, however, that the deployment of Smart-Grid technologies also has important implications for other classes of utility customers. Commenters stated that all classes of electric utility customers besides residential consumers (e.g., industrial, commercial, small business, and non-profit customers) are also users of electrical power and customers of an electrical utility. As a result, such customers are similarly entitled to privacy protections for their individual-specific electric usage data.

In particular, many commentators agreed that for many of the same reasons that consumer energy-usage data should be treated as CEUD, commercial or organizational customers of utilities should also be entitled to protect the privacy of their energy-usage data. Just as detailed energy-usage data could be used to generate information about household activities that many consumers might consider personal or sensitive, so too could such data be used to discern information about commercial or organizational activities that many of these entities might consider to be proprietary or highly commercially sensitive. Consequently, many commentators stressed that well-designed regulations or deployments of Smart Grid technologies should carefully consider the implications of these technologies for commercial and organizational utility customers, as well as consumers.[27]

Beyond this point, the relationship between commercial and organizational customers and Smart Grid technologies raises complex questions that exceed the intended scope of this proceeding and as to which no clear consensus positions seemed to exist.[28] Should further information on such matters prove helpful, DOE would consider conducting further study on these issues and

[25] *See, e.g.,* Google at 1; Cisco, PTR at 68-69; Silver Spring at 6; Tendril, PTR at 75-76; Sawnee, PTR at 104-105. *But see* http://www.ftc.gov/bc/international/docs/smartgrids_usa.pdf.
[26] *See,*Cleco at 2; *See also, e.g.,* Avista at 4; EEI at 8-9; FPL at 3; Idaho Power at 4; NASUCA at 29-30; Pepco at 1, 11-13; SDG&E at 3.
[27] *See, e.g.,* Avista at 1; EEI at 9; EEI Reply at 6-7; NRECA at 7; SDG&E at 4.
[28] *See, e.g.,* Building Owners and Managers Association (BOMA) at 2; Real Estate Roundtable (Roundtable) at 3-5.

providing the results of such studies and any further information gathering in its role as an information "clearinghouse", as discussed in more detail later in the Report.

Deployment strategies must be flexible for utilities serving rural, low-income, minority or elderly customers, and consider the special circumstances of those customers, but should not presume that Smart Grid technologies are inappropriate or unhelpful to such customers.

Commenters addressing the issue consistently stressed that efforts to deploy Smart Grid technologies should be flexible and consider the special circumstances of rural, low-income, minority, and elderly electric utility customers. Nevertheless, commenters did not always agree about the implications of these technologies for these important constituencies. Some worried that advanced metering is likely to be more of a cost than a benefit to such constituencies because they are less likely to understand its implications, and have access to resources, like broadband Internet access, or lack the financial resources required to exploit them.[29]

Commenters like the Joint Center for Political and Economic Studies stressed that overall strategies toward the Smart Grid should consider the unique circumstances of rural, low-income, minority, and elderly electric utility customers precisely because these constituencies "are most susceptible to high energy costs" and therefore can most benefit from savings in those costs.[30] The National Rural Electrical Cooperative Association notes that non-profit rural cooperatives have been early adopters of technologies like AMI because they "provide real benefits to [low-density populations] including lower distribution costs and fewer and shorter outages."[31] The Institute for Electric Efficiency has also released a whitepaper discussing several pilot programs that show low-income consumers can and do benefit from the dynamic pricing that Smart Grid technologies enable.[32] That said, DOE recognizes that the relevant costs and benefits of different Smart Grid technologies will be borne out over time as experiments with different approaches realize different results. These results will reflect an array of factors, such as the specific technologies in question, the relative effectiveness of consumer education as to how to use the technology, and the ability to cohere with consumer behavior (e.g., employ "set-and-forget" defaults to limit the demands on consumer to monitor real-time energy use).

[29] APPA at 8-9; Joint Center at 9-10 (noting that further study was needed to determine the impact of Smart Grid on these consumers).
[30] *See* Joint Center at 1; *see also* Google OSTP Comments at 2 (arguing that low-income customers are particularly price-sensitive and that "studies indicate the access to direct feedback on energy consumption leads to energy and money savings"); Google FCC comments at 4-5 (citing studies and discussing the "Prius effect" in which near-real-time data on energy consumption encourages energy-conserving behaviors).
[31] NRECA, at 2 (citing F.E.R.C. Ann. Rep. on the Assessment of Demand Response and Advanced Metering 8 (Dec. 2008), *available at:* http://www.ferc.gov/legal/staff-reports/12-08-demand-response.pdf.)
[32] *See* IEE, *The Impact of Dynamic Pricing on Low Income Consumers* (June 2010) (concluding "that low income customers will benefit from dynamic pricing"). *But see* "The Need for Essential Consumer Protections" (August 2010), issued by a group of consumer entities raising questions about the methodology and findings contained in the IEE report.

Consequently, deployment of Smart Grid technologies should not presume that low-income, minority, and elderly constituents will be harmed by, or should be excluded from, the Smart Grid. Rather, deployment strategies should be crafted to identify and serve the needs of these important constituencies.[33] For example, the Public Utility Commission of Texas has approved both consumer-education efforts related to Smart-Grid and the funding of a program that will provide low-income consumers with free in-home monitors to help them monitor their energy uses. Texas and other jurisdictions have also authorized the use of prepayment plans that have proven to be popular with low-income consumers. Under such plans, consumers purchase a given dollar-value of power, and an in-home monitor that interoperates with a smart meter reports both their energy usage and the amount of money left in the account.[34]

States must carefully consider the conditions under which consumers can authorize third-party access to CEUD.

The issue of third-party access is complex and fairly contentious, but may be somewhat narrower than it sounds. If consumers can access or own their CEUD, then once that data has been provided to them, consumers could ordinarily keep it private or disclose it to whomever they choose. Indeed, more advanced smart-meter technologies may soon make it much easier for consumers to provide at least some types of CEUD directly to third parties. Such meters can interconnect through a home-area network ("HAN") with interoperable devices using secure protocols.[35] It should be noted that easy transferability of CEUD should be considered as such technologies are developed. Transition to the use of standardized, machine-readable formats is discussed in more detail later in this report.[36]

Nevertheless, in some contexts, more granular CEUD may be more useful to consumers if they can authorize their utilities to disclose it directly, and on an ongoing basis, to a third-party service provider selected by the consumer. Consequently, the issue of third-party access focuses on whether or how states should regulate the process through which a consumers can grant (and

---

[33] *See* comments of the Joint Center; Exelon at 3; NASUCA at 18-19; Pepco at 3-4; UTC at 11-12 (citing the IEE whitepaper).
[34] *See, e.g.,* Oncor at 4, 6.
[35] *See, e.g.,* Oncor at 9 (noting that for security purposes, consumers must use a utility's provisioning process in order to ensure that only devices approved by them are associated with their meter); *see also* SCE Reply at 1 (discussing the interaction of HANs, advanced meters, and interoperable devices); EEI at 9 (advocating privacy protections for "more general consumer information that may be generated, not only by smart meters, but also by [HANs] and devices connected directly for third party access"); Google OSTP Comments at 1 (noting "multiple gateways for residential energy use data, price data, and demand response signals").
[36] DOE understands that NIST has initiated efforts to support standardization of energy usage information with a North American Energy Standards Board (NAESB) standard information model for customer energy usage information and an American Society of Heating, Refrigerating and Air-Conditioning information model for facility energy usage. In addition, other standards supporting implementation of these information models are already under development, including Open ADE (with NAESB) and the Zigbee Smart Energy Profile 2.0. DOE notes that once any protocols or model standards are developed and published by NIST for the interoperability of Smart Grid devices and technologies, an investment that fails to incorporate any of such protocols or model standards is not eligible for reimbursement under the Federal Smart Grid Investment Matching Grant Program. Pub. L. 110-140, Section 1306.

retract) authorization for a utility to disclose CEUD to a third-party service provider selected by the consumer.

Commenters certainly agreed that this is one of the most important and difficult issues inherent in deploying and regulating Smart Grid technologies. This question of how consumers authorize utilities to disclose CEUD to third parties thus raises difficult questions on which there seems to be fairly broad consensus on some core principles, but less agreement on how best to implement those principles. In general, there seems to be substantial consensus on the following principles:

***First,* Utilities should not disclose CEUD to third parties unless a given consumer has consented to such disclosure affirmatively, through an opt-in process that reflects and records the consumer's informed consent.** Often, the use of such an opt-in authorization process will have to comply with existing laws that prohibit utilities from disclosing customer data to third parties without a particular customer's informed consent. In any case, commenters were virtually unanimous that an opt-in authorization process predicated on informed consent should be required before utilities disclose CEUD to third-party service providers.[37]

***Second,* jurisdictions designing such opt-in authorization processes should require a valid authorization that specifies the purposes for which the third-party is authorized to use CEUD, defines the term during which the authorization will remain valid and identifies the means through which consumers can withdraw such authorizations.** Commenters tended to stress, in particular, that the informed consumer consent required by an opt-in process should require a valid authorization to identify both the type of CEUD that the third party seeks to obtain and the purposes for which that third party is authorized to use the CEUD. Here again, many commenters stressed the importance of full and clear disclosure if the third party intends to use CEUD for purposes of targeting advertising or marketing towards the consumer.[38] Such disclosure requirements and the ability to opt-in to Smart Grid data sharing must be clearly communicated to consumers as part of any Smart Grid education effort.

***Third,* third parties authorized to receive CEUD should be required to protect the privacy and the security (including integrity and confidentiality) of CEUD that they receive and to use it only for the purposes specified in the authorization.** Some commenters asserted that third-parties should be required to comply with all legal requirements related to the protection of CEUD that are applicable to utilities. Others proposed more general legal duties.[39] Nevertheless, there was broad consensus that authorized third parties should be required to

[37] *See, e.g.,* DTE, PTR at 86; EEI at 17, 23-24; Honeywell at 3; NASUCA at 16; NW Energy, PTR at 41; Oncor at 4-5; Pepco at 6; Southern at 4; Tendril , PTR at 36, 43; TIA at 3.

[38] *See, e.g.,* APPA at 6; Silver Spring at 3; Xcel at 3, 7-8; Xcel Reply at 7. A number of commenters also supported the Fair Information Principles developed by the Federal Trade Commission (FTC FIPPs) and other similar practices that include identification of the types of CEUD sought and the uses to which the CEUD will be put, as well as the identity of the entity collecting the data and any potential recipients of the data. *See, e.g.,* CEA at 3; DRSG at 2, 4; EnerNOC at 4; NASUCA Reply at 7-8; Pepco at 4; TIA at 3; Tendril at 3-4; SCE at 1, 4; Xcel at 6.

[39] *See, e.g.,* EEI at 14, 30; Elster at 4; Exelon at 3-4; Oncor at 8; SMUD, PTR at 64-65; Tendril, PTR at 42; US Telecom at 2 (all supporting applicability of the same standards to which utilities are held). *See also* Cisco, PTR at 68-69 (noting that standards for third party handling of data are still an open question and that not any one system is necessarily the right one).

protect the privacy and security of CEUD and use it only for the purposes specified in the authorization.

***Fourth*, States should enact laws or rules that define the circumstances, conditions, and data that utilities should disclose to third parties.** For different reasons, both third-party service providers and utilities expressed concerns about the implications of systems in which utilities determine whether or when potential competitors will be granted access to CEUD.[40] Nevertheless, States defining such terms may wish to consider defining the set of data that utilities must disclose without precluding utilities from agreeing to disclose other data to authorized third-party service providers. Such flexibility may be needed because it now seems difficult to predict whether and to what extent security and cost considerations will tend to make utilities or consumers (empowered by Smart Grid technologies) the long-term, low-cost providers of useful, secure access to any given class of CEUD.

There are, however, many more issues relevant to third-party authorization as to which there is no clear consensus among jurisdictions or commenters. As to these issues, there is consensus that certain questions need to be addressed when Smart Grid technologies are deployed, but divergent opinions as to what the best answers to those questions are, and the extent to which the best answer may differ from jurisdiction to jurisdiction. Consequently, in these areas, it is appropriate to note the most important questions, identify varying approaches to them, and assess the record for evidence of trends or potentially superior solutions.

How should consumers authorize third-party access to CEUD? Texas currently requires consumers to submit a written letter of authorization.[41] Third-party service providers like Oncor argue, however, that it would be more efficient to let consumers authorize third-party access online, through a secure web portal.[42]

An online authorization process is currently in use in California.[43] While California law also requires written authorization, such authorization is construed to encompass electronic authorization for purposes of SDG&E's protocol that allows a customer to authorize, using SDG&E's "My Account" webpage, transmission of that customer's usage data to third parties. Once a customer provides authorization, SDG&E assigns a unique identifier to the customer and his or her usage data to facilitate the transfer of that data to authorized third parties. SDG&E established this protocol in response to the recent CPUC requirement that investor-owned

[40] *Compare* Tendril at 7-8 (noting that "customers should be free to choose from services available from an open and transparent marketplace"), *with* EEI at 10-11; EEI Reply at 18 (noting that "unfettered third party access is insufficient and overlooks important state-based consumer protections, as well as the need for third party verification") and National Association of Regulatory Utility Commissioners (NARUC) at 1 (noting its 2009 resolution calling for, among other things, policies and standards that "should promote a flexible, non-proprietary, open infrastructure," and "encourage interoperability of the electric grid and information services to foster a vast array of resources and information services."
[41] Oncor at 4-5, 11.
[42] Oncor at 4-5, 11.
[43] SDG&E at 15-16.

electric utilities provide third parties with access, upon the customer's consent, to that customer's real-time or near real-time usage information by the end of 2011.[44]

An online authorization process raises additional security concerns, and would require strong authentication protections to ensure that any person purporting to authorize access was actually the consumer who had the legal authority to grant such access. Nevertheless, DOE recognizes the obvious efficiencies of an online process and the expanding range of sensitive e-commerce and other transactions strongly suggest the long-term advantages of online authorization processes. Consequently, States could consider transitioning towards an online authorization process, such as the process currently being studied in Texas.[45]

When and how should jurisdictions limit the potential legal liability of utilities required to disclose CEUD to consumers or authorized third parties? In many jurisdictions, electric utilities have legal duties and existing policies that require them to protect the confidentiality and security of CEUD that they collect, possess or use. Obviously, when utilities are required to transfer CEUD to consumers or authorized third-party service providers, they cannot, as a practical matter, continue to protect that transferred data's confidentiality and security. Utilities thus argue that they should not be legally liable for CEUD that has been disclosed to an authorized third-party provider: "[A]uthorized third parties must be responsible for protecting that data and liable for any unauthorized access or intellectual property infringement that may occur."[46]

This is an important issue. Third-party service providers, not utilities, should assume legal responsibility for protecting the security and privacy of CEUD that utilities disclose pursuant to a consumer authorization. Nevertheless, relevant state and local laws vary, and consequently, there may be no one approach to defining the bounds of legal liability for CEUD that works for all jurisdictions. For example, in some jurisdictions, tarrifing regulations and practices may provide a means to define the bounds of a utility's liability, but not those of authorized third-party service providers.[47]

How should consumers be educated about which complaint procedures apply when third-party access to CEUD has been authorized? Many states authorize Public Utility Commissions, ("PUCs"), to receive and adjudicate consumer complaints about investor-owned electric utilities. But state PUCs generally have jurisdiction over investor-owned electric utilities—not third-party service providers authorized to receive CEUD, who may now be regulated only by more general laws, like state consumer-protection laws often administered by a state's Attorney General. Consequently, jurisdictions deploying Smart-Grid technologies will have to carefully consider both the adequacy of existing remedial processes and how to ensure that consumers understand whether to direct concerns or complaints to a PUC or to other

[44] Id. SDG&E also discusses its Customer Energy Network, an application that allows SDG&E customers to view their energy use data through authorized Internet content-providers.
[45] Oncor at 4-5, 11 (noting that the Public Utility Commission of Texas is now studying online authorization). Commenters also recognized that Smart Grid technologies could borrow security architectures used in other industries, such as online banking, internet shopping, and wireless communications to ensure the authenticity of such authorizations, as well as the protection of consumer data, *See, e.g.*, DRSG at 7; EnerNOC at 5; Tendril at 6.
[46] EEI at 14.
[47] *See* Xcel at 4; *See also* NRECA at 11-12.

officials. At least two commenters suggested that independent ombudsman services might provide a means to minimize potential consumer confusion.[48]

What data should utilities have to disclose to authorized third parties? Most commenters agreed that utilities should be required to disclose to authorized third parties at least data used in billing, and some retail energy-price data. Most commenters also supported disclosure of raw meter data, though some voiced concern over consumer confusion that could result if raw data differed from data validated by the utility and used in billing.[49] Nevertheless, the set of data thus defined may vary depending upon what data a given metering technology provides, and how a given customer is charged for energy used. As a result, Google may have best summarized the consensus position when it argued that "consumers should have access to timely, useful, and actionable information about how much energy is used, and what it costs."[50]

Beyond that, there was little consensus about what, if any, other types of energy-usage and price data utilities ought to be required to collect and disclose to customers and authorized third-party service providers. Some commenters favored very broad data-collection-and-disclosure requirements.[51] Utilities, however, tended to stress that jurisdictions need the flexibility to balance the inarguable costs of imposing particularly broad or highly granular data-collection-and-disclosure obligations upon utilities against the potential benefits of narrower and less expensive collection and disclosure obligations.[52]

Moreover, no clear patterns or trends have yet emerged from existing disclosure practices. For example, California has promulgated a regulation prescribing relatively detailed and extensive data-disclosure obligations.[53] Texas has taken a somewhat different approach that requires consumers to be able to access their meter's 15-minute interval data for the previous day and historic data through a common web portal called the Smart Meter Texas Portal.[54] DTE advocates the use of pilot programs to generate data that will help jurisdictions assess the relative costs and advantages of various disclosure requirements and the extent to which they promote desired changes in conservation and consumption behaviors.[55]

---

[48] *See, e.g.,* Tendril at 4; CPower at 2.
[49] *See, e.g.,* DRSG at 9-10; Elster at 4; EnerNOC at 6-7 (all supporting the provision of raw data). *But see* EEI at 33-36 and EEI Reply at 25 (raising concerns over consumer confusion if raw data, as opposed to verified data, is provided). *See also* NRECA at 14-16.
[50] Google at 1.
[51] *See, e.g.,* CEA at 7 (asserting that there should be no artificial caps on the amount or type of information that consumers could request from a utility); NASUCA at 26-28; Tendril at 8-9.
[52] APPA at 14-15; EEI at 35-36 and EEI Reply at 22-24; NRECA at 14-16.
[53] See SDG&E at 17 ("With respect to the protection of customers' privacy interests, the California Commission has continued longstanding California policies requiring the utilities to protect a customer's energy information, allowing disclosures only with the prior written consent of the customer. [A]ccess to that information, where authorized by the customer, must be provided to third parties via the Internet, and in real-time or near-real-time by the end of 2011" (citing *Rulemaking to Consider Smart Grid Technologies Pursuant to Federal Legislation and on the Commission's Own Motion to Actively Guide Policy in California's Development of a Smart Grid System,* Decision 09-12-046 in Docket R.08-12-009, at pp.51, 65, 78).
[54] Oncor at 2.
[55] DTE at 6.

While comments and public discussions revealed only a narrow and general consensus on some aspects of this question, analysis of the principal points of disagreement among the interested parties identifies four particularly important issues that jurisdictions should assess when crafting disclosure obligations.[56]

First, commenters often disagreed about the extent to which utilities should have to collect and provide highly granular or near-real-time consumption or pricing data. Utilities often observed that even when advanced meters actually supply consumers with near-real-time energy-usage data, the costs that utilities would incur were they forced to collect and manage such data might exceed any conceivable benefits to consumers, utilities, or the management of the electrical generation and transmission system.[57] The example of Southern California Edison, cited below, serves to clarify some of the issues surrounding near-real-time data.

Second, commenters disagreed about whether or to what extent utilities should have to provide *historical* energy-usage data (other than the data already provided for billing purposes) to consumers and third-party service providers.

Third, utilities strongly objected to claims that they should be required to disclose to third-party service providers any CEUD-containing data other than that used in billing a particular customer, once that data has been validated, enhanced or aggregated by the utility for its own business, network management, or regulatory purposes.

Fourth, commenters disagreed about the extent to which utilities should be required to disclose data in standardized, machine-readable formats. Device producers and third-party service providers argue that CEUD should be provided in standardized, machine-readable formats.[58]

DOE concludes that these disputes reveal some important, if unresolved, policy questions that States should carefully consider. On the one hand, very broad data-disclosure requirements could facilitate the development of a broader range of Smart-Grid-based third-party business models. But on the other, broad requirements could distort and increase the apparent costs of electric power by requiring utilities to collect and provide data not needed to provide electrical

---

[56] It may be important to note that potential providers of third-party services often did not make it entirely clear whether they were advocating that certain data should be available from either the consumer or the utility, or from the utility itself. The difference between these two sourcing options can be significant. *See* SCE Reply at 1-2 (noting that third-parties can obtain near-real-time energy-usage data by providing consumers with a device that can interoperate with its customers' smart meters, but that SCE itself does not backhaul and collect near-real-time usage data).

[57] EEI Reply at 22-24 ("EEI believes that calls for access to such data in real, or close to real time do not take account of the costs involved, or the limited benefit to consumers. The cost can be substantial. The cost for providing this level of granularity is disproportionate to the benefits"); NRECA at 17 (noting the usefulness of data provided at intervals other than real-time); UTC at 17-18 ("Converting [the process of transmitting data] into a 'real-time or near real-time' process would require major overhaul of the utility infrastructure that would seriously undermine any value created with potentially significant cost implications."); *but see* Tendril at 9 (noting that certain energy consumption data is "likely to fluctuate in real-time and therefore must be presented to the consumer in order to be actionable"); CEA at 7 (noting that broad availability of real-time energy data "will lead to the development of products and services that are beneficial to consumers and empower them to make informed decisions regarding their energy consumption.").

[58] CEA at 6; *but see* EEI Reply at 19.

utility services. Consequently, such debates should be carefully assessed by State and local officials in light of local conditions.

The case of Southern California Edison (SCE) shows why there is no clear, all-purpose argument for imposing more demanding access requirements. SCE's smart meter program uses meters that can provide raw near-real-time energy usage data that can be accessed not only by the consumer, but also by interoperable devices implementing an appropriate security protocol over a HAN. But SCE itself does not collect that real-time data: Instead, it backhauls usage data from meters at hourly intervals. This data is then validated and processed to produce the "revenue quality interval usage data" that SCE uses for billing and providing utility services, and provides to consumers on a next-day basis through SCE's web portal.[59] Therefore, although SCE's smart meters do provide near-real-time data to consumers, SCE warns that it would need to re-engineer its smart-meter system were *SCE itself* required to provide third parties with near-real-time energy-usage data, or "revenue-quality" interval-usage data on other than a next-day basis.[60] SCE makes similar points about the expense of any requirement that would require it to provide near-real-time retail-price data, when the needs of customers exploiting the retail-pricing options available in its jurisdiction can be adequately met by day-ahead retail price signals.[61] Moreover, it is far from clear that real-time access (in the minute-by-minute sense) is necessary to enable many (or even possibly most) of the benefits from a Smart Grid architecture.[62]

This example illustrates a potentially critical point. Utilities can promote the innovation that Smart Grid technologies enable by serving as least-cost providers of a potentially vast array of data including current and historic CEUD that they actually collect and maintain. But to the extent that utilities are required to collect or retain data exceeding that required to provide efficient electric power generation, transmission and delivery services to their particular customers without charging for such access, this requirement threatens to distort the cost of electric power vis a vis that of third-party services.[63] To similar effect, when utilities pursue their own business purposes by expending resources in order to backhaul and "enhance" raw CEUD already provided to consumers beyond what is necessary for billing, similar issues could arise if utilities were required to disclose that "enhanced" data to third parties at no additional cost.

Nevertheless, States should encourage transition towards standardized, machine-readable formats for transferring CEUD to authorized third parties. In particular cases, utilities may have valid arguments for continuing to use legacy formats during an appropriate transition period. After any such transition, however, the benefits of standardized, machine-readable formats are

[59] SCE Reply at 1.
[60] SCE Reply at 2.
[61] SCE Reply at 2-3.
[62] This issue is why some suggest it is open question whether the installation of new advanced metering infrastructure is necessarily a more cost-effective strategy than the use of existing automated meter reading technology. The NSTC Subcommittee is evaluating the merits of this "smart enough grid" analysis through an RFI recently issued by DOE's Office of Electricity Delivery and Energy Reliability (75 FR 57006, Sept. 17, 2010).
[63] *See, e.g.,* EEI Reply at 22-24. But note that a similar concern could also arise if charges or requirements imposed upon third-party access provided a means through which excessive fees or restrictions could be imposed upon would-be-rivals, thus potentially undermining full and fair competition in the market for electric usage monitoring services.

significant. DOE thus concludes that given the compelling advantages of machine-readable formats, State laws should be designed to ensure a prompt transition toward machine-readable formats that provide for very low-cost access.

In summary, States regulating the deployment of advanced metering technologies will have to resolve debates about the extent to which utilities should be required to disclose to third parties data exceeding (1) the “raw” data actually collected in order to provide services efficiently, (2) any verified data actually used in billing a given customer, (3) “actionable” energy-price data, and (4) any other data as to which there is broad agreement that utilities should provide when authorized by a consumer.

When resolving these important debates about the extent to which they should require utilities to disclose additional data, States should consider, in addition to the factors noted above, three core principles grounded in sound competition policy. First, to the extent that utilities are *required* to disclose data that is either reasonably available from consumers, in excess of that required to provide optimal electric-utility services, or utility-“enhanced” data not used in billing, a cross-subsidy may occur—at least if utilities cannot charge fees for third-party access to such data. *Second*, States confronting the highly contested issue of letting utilities charge for third-party access to CEUD should carefully consider two sets of concerns: On the one hand, if utilities cannot recover costs incurred to provide third-party access to CEUD this could distort the costs of providing electrical power; on the other hand, if utilities can impose unnecessary charges or undue requirements related to accessing such data, that could distort or otherwise undermine competition in the adjacent market of managing the use of electric power.[64] *Third*, because it is not clear whether consumers or utilities will be identified as the long-term lowest-cost provider of any given type of additional data, States should consider designing disclosure obligations in a competitively neutral manner. In particular, they might seek to ensure that relevant laws or regulations do not define the data that utilities are required to disclose to consumer-authorized third-party service providers in an unduly narrow manner so as to limit that range of entities that could operate effectively as consumer-authorized third-party service providers.

DOE notes that further analysis of the debates about the costs and benefits of access to real-time or near-real-time data is being conducted by the Office of Science & Technology Policy of the Executive Office of the President. It is also worth noting that providing consumers with near-real-time access to usage data through a route that does not involve the utility is highly consequential from a privacy perspective. If consumers receive this data through a route that is entirely local, e.g., via a HAN gateway that connects to an in-home display or other in-home device, then it may be the case that neither a utility nor a third party will have access to this data. On the other hand, if other means of sending near-real-time data (e.g., transmitting data over a home Internet connection or cell phone) are under consideration, then third parties are in the picture, and as discussed above, the attending privacy issues require careful consideration.

Can utilities charge a fee for providing third-party access to CEUD? Commenters disagreed about whether utilities should be able to charge a fee—either cost-based or costs-plus-return—before disclosing CEUD to authorized third parties. Predictably, utilities and potential third-

[64] For a discussion of this concern, see http://www.ftc.gov/bc/international/docs/smartgrids_usa.pdf.

party users of CEUD disagree on this point, and both raised valid policy concerns. Potential third-party users of CEUD argue that if utilities are required to provide CEUD to their customers without further charges, then the same principle should apply when customers authorize a third party to act on their behalf. Utilities argue that processing third-party authorizations and providing data imposes costs in excess of those associated with providing electric power, and that these costs should be borne by third-parties seeking access to such data for their own business purposes.[65]

At the end of the day, the relevant question may be this: Is it more appropriate to spread the costs associated with providing third-party access to CEUD among all utility customers, or only among those customers who authorize third-party access to CEUD?[66] Jurisdictions reaching the former conclusion may encourage the development of third-party services, because the cost is spread over all consumers. Jurisdictions reaching the latter conclusion may keep electricity rates slightly lower for all customers (by imposing the costs of available CEUD-based services only on those customer who use such services), but only if the costs imposed on those seeking access to CEUD are caused by making such CEUD available, Sound economics and public policy suggest that an entity causing particular costs should pay for those costs so that these entities do not demand the good without appreciating its true cost. At the same time, there should be no artificial barriers imposed on other firms that wish to gain access to that information and use it for other purposes. Thus, States should be alert to the risk that overestimates of such costs could distort competition in the market for third party electricity management services.

Should authorized third-party service providers be required to obtain further informed consent before disclosing CEUD or CEUD-generated customer data, particularly for purposes of marketing? Many states prohibit utilities from sharing or selling CEUD or other customer-identifying data to third parties. For example, Washington state law prohibits a utility from disclosing or selling private consumer information to affiliates, subsidiaries or third parties for the purpose of marketing services or products to customers not already subscribing to them without first obtaining the customer's written consent to the disclosure.[67] Many commenters identified this as an area of particular concern to consumers.[68]

Should states and localities impose some sort of "certification" requirement upon third-party service providers that wish to be authorized to receive CEUD? If third-party service providers must use CEUD only for authorized purposes, maintain its security, and assume liability for its improper disclosure or use, then questions arise as to whether jurisdictions should impose requirements that would help consumers and utilities determine whether providers

---

[65] *See, e.g.,* EEI at 5 ("Parties who undertake the risk of providing capital necessary to capture and manage energy usage data should have rights to the economic value of that data.") and 30 ("The mechanisms for the delivery of CEUD to third parties may involve costs that should not be borne by utilities."). *But see* BOMA at 3; Google OSTP comments, at 2 (noting that authorized third parties, along with customers, should not have to pay extra for to access consumption data).
[66] *See, e.g.*, EEI Reply at 24 (arguing that all utility customers should not be required to cross-subsidize the use of third-party services).
[67] *See* Avista at 4.
[68] NW Energy, PTR at 13-14; EEI at 9; SMUD, PTR at 14-15, CO OCC, PTR at 11-13.

claiming to have these capabilities actually do.[69] In somewhat analogous contexts, states have used diverse means to provide such signals or assurances. Such means may include registration, licensing, bonding, or approval by one or more third-party certifying bodies. For purposes of further discussion, we will collectively refer to these examples of an even wider array of legal options as "certification requirements."

Many participants addressed the issue of whether some certification requirement should be imposed upon third-party service providers, but their views on it often differed substantially. Utilities generally favored the extra certainty that such requirements conferred upon them and their customers. Providers of third-party services generally opposed any requirements that threatened to become significant barriers to entry and competition.

All sides in this debate raise valid concerns. "Opt in" systems for demonstrating consumer consent certainly can be and have been misused, and such misuses could increase if jurisdictions begin authorizing the on-line opt-in processes favored by third-party service providers.

Given the use of certification requirements in analogous contexts, this appears to be a critical area in which proactive coordination efforts among states, localities, utilities, and third-party service providers could generate significant long-term benefits. If certification requirements become widespread and needlessly diverse, third-party service providers and would face serious barriers to entry and competition that could arise from a maze of certification requirements that could vary not only from state to state, but from locality to locality.[70]

Consequently, federal policymakers may wish to carefully monitor the evolution of the law in this area to ensure that certification requirements do not become *needlessly* divergent and localized. Proactive measures such as coordinating overall approaches, or developing a standard or relatively consistent application processes or certification criteria could significantly reduce paperwork and regulatory burdens that certification requirements might impose upon third-party providers of energy-management services. To that end, this is a promising area for federal-state cooperation as part of broader partnership efforts with the National Association of Regulatory Utility Commissioners and others to advance Smart Grid policy.[71]

[69] *See, e.g.,* EEI at 10-11 (advocating mandatory state certification processes to ensure that entities authorized to receive CEUD have implemented appropriate safeguards and monitoring and compliance programs and have the financial, technical, and managerial resources to continue doing so); NASUCA at 24 (same).
[70] EEI at 11 ("Customers and electric utilities would benefit from a consistent method for state-certified third parties to prove the validity of their state authorizations.")
[71] With regard to technical certification, DOE understands that within the NIST SGIP, the Smart Grid Testing and Certification Committee (SGTCC) members have reached agreement on the foundational elements to be established for Smart Grid technology and technical standards compliance testing and certification programs. The SGTCC is engaging with industry certification organizations to pilot and refine its approach, which may serve as a model for evaluating privacy compliance when considered as a system. The SGTCC is also expanding its collaboration with the CSWG to integrate security testing within its programs.

To promote further cooperation and dissemination of information about practices relating to the regulation of the privacy and data-protection aspects of smart-grid technologies, a web portal should be created to act as a "clearinghouse" for such data.

As the above summary suggests, the Smart Grid technologies that form an important component of a long-term national energy strategy raise important concerns about privacy and the regulation of entities with access to energy-consumption data—concerns that have historically been regulated primarily at the state or local level. Moreover, there are many reasons why the historical primacy of state and local control may be indispensible to the long-term success of the deployment of Smart Grid technologies.

Nevertheless, the relevant law and the available data relevant to federal, state, and local officials is likely to evolve quickly as the pace of deployment of advanced metering technologies quickens, and the coordinating and information-dissemination functions performed by the federal agencies appear to have been useful means to promote thoughtful assessment of the issues, and avoid duplication of effort or needless inefficiencies.

As commenters noted, a central "clearinghouse" for relevant regulatory data, implementation strategies, and studies would be broadly useful not only to federal, state, and local officials, but also to all private and public entities affected by the privacy and security implications of Smart Grid technologies like advanced metering.

DOE will investigate options for a web-portal that can serve all these parties as a "clearinghouse" for available information about the regulation of the privacy and security implications of Smart Grid technologies. The portal could be created as a sub-site of either SmartGrid.gov (www.smartgrid.gov) or the recently created Smart Grid Information Clearinghouse (www.sgiclearinghouse.org), depending upon a needs assessment. We envision that such a portal will include collections of enacted and proposed state laws, relevant federal and private resources, and analyses of pilot programs or ongoing deployment efforts. The assembly of such a collection is well underway as a result of this proceeding, and by updating it, DOE can help avoid duplication of effort and direct interested parties toward the most relevant information about trends in regulatory practices, and better identify areas in which federal agencies can usefully assist the private parties and public officials who will be indispensible to the overall success of the deployment of Smart Grid technologies that will promote the development of a more efficient, interactive, and robust electrical grid.

SUMMARY OF PUBLIC COMMENTS AND INFORMATION

The National Broadband Plan (the "NBP"), authored by the Federal Communications Commission ("FCC") at the direction of Congress, seeks to ensure that every American has access to broadband capability.[72] The NBP also includes a detailed strategy for achieving affordability and maximizing use of broadband to advance consumer welfare, civic participation, public safety and homeland security, health care delivery, energy independence and efficiency, education, entrepreneurial activity, job creation and economic growth, and other national purposes. As part of this strategy, the NBP sets forth a number of recommendations for Federal agencies, including the Department of Energy ("DOE"). In particular, the Plan recommends that DOE consider consumer data accessibility policies when evaluating Smart Grid grant applications, report on the states' progress toward enacting consumer data accessibility and develop best practices guidance for states.[73] Based on this suggestion and the responses to its RFI, DOE set forth its key findings in the preceding section of this report.

In this section, DOE reviews public comments received that provided support for these key findings for states to consider in developing Smart Grid privacy and data collection policies. In so doing, DOE recognized the significant effort that utilities and state regulatory commissions have and continue to put forth to safeguard the privacy of consumer data, as well as the efforts of other federal agencies in developing guidelines for the protection of such data.

To develop the Recommendations and Observations presented in this report, DOE not only conducted its own research, it also sought and received substantial public input from a wide range of interested parties. DOE first published a request for information ("RFI") in the Federal Register, in which DOE sought comments and information from interested parties on current and potential practices and policies for states, as well as other entities such as municipalities, public power entities, and electric cooperatives, to empower consumers through access to detailed energy information in electronic form. Such information could include real-time information from metering technology, historical consumption data, and pricing and billing information. (75 FR 26203, May 11, 2010). In the RFI, DOE also asked interested parties to report on state efforts to enact Smart Grid privacy and data collection policies; individual utility practices and policies regarding data access and collection; third party access to detailed energy information and the role of the consumer in balancing benefits of access and privacy; and policies and practices that should guide policymakers in determining who can access consumers' energy information and under what conditions. In addition to the request for comment in the RFI, DOE provided an opportunity for the submission of reply comments in order to foster discussion of the issues. As a result of the significant number of comments and amount of information received, DOE extended the period for reply comments. (75 FR 43727, July 22, 2010). To gather

[72] The Plan, developed pursuant to the American Recovery and Reinvestment Act of 2009 (P.L. No. 111-5), was issued on March 16, 2010 and is available at http://www.broadband.gov/plan/.
[73] The Plan also recommends that DOE, in collaboration with the FCC, study the communications requirements of electric utilities to inform federal Smart Grid policy. DOE addresses this recommendation in a companion report, *Informing Federal Smart Grid Policy: The Communications Requirements of Electric Utilities*, available at http://www.gc.energy.gov/1592.htm.

additional data, DOE also published a notice in the Federal Register announcing a public meeting to discuss the issues presented in the RFI. (75 FR 33611, June 14, 2010). The public meeting, held on June 29, 2010, provided another forum in which interested parties could provide comments and information, as well as engage in constructive dialogue with other interested parties.

In its RFI, DOE presented a number of questions on issues of data privacy and the Smart Grid that had been raised in both public and private forums, including DOE's long-standing investment in Smart Grid technology through Smart Grid Investment Grants and Smart Grid Demonstrations projects; the Office of Science and Technology Policy's Smart Grid Forum blog, entitled "Consumer Interface with the Smart Grid"; and the National Broadband Plan. Each of these questions is set forth below, and comments and reply comments provided in response are presented. DOE also sought comment on any other issues of data privacy identified by commenters as related to the Smart Grid. Information received on these additional issues, as well as at the public meeting, is integrated into the discussion below.

REQUEST FOR INFORMATION – QUESTIONS PRESENTED

Question 1: Who owns energy consumption data?

A number of commenters indicated that the central issue, rather than data ownership, was the right to control data access. Other commenters offered three distinct viewpoints on the issue of data ownership. Some argue that the consumer owns the data. Others argue that the utility owns the data. Still others argue that the consumer and the utility co-own the data. Nevertheless, all of the commenters noted the importance of access to energy consumption data, and these differing perspectives seemed to reflect the application of a single underlying principle: Rights of access flow from ownership.

As stated above, a significant number of commenters believed that the issue of access was more critical to a discussion of Smart Grid privacy issues than the issue of data ownership. *See, e.g.,* BG&E at 2. Of these, many stated that an approach to Smart Grid data access based on property rights and ownership interests will be problematic given that ownership varies by jurisdiction and is governed by individual state laws. EEI at 4-5; EEI Reply at 4-6; FPL at 3; Idaho Power at 4; NRECA at 3; Oncor at 2; Pepco at 1; Southern at 3; Tendril at 2-3; UTC at 3-6. Many of these commenters also noted that states and other regulators have historically been able to effectively address privacy regulation of customer data without answering the question of ownership, and utilities have developed their own privacy policies consistent with state law. Within this framework, these commenters agreed that customers should have access to their own customer-specific energy usage data ("CEUD")[74] and be able to share, or allow their utility to share, this data with third parties. In addition, to effectively render services, maintain safety and reliability, and carry out other business purposes, utilities and their service providers should have access to and control over all CEUD, as well as operational data, including aggregated customer

[74] Idaho Power used the term customer-specific energy data, or "CSED". A more detailed discussion on the definitions of different types of data is presented in response to Question 3.

data. Further comments on the issue of data access, including third party access and access by governmental jurisdictions, are provided below.

Other commenters stated that the consumer owns his or her individual energy consumption data. CEA at 2; Joint Consumer Comment at 8; Elster at 1; EnerNOC at 2; Honeywell at 1; NASUCA at 7, 16 (arguing that the consumer pays for the infrastructure by which the utility obtains access to the data, which can reveal personal information about the consumer); NASUCA Reply at 2-5 (arguing that utilities may be authorized users, but consumers own their data); NW Energy, PTR at 40-41; Oncor at 2; SDG&E at 3; Sawnee, PTR at 40; Tendril at 2-3; Whirlpool Corporation ("Whirlpool") at 2. Consumers take the actions that actually generate their individual data, which could reveal significant private information about their energy consumption and related habits. Consumers also provide for the growth and maintenance of the utility's infrastructure through payment of their utility bills. Many of these commenters noted that while the consumer owns detailed consumption data, utilities and their service providers should have access to the data for billing purposes. Utilities also need energy consumption data to provide safe and reliable service and to meet various accountabilities. For example, the data is used in critical infrastructure audits, and more porous data would result in more risk. Energy consumption data is also needed to comply with various state law requirements. In addition, consumers typically ask the utility what the data means and how to interpret the data to bring value to the consumer.

Offering a specialized view of ownership, the Building Owners and Managers Association International ("BOMA") and the Real Estate Roundtable ("Roundtable") clarified that property owners own energy consumption data generated for properties that they own, except where the data is separately metered. In those cases, the individual tenants own the data. BOMA at 1; Roundtable at 3. NASUCA stated that property owners have the right to review aggregate building data to comply with regulatory mandates such as LEED certification and for capital investment purposes, but not individual data unless the customer has provided written permission. NASUCA Reply at 5.

Other commenters asserted that the utility collecting the energy consumption data owns the data. Avista at 1; DTE at 2; Exelon at 2; SCE at 1; Xcel at 3; Xcel Reply at 3. These commenters argued that the utility installs, maintains and operates the infrastructure by which the energy consumption data is generated and thus owns the data. In addition, as stated above, the utilities have a need to access this data for billing, planning and other business purposes. Of these, all but one acknowledged explicitly that consumers should have access to their usage data.

Some commenters argued for a middle-ground approach, under which energy consumption data should be co-owned by the utility and the consumer. APPA at 4-5; CPower at 1; DRSG at 1-2; Silver Spring at 1-2; TIA at 2. A number of these commenters clarified that personally-identifiable, individual data was owned by the consumer, though some believed that such data was also owned by the utility for operational purposes. These commenters agreed that aggregate data was owned by the utility. Some further noted that governmental entities should be co-owners of aggregate data produced within their jurisdiction.

Question 2: Who should be entitled to privacy protections relating to energy information?

Commenters generally agreed that the consumer should be entitled to privacy protections relating to individual consumption data and personally identifiable information. AARP Reply at 4; APPA at 5; Avista at 1; BG&E at 2; Cleco at 1-2; CEA at 2-3; Joint Consumer Comment at 8; CPower at 1-2; DRSG at 2; EEI at 8-11; EEI Reply at 6-7; Elster at 1; EnerNOC at 2; Exelon at 2; FPL at 4; Google at 1; Honeywell at 2; Idaho Power at 4-5; Joint Center at 11-12; NASUCA at 8-9; NRECA at 7; Oncor at 3; Pepco at 1; SCE at 1; SDG&E at 4; Silver Spring at 2; Southern at 3-4; Tendril at 3; US Telecom at 1-3; UTC at 6-7; Verizon at 1-3; Whirlpool at 2; Xcel at 4; Xcel Reply at 4. Some commenters noted that data privacy is particularly important to non-residential or industrial customers because release of the data could result in competitive harm. Avista at 1; EEI at 9; EEI Reply at 6-7; NRECA at 7; SDG&E at 4. Consistent with its comments on data ownership, the Roundtable clarified that at the facility or building level, the consumer who pays the energy bill would be entitled to privacy protections and be able to determine who has access to that data and under what conditions. Particular building tenants are entitled to privacy protections as against the public and third parties, but not the building owner. Building owners need this information to make capital investments and initiate programs to address whole-building energy performance. Roundtable at 3.

To illustrate the importance of privacy protections for consumers, a number of commenters referenced surveys that revealed significant concerns about the privacy of consumer data. A survey commissioned by EEI found that consumers place a very high priority on privacy. Forty-six percent of respondents believe that it is “very important” for their electric usage data to be kept confidential, and 29 percent believe it is “somewhat important”, while 79 percent believed that only utilities and customers should have access to smart meter information. In addition, seventy-two percent of respondents felt the utilities and electric companies do a good or extremely good job with protecting data privacy. NW Energy, PTR at 13-14; EEI at 9. NW Energy also noted that in Montana, a stakeholder group discussion on privacy expectations indicated that this is an important issue to work through. NW Energy, PTR at 13-14. SMUD stated that it had conducted focus groups prior to its Smart Grid roll out that revealed that customers care a great deal about privacy and expect SMUD to maintain data in a very secure manner. SMUD, PTR at 14-15. The CO OCC also noted that energy consumption data raises the potential for Fourth Amendment concerns. CO OCC stated that consumers view Smart Grid efforts as government or industry to control their energy use and know what is going on inside their homes. CO OCC, PTR at 11-13. As a result, privacy protections for consumers’ energy consumption data would be very important to consider.

A number of commenters also stated that utilities should have privacy rights with regard to certain types of data. Cleco at 2 (modified, augmented, or value-added CEUD to the extent not provided in customer billing statements); DTE at 3 (utility proprietary information, including business and marketing plans, sales and marketing data, and financial and operating data); EEI at 9 and EEI Reply at 7 (aggregate data, enhanced or validated individual data, or technical functions of meters and supporting communication infrastructure); UTC at 6-7; Xcel Reply at 9. Xcel noted that releases of aggregate data that could compromise system security should not be made. For example a request for information about loading in a particular neighborhood supplied by limit feeders could result in an indication of the importance of a specific feeder or substation to the distribution of electricity in an urban area. Utilities should also not be forced to disclose data for purposes other than those for which the utility collected the data, creating additional burden on the utilities. NRECA at 7; Southern at 3. DTE believed that only the utility should have privacy expectations in energy consumption data, including individual consumption data. DTE at 2-3. In DTE's view, the owner of the usage data would be entitled to privacy protection. For energy consumption data, DTE stated that the utility that generated the data should own the data and therefore be entitled to privacy protections for that data. The consumer should, however, be entitled to privacy protections for data such as consumers' personal information. The utility could use such data only for business purposes.

Question 3: What, if any, privacy practices should be implemented in protecting energy information?

Comments provided in response to this question are presented below as discussion on three interrelated topics – definitions of energy and other information identified as having privacy implications in the Smart Grid context, potential privacy principles that could be used to develop more specific policies to protect Smart Grid data, and potential state certification and authorization procedures for third party service providers.

Definition of Energy Information.

A number of commenters indicated that a definition of "energy information" was critical to any discussion of Smart Grid issues, including a discussion of what, if any, privacy practices should be implemented to protect that information. In general, three types of data were discussed: personally identifiable information ("PII"), consumer-specific energy usage data ("CEUD"), and aggregate data. All such data can also be enhanced by utilities for business purposes.

One commenter defined PII, as it relates to energy consumption data, to typically consist of an individual's name and address. State privacy laws may include other information as PII, such as Social Security numbers and banking and medical information. The commenter also noted that the definition of PII could vary based on regional understanding. Silver Spring at 1-3. Another commenter added that personal information could also include mailing addresses if different from a service address, personal identifiers such as social security numbers, telephone numbers, and payment history. Avista at 5. NASUCA cited the NIST report on Smart Grid Cyber Security Strategy and Requirements for the proposition that "comprehensive and consistent definitions of [PII] do not typically exist at state utility commissions, at FERC, or within the utility industry," and that the lack of consistent definitions and privacy policies needs to be addressed.[75] NASUCA at 4.

Customer-specific energy use data ("CEUD"), which also pertains to the individual, would according to several commenters include all data specific to an individual customer's energy use, such as total and time differentiated energy and capacity use). EEI at 3; Cleco at 2 (using the

[75] The final draft of this document, NISTIR 7628, is entitled, "Guidelines for Smart Grid Cyber Security", version 1.0, and is available at http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/NISTIR7628v1July2010 (last visited August 10, 2010).

term "customer energy usage data"). Silver Spring used the term "granular consumption data" to mean data that provides detailed information about the energy use of a specific individual or household. Such information could include energy use by time interval, and could also correlate with types of devices in the home such as an electric vehicle. Silver Spring at 1. DTE classified such information under the term "energy consumption data", which it defined as only the amount of consumption of electricity or gas as registered at the meter. DTE at 2-3. Another commenter referenced the efforts of the North American Energy Standards Board ("NAESB") to develop definitions for energy usage data in concert with NIST Smart Grid activities. Elster at 2.

Some commenters appeared to combine the definitions of PII and CEUD. DTE at 2-3; Avista at 5. DTE defined the term "energy information", which could include not only energy consumption data, but also personal information, utility-created information (which could contain proprietary business information), and information that a utility could obtain about a consumer or group of consumers from a third party. Avista referenced the Washington Administrative Code ("WAC"), section 480-100-153(2), which defines "private consumer information" to include the customer's name, address, telephone number, and any other personally identifying information, as well as information related to the quantity, technical configuration, type destination and amount of use of service or products subscribed to by a customer of a regulated utility that is available to the utility solely by virtue of the customer-utility relationship.

Silver Spring commented that aggregate data is assembled by the utility from multiple individuals or households that provide information about energy consumption on a neighborhood or other regional level. Aggregate data does not include PII and cannot be associated with any individual or household. Silver Spring at 2. Another commenter used the term "operational data", which includes data related to the operation of electric utility systems that is not customer-specific but that includes aggregated customer energy usage data. EEI at 6. Aggregate data was defined by other commenters as data recorded by psyncrophaser units ("PSUs"). CPower at 1; DRSG at 1.

Privacy Practices to protect PII, CEUD and aggregate or enhanced data.

A number of commenters noted existing utility policies for the privacy protection of customer information and stated that these policies could expand as Smart Grid technologies develop. These commenters also emphasized that state regulatory commissions have historically had regulatory responsibility in this area. Avista at 3; EEI at 11-12, 19-20, EEI Reply at 7-8; Exelon at 3; FPL at 4-6; NARUC "Resolution on Smart Grid" at 1-2; Oncor at 6; Idaho Power at 5-6; NW Energy, PTR at 13-14; Pepco at 1-2; SCE at 1, 4; SDG&E at 4-5, 10; Southern at 4-5; UTC at 8-9; Xcel at 4; Xcel Reply at 4. NRECA provided further information on state-specific privacy laws, noting that 46 states have laws pertaining to breach notification, and stated that utilities need flexibility to accommodate these state requirements. NRECA at 11.

Many commenters also provided examples of existing and well-established privacy principles that could be adapted for use with Smart Grid. These principles contain consistent and often complementary provisions and include the Federal Trade Commission ("FTC") Fair Information Practice Principles ("FIPPs"), the FIPPs used by the Department of Homeland Security ("DHS"), NIST's Smart Grid Cyber Security Strategy and Requirements, developed by the Smart Grid Interoperability Panel Cyber Security Working Group ("SGIP-CSWG"), the Organization of Economic Co-operation and Development ("OECD") privacy guidelines, guidelines used in other industries, in particular the FCC's regulations on the protection of customer proprietary network information ("CPNI"), and a number of other relevant guidelines.[76]

Several commenters believed that the FTC's FIPPs could be used as a starting point to develop more specific Smart Grid privacy policies. CEA at 3; DRSG at 2, 4; EnerNOC at 4; NASUCA Reply at 7-8; Pepco at 4; TIA at 3; Tendril at 3-4; SCE at 1, 4. Xcel at 6. The FTC's FIPPs consist of five core principles of privacy protection: (1) Notice/awareness. Consumers must be notified of an entity's information practices before any personal information is collected from them. (2) Choice/ consent. Consumers must be given options as to how any personal information collected from them may be used, specifically for secondary uses of information beyond those necessary for utility operations. The choice must also be simple to make. (3) Access/participation. Consumers must be able to timely view the data in an entity's files and contest that data's accuracy and completeness through a simple process. (4) Integrity/security. Entities that collect data must take reasonable steps to assure data integrity, such as using only reputable sources of data and cross-referencing data against multiple sources, providing consumer access to data, and destroying untimely data or converting it to anonymous form. Security involves both managerial and technical measures to protect against loss and the unauthorized access, destruction, use, or disclosure of the data. (5) Enforcement/redress. Means of enforcement and redress are critical to ensure that privacy practices are effective.

A number of commenters also believed that the DHS FIPPs would be appropriate for use in developing privacy standards. CPower at 3; DRSG at 5 (also referencing Department of Health Education and Welfare Fair Information Practices (1973), cited in the DHS FIPPs at 2); FPL at 6; NRECA at 9; Xcel at 6. Though the DHS FIPPs pertain only to PII, they are similar to and build on the FTC FIPPs and consist of several core principles pertaining to the collection and use of the data collected: (1) notifying the individual about PII collection, use, dissemination and maintenance; (2) seeking individual consent to the extent practicable and providing means of access, correction and redress; (3) specifying the authority for and purpose(s) of the collection of PII; (4) collecting and retaining relevant PII only as needed to accomplish identified purposes; (5) using PII only for the purposes specified in the consumer notification; (6) ensuring that PII is reasonably accurate, relevant, timely and complete; (7) protecting PII through appropriate security safeguards; and (8) ensuring collector accountability, including training employees who use PII and auditing the use of PII to determine compliance with the FIPPs and other applicable privacy protection requirements.

---

[76] The FTC FIPPs and additional discussion and reference sources are available at http://www.ftc.gov/reports/privacy3/fairinfo.shtm (last visited August 17, 2010). The DHS FIPPs are available at http://www.dhs.gov/xlibrary/assets/privacy/privacy_policyguide_2008-01.pdf (last visited August 17, 2010). As stated above in fn 9, the final draft of this document, NISTIR 7628, is entitled, "Guidelines for Smart Grid Cyber Security", version 1.0, and is available at http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/NISTIR7628v1July2010 (last visited August 17, 2010). The OECD guidelines are available at http://www.oecd.org/document/18/0,3343,en_2649_34255_1815186_1_1_1_1,00.html (last visited August 17, 2010). The FCC regulations can be found at 49 CFR 64.2009-2111.

Others offered the use of NIST's SGIP-CSWG Smart Grid Cyber Security Strategy and Requirements. APPA at 10; CPower at 3; DRSG at 4-5; EEI at 13, 20; EEI Reply at 8; Elster at 2; EnerNOC at 4; FPL at 6; Google at 2; Idaho Power at 6; NRECA at 10; NASUCA 10-13; Pepco at 6; Verizon at 3 (also referencing efforts of the North American Electric Reliability Corporation ("NERC") Smart Grid task force); Whirlpool at 3; Xcel at 5; Xcel Reply at 5. The NIST report makes a number of recommendations. A privacy impact assessment ("PIA") should be conducted before deploying or participating in the Smart Grid to identify privacy risks, as well as updates to the PIA whenever major changes may affect privacy. Formal privacy policies should be developed and documented that: (1) assign staff to privacy policy implementation; (2) notify customers what data is collected and how it will be used before collecting the data; (3) describe customers' choices in data collection and use; (4) ensure that only data necessary for the specified purposes is collected; (5) ensure that customer information is used and retained only as necessary for those purposes; (6) ensure customers' ability to access, update and correct their own data; (7) ensure that customer-specific information is protected from loss, theft, unauthorized access, inappropriate disclosures and other inappropriate or unauthorized uses. Further, privacy use cases should be employed to address identified exposures or problems, consumers should be educated about privacy exposures and protection options, utilities should share solutions to common privacy problems, and data collections by smart appliances and other devices should be limited to data needed for purposes of operation. See EEI at 20-21; NRECA at 10. DTE noted its involvement in the NIST effort and stated that it is important to ensure Smart Grid decisions do not make obsolete existing equipment deployed in the field by the electric industry to provide reliable service. DTE, PTR at 83-84; see also Southern at 5.

Consideration of the OECD privacy guidelines was also suggested. NRECA at 8-9. The OECD guidelines set forth eight principles of privacy protection: (1) limiting the collection of data and requiring that the data be lawfully obtained, with the consent of the individual where appropriate; (2) ensuring relevancy of data for purposes for which it will be used and ensuring data accuracy, completeness, and currency as necessary for those purposes; (3) notifying consumers of the purposes for which personal data is being collected by the time such data is collected and limiting subsequent use to those or compatible purposes; (4) limiting disclosure of personal data for other than specified purposes without prior consent or under authority of law; (5) protecting personal data from unauthorized access, use, modification, disclosure or destruction through the use of reasonable safeguards; (6) operating with transparency about disclosure practices and policies; (7) allowing individuals to know what data is being collected, to access that data, and to challenge the data as inaccurate, incomplete, or subject to other problems; and (8) providing for accountability to ensure the effectiveness of the other principles.

Some commenters stated that the same privacy guidelines followed by other industries, such as banking, telecommunications, and internet commerce, should be looked to for application to Smart Grid privacy policies. DRSG at 2; Elster at 2; EnerNOC at 3; Honeywell at 2 (while noting that such practices should be used only for data, such as billing data, that needs to be stored on a centralized server; energy use data should be transmitted directly from the meter to the customer premises, without transfer to vulnerable exterior networks); Whirlpool at 2. In particular, EEI discussed the potential for use of the FCC regulations for the protection of CPNI in the telecommunications industry as a possible guide for Smart Grid privacy practices. EEI at 14-15. The FCC regulations set forth requirements for telecommunications carriers to establish a clear system for determining whether a customer has given approval for the use or release of CPNI, including records retention policies and a disciplinary process for employee misuse of CPNI. The regulations also set forth requirements for protecting against unauthorized access to CPNI, which include procedures to authenticate customers who call or go online in order to access CPNI. Notification procedures in the event of a security breach are also set forth in the FCC regulations, which include requirements pertaining to the notification of law enforcement prior to customer notification.[77]

Other commenters referenced various other potential privacy practices for use in protecting energy consumption data generated through use of Smart Grid technologies. A few commenters suggested use of the Privacy by Design concept developed by the Information and Privacy Commissioner of Ontario, Canada, which envisions building fair information practice principles into the design, operation and management of information processing technologies and systems. NASUCA at 13-15; Pepco at 4-5. Privacy Impact Assessments ("PIAs"), privacy evaluations used in developing new systems, can be used by utilities and state regulatory bodies to guide their planning for the protection of Smart Grid data. PIAs set forth questions for applicants to answer related to the collection and storage and encryption of data, as well as consumer consent and notice in the event of a breach. PIAs could also be used in connection with Federal funding for Smart Grid, particularly given that some form of PIA is already used by a number of Federal agencies. NASUCA at 13-15. See also EEI at 20 (referencing PIAs in the context of NISTIR 7628). A few commenters also referenced the Fair Credit Reporting Act, as amended, and the associated Red Flags Rule for preventing identity theft. APPA at 10; DTE at 4; NRECA at 11. Other commenters mentioned the American Institute of CPA's (AICPA) Generally Accepted Privacy Principles (GAPP)[78], draft customer access guidelines developed by EEI, and Gramm-Leach-Bliley Act requirements. NRECA at 9, Cleco at 2-3, Pepco at 4-6.

Other commenters, while not advocating for the consideration of any particular guidelines, set forth principles they believed were appropriate. APPA believed that such policies should include the limitation of data collection, clear disclosure to customers, visible and transparent privacy rules, customer consent for the release of information to third parties, technology and practices that ensure data integrity, customer access to data, notification in the event of security breach or inadvertent disclosure, and security safeguards to protect against unauthorized access. Secure communication technologies should also be used to transfer smart meter data, or the data should be encrypted where secure transfer is not possible. APPA at 6. These policies are consistent with those in the FIPPs and other data privacy principles discussed above. See also Avista at 1-2; DTE at 3; Elster at 1; FPL at 4; Idaho Power at 5; Silver Spring at 3 (all setting forth policies that they believed should be used to safeguard energy information); Xcel Reply at 7 (setting forth the elements of consumer consent: allowable uses of data; duration of time for which consent is valid; and (3) process by which consumer may revoke consent). NW Energy also commented that utilities now shoulder many responsibilities, such as reliability, network

[77] Relatedly, 49 CFR 64.11120(c)(3) sets forth requirements for the verification of orders for telecommunications services governing the method in which carrier change orders can be submitted, conducted, and verified.
[78] The AICPA's GAPP can be found at http://www.aicpa.org/InterestAreas/InformationTechnology/Resources/Privacy/GenerallyAcceptedPrivacyPrinciples/Pages/default.aspx (last visited August 18, 2010).

operation, and renewable energy, but that utilities are uncomfortable with importing parts of the Federal criminal code into reliability for utilities. NW Energy, PTR at 81-82.

Related to the principles discussed above, a number of commenters stated any data privacy practice should hold third parties to the same security standards as the utilities. EEI at 14, 30; Elster at 4; Exelon at 3-4; Oncor at 8; SMUD, PTR at 64-65; Tendril, PTR at 42; US Telecom at 2. Tendril, a third party vendor, also stated that utilities must audit heavily the vendors they use to generate or manipulate data. For its part, Tendril goes through three-week, 20-person security audits with utilities, to make sure that the bits of data Tendril uses are stored correctly and meet the same set of requirements that the utility has to meet for customer data. Tendril, PTR at 42-43. In addition, only authorized third parties should have access to data enhanced by utilities for business purposes. EEI at 33-34; FPL at 10; SDG&E at 3, fn 3.

State Certification of third party service providers and Authorization Procedures.

EEI discussed in detail the importance of state certification of third party service providers[79] to ensure that such providers met certain basic requirements to safeguard the privacies and energy usage information of utility customers. EEI urged the states to consider adoption of such procedures and indicated that DOE could develop guidance to assist the states in issuing their own procedures. Federal agencies could also offer guidance for validating third parties who have received state certifications. EEI at 10-11, 14, 29-32. See also Pepco at 1 and 6; NASUCA Reply at 7. As a related issue, EEI also discussed authorization procedures that could be used to ensure that third party service providers have received appropriate authorization from consumers to access, use or disclose consumer data. To ensure that such authorization is informed, consumers should be provided with clear information on the nature and use of the data to be disclosed. In many instances, electronic consumer consent should be sufficient, and while a "wet" signature would not be required, consumers should be provided the option to authorize data disclosure in this manner. EEI at 10-11, 14, 29-32. In developing any guidance documents on state verification and authorization procedures, DOE should consider the FCC regulations discussed above, as well as NIST's recommendations on third party authentication and authorization. EEI at 10-11, 14, 29-32; EEI Reply at 9.

Question 4: Should consumers be able to opt in/opt out of smart meter deployment or have control over what information is shared with utilities or third parties?

While a few commenters stated that consumers should be able to opt out of Smart Grid deployment, most agreed that consumers should be required to take part in smart meter deployment and allow utilities access to energy consumption data to achieve reliability, environmental, and other benefits. The pace of deployment, however, could depend on a number of of factors. Commenters were universal in agreeing that consumers should have control over whether their individual energy consumption data is shared with third parties. Commenters also

[79] EEI defines third party service providers as parties not under contractual obligations with an electric utility to keep customer information confidential and who, therefore, require customer consent to receive such information. EEI at 3, fn. 2; EEI Reply at 3, fn 5. See also DTE at 5.

discussed means to encourage consumer acceptance and use of Smart Grid, noting that education and the provision of tangible, immediate benefits would be important factors.

Consumer Participation in Smart Grid Deployment.

In responding to the issue of whether all consumers will need to use advanced Smart Grid infrastructure if utilities are going to invest in smart meters, or if the nation is going to achieve goals related to renewable energy, or take advantage of things like electric vehicles, most commenters agreed that it does not make sense for only some consumers to use Smart Grid, because the resulting data would be potentially harmfully incomplete data. Utilities need the data for all consumers to understand the load on a transformer, so they can do preventative maintenance, and to know whether the transformer can handle electric vehicle infrastructure. Because electric vehicles, when charging, can consume an amount of energy similar to that consumed by an entire household, it is critical that utilities have access to information regarding electric use of these vehicles. APPA at 7; Avista at 2-3; BG&E at 2; Cleco at 3; DRSG at 3; DTE at 3; EEI at 15-17; EEI Reply at 6, 9-11; Elster at 1; EnerNOC at 3; Exelon at 4; FPL at 4-5; Honeywell at 2-3 (also noting that the consumer should be able to opt out of the collection of detailed consumption data, as opposed to billing data); Idaho Power at 5-6; NASUCA at 15; NRECA at 12-13; Oncor at 3-4; Pepco at 2; Sawnee, PTR at 56; SCE at 2; SDG&E at 5-6; Silver Spring at 3-4; SMUD, PTR at 55-56; Southern at 4; TIA at 3; TechNet, PTR at 57; Tendril, PTR at 21-22; Tendril at 4[80]; TIA at 3; UTC at 9-10; Whirlpool, PTR at 46-47; Whirlpool at 2-3.[81] NW Energy also stated that the utilities need the data to provide safe and reliable service and to meet various accountabilities. For example, the data would be used for critical infrastructure audits, and there would be more risk with more porous data. Data is also needed to comply with state law requirements. NW Energy, PTR at 40-41.

A few commenters argued that consumers should be able to opt-out of the deployment of Smart Grid technologies that are used by consumers—as opposed to those on the utility-side of the meter. CPower at 2 (noting that the ability to opt out of individual metering deployment was the consumer's right); Xcel at 4-5 (noting that because of the benefits of broad deployment, opt-in deployment should be considered as one way to promote smart-meter usage). The Joint Consumer Comment, for example, stated that use of smart meters and time of use pricing should be optional wherever possible. It suggested that an opt-out regime makes smart meters a more appealing option and protects those for whom it is not cost-effective, such as low volume users. Joint Consumer Comment at 5. Sawnee also cautioned that we need to tread carefully with the

[80] Tendril also stated that utilities need whole house, aggregated data to make quick decisions about how much power to generate, or whether to turn on a new power plant or turn down customers' air conditioners (for those customers who have opted in). For the utilities to meet their goals of introducing renewable energy sources, gaining more efficiencies, and managing load demand more efficiently, a system that can measure whole house consumption at approximately 15 minute intervals is needed. Such a system can be created either by putting in new smart meters or using existing automated meter reading (AMR) meters linked to the customer's broadband. As discussed above, however, there is one exception to the utilities' need for aggregated whole house data only – energy data on usage of electric vehicles. Because an electric vehicle, when plugged in, will use more energy than the entire house, knowing how much energy the vehicle needs and when the battery needs to be fully charged allows a utility to optimize how much power is sent to a particular neighborhood to meet those requirements. Tendril, PTR at 20-22, 26.

[81] While not giving an opinion on whether consumers should be able to opt out of Smart Grid deployment, CEA stated that providing such an option would hinder development and deployment of Smart Grid. CEA at 3-4.

idea of not allowing consumers the choice to opt out, because imposing the system on people would result in a challenge. Sawnee, PTR at 28-29. The Roundtable, while stating that individual tenants should not have the ability to opt-out of smart meter deployment, left open the possibility that, if the utility did not install the smart meters, private companies for whom the investment was not cost-effective could opt out of deployment within particular buildings owned by that company. Roundtable at 4-5.

While stating, for the most part, that consumers should not be able to opt out of Smart Grid deployment, commenters acknowledged that varying paces of investment in or adoption of Smart Grid were possible. Some stated that utilities should determine whether and when to deploy smart meters, or that these decisions should be made at the state level by state regulatory commissions. APPA at 7; Avista at 2-3; Cleco at 3 (noting that utilities should be able to recover the costs of deployment); EEI Reply at 11; NASUCA at 15-16; NW Energy, PTR at 48. Sawnee noted that consumer acceptance could also drive the pace of Smart Grid adoption. Individuals need to see that use of Smart Grid is to their own benefit, and it is important to have a culture and environment that supports energy efficiency measures but allows people to move along the continuum at their own pace. Sawnee, PTR at 47. NW Energy acknowledged the continuum, but noted the issue of demands for a particular utility, the vintage of its existing equipment, and other issues that would presumably result in the need for faster movement along that continuum. NW Energy, PTR at 48. TechNet discussed an adoption curve for Smart Grid, where utilities and others make investments in the meters and other equipment, and then consumer adoption catches up over time. PTR, p. 57. Whirlpool also acknowledged that manufacturers need to start making appliances that are Smart Grid compatible because if they do not, critical mass will never be achieved. PTR, p. 58. CO OCC noted, however, that while smart meters cost $5 – $95, the Smart Grid is costing $2200 per household for a trial while there was an alternative display device for use with the smart meter that costs only $250, so a real issue exists over how much utility customers should be required to pay. PTR, p. 58. NW Energy queried when it might sensible to change out a generation of technology, such as AMR to advanced metering infrastructure ("AMI"). It can be difficult to justify a new generation of meters, but NW Energy noted that there is now technology that lets utilities bridge from AMR to something that "looks like" Smart Grid. NW Energy, PTR at 62.

Consumer Ability to Opt-Out of Energy Information Sharing.

On the issue of sharing with third parties energy usage data collected through consumer use of Smart Grid technologies, commenters were universal in the view that consumers should be able to opt-in or opt-out of sharing their individual energy usage information with third parties. APPA at 7; Avista at 2-3; BG&E at 2-3; CEA at 4; Cleco at 2; CPower at 1-2; DRSG at 3; DTE, PTR at 86; EEI at 17; EnerNOC at 2-3; FPL at 5; Google, OSTP Comments at 2; Honeywell at 3; Idaho Power at 6; NASUCA at 16; NW Energy, PTR at 41, 45; Oncor at 4-5; Pepco at 2; SCE at 2; SDG&E at 5-6; Silver Spring at 4; SMUD, PTR at 28, 55-56; Southern at 4; Tendril, PTR at 21-22, 36, 43-44; Tendril at 4; TIA at 3; US Telecom at 1-2; UTC at 10 (noting that policies adopted in the 1990s on the utilities sharing customer data in the context of retail competition could be used in the Smart Grid context as well); Verizon at 2-3; Whirlpool at 2-3; Xcel at 4-5. SMUD elaborated that, in the focus groups they conducted prior to their Smart Grid roll out, a great deal of concern was voiced about who will control the data and what kind of decisions

SMUD would make regarding sharing of the data. Customers indicated that they want to be able to say how their information is used, and they want to be able to tell SMUD how their information can be used. SMUD, PTR at 14-15. Cisco Systems ("Cisco") similarly noted that consumer views on privacy vary widely and the varying views are all valid, so the privacy issue must be viewed from a consumer control point of view. Cisco, PTR at 15-16. Avista further clarified that the consumer should be able to opt out of the collection of information on the energy consumption, or the control of, appliances on the customer side of the meter. Avista at 2-3.

Some commenters offered views on whether consumer control of data sharing should use an opt-out versus an opt-in mechanism. A number of commenters preferred the opt-in mechanism because it would not require affirmative action by the consumer to prevent the sharing of his or her energy consumption data. DTE, PTR at 86; EEI at 17, 24; Honeywell at 3; NASUCA at 16; Oncor at 4; Pepco at 6; Southern at 4; TIA at 3. Two commenters seemed to prefer the opt-out approach, but did not provide specific reasons as to why such an approach should be preferred. Exelon at 2; Xcel at 5. CEA stated that no particular mechanism should be selected at this time to avoid hindering innovation in the development of consumer consent mechanisms and the widespread deployment of Smart Grid. CEA at 4; see also Silver Spring at 4. Tendril, a third party vendor currently collecting energy use data, noted that while its programs dealing with the whole home consumption data shared with utilities may not be opt in, all of its programs that use disaggregated data about what's going on inside the home are opt in. Tendril, PTR at 36, 42-43. Tendril further noted that their next software release will allow consumers to go to the utility website and see what data is being captured and who has access to it. Consumers can then determine what they want to have happen to that data. Because different people have different thresholds or trade-offs for use of their data, Tendril believes that it is important to offer people choices. For example, to save money, Tendril explains that the consumer must allow the vendor to use a reasonable amount of behavioral information, such as when a person is at home and to what temperature the person's thermostat is set, and makes that clear to the customer. Tendril, PTR at 44-45.

A number of commenters also clarified that consumers would not need to authorize utilities to access data or share that data with a third party the utility uses for operational purposes. APPA at 13-14; CPower at 4; DRSG at 8; EEI Reply at 6; EEI at 3, fn 2; Exelon at 2; NASUCA at 25; NW Energy, PTR at 42; Oncor at 4, 8; SCE at 6; SMUD, PTR at 39, 42, and 54; Southern at 4; UTC at 15; Whirlpool, PTR at 46-47; Xcel at 7-8; Xcel Reply at 5. Some also commented specifically that consumers should not need to authorize the sharing of aggregated data, as long as consumers are informed of the practice and appropriate safeguards are in place to prevent the ability to infer PII or individual usage data from the aggregated information. CEA at 2; CPower at 1-2.

Means to Encourage Consumer Acceptance and Use of Smart Grid.

Commenters offered a number of ways to increase consumer acceptance and use of Smart Grid technologies. Education about the benefits of Smart Grid was discussed as a primary means of achieving this goal. Commenters also discussed how to provide consumers with at least some immediate benefits from use of smart meter technologies to further encourage consumers to accept Smart Grid. Some commenters also believed that allowing consumers to use variable pricing would be a valuable tool.

A number of commenters noted that educating consumers about the benefits of Smart Grid would help increase consumer acceptance and use of Smart Grid. CEA at 4; CO OCC, PTR at 12-13, 32, 53, 102 (also noting that use of inverted block rates would not be very successful because consumers did not understand the concept); NW Energy, PTR at 13-14, 62; TechNet, PTR at 16-17, 31, 99; SMUD, PTR at 29, 48, 97; TIA at 3-4; Tendril, PTR at 58-59; DTE, PTR at 83-84. These commenters also discussed how different technologies could allow consumers to see some energy use data or other information right away, an immediate benefit that would further encourage consumers to use Smart Grid technologies. As examples of such information, Landis and Gyr (“Landis”) commented consumers could be provided with an in-home display, such as the displays they are considering offering in Texas to low and fixed-income consumers. How to get the displays into consumers’ hands and who pays for them, however, are open questions. Landis, PTR at 89. Tendril noted that being able to look at your bill on your iPad was another example of an immediate consumer benefit. Tendril, PTR at 90. SMUD stated that immediate benefits could also include information on a bill or providing access to the utility’s web portal on their utility usage, as well as tips on how to cut energy usage. SMUD, PTR at 97. Consumer education about less tangible or personal benefits could also help to encourage Smart Grid use for some consumers, through the desire to be energy efficient for environmental reasons For example, SMUD referenced its program that allows people to pay more for 100-percent renewable energy and noted that many people use solar even though it is not cost-effective. SMUD, PTR at 52.

Commenters also discussed more detailed programs that could help consumers save money and increase acceptance of Smart Grid. Tendril noted its creation of a point system similar to that used in some recycling programs to give people points for doing things that are energy efficient, and those points are redeemable at Target, Starbucks, and other locations, or can be used to help local schools. PTR, p. 48-50. Cisco provided as another example the GooglePlex, a multi-protocol router that interfaces with all the different energy control systems to identify whether appliances are running efficiently and to turn energy-using devices on and off. Cisco stated that the GooglePlex saved Google up to 40 percent on their energy costs. Cisco noted that these control access systems could be installed in consumers’ homes going forward. PTR, p. 50-51.

Commenters also discussed price signals as a way to encourage adoption of Smart Grid. SMUD stated that we need to build pricing so that utilities recover costs, and at some point there could be an environmental adder associated with greenhouse gases. SMUD, PTR at 29. Cisco agreed that it makes sense to do time of day pricing to discourage high cost production, because the marginal cost of additional production at peak time is extremely high, and the cost averaging that is currently used removes the incentive to do anything about this issue. Cisco, PTR at 30. Tendril also noted that we need to use price as a driver. In addition, to make variable price work in a consumer sense, Tendril stated we need devices that can autonomously react – consumers can set up a rule that says if the price goes above X, change my thermostat to Y. If consumers have to do this manually every time, they won’t interact with the system. Tendril would push utilities to give people a variable rate along with the flat rate, and they pay the lesser of the two, to educate people in the short term, because everyone can benefit from variable prices. This would be a good start, to give consumers the choice whether to use the variable pricing. Tendril, PTR at 27-28.

Question 5: What mechanisms should be made available to consumers to report concerns or problems with the smart meters?

Most commenters who addressed this issue indicated that current mechanisms used by utilities to address customer complaints should be used to address concerns with smart meters. APPA at 8; BG&E at 3 (also noting that use of networked devices on the customer side of the network may introduce additional complexities); DTE at 3; EEI at 17-18 (also noting that customers could also use any new, emerging technologies to communicate concerns); FPL at 5; Idaho Power at 6; Pepco at 3; Southern at 4-5; SCE at 2 (also noting that customers should be able to use any new, emerging channels to communicate concerns); UTC at 11. NASUCA stated that utilities should communicate the mechanisms available to address Smart Grid issues to consumers on an annual basis, and that these methods should include a phone and internet service hotline. NASUCA at 17. SDG&E also indicated that customer service representatives specially trained to address matters related to smart meter deployment are available to assist consumers in the event that initial contacts with customer service do not resolve a particular issue. SDG&E customers can also voice concerns in various forums such as public meetings. SDG&E at 7. Many commenters also stated that if a customer's attempt to resolve a concern with the utility is not successful, a state regulatory commission should provide assistance. DRSG at 3; Elster at 5; EnerNOC at 3; Exelon at 2; Honeywell at 3; Oncor at 5; SDG&E at 7-8; Southern at 5; UTC at 11. In addition, Tendril noted that customer concerns with smart meters may be redressed differently than concerns with use of customer data by third parties. Customer concerns with utility practices could be directed to state regulatory commissions, while concerns with third party practices could be directed to state Attorneys General, the FTC, or the FCC, similar to practices in place for other industries. Tendril at 5. Two commenters also believed that an independent ombudsman services could be made available to address consumer concerns with smart meters. CPower at 2; Tendril at 4.

Question 6: How do policies and practices address the needs of different communities, especially low-income rate payers or consumers with low literacy or limited access to broadband technologies?

A number of commenters indicated that Smart Grid data privacy policies should apply equally to all consumers. APPA at 9; DTE at 4; EnerNOC at 4; Tendril at 5. Reponses to this question, however, generally focused on the extent to which the benefits of Smart Grid accrue to low income consumers, as well as on how government entities, utilities, and others could help low income consumers engage in and benefit from the use of Smart Grid technologies through the use of education and financial assistance programs. Many commenters stated that decisions concerning such assistance would be addressed before state utility commissions.

Commenters differed on the extent to which Smart Grid technologies would benefit low income consumers. One commenter specifically argued that low-income residential consumers would not benefit from Smart Grid because they often have lower energy consumption and therefore fewer opportunities to conserve energy. APPA at 8-9. As a result, APPA argued that time of use rates should be introduced carefully to this customer class, and the use of block tariff rates may be an appropriate way to proceed. The Joint Center for Political and Economic Studies ("Joint Center") argued that insufficient information exists to determine whether AMI benefits or harms low-income consumers. The Joint Center referenced a pilot program conducted by the National Regulatory Research Institute, which showed that lower income consumers reduced electricity demand by lower percentages than higher income consumers, and that there was no universal demand reduction (in some cases, demand increased) during peak periods.[82] Based on this pilot, the Joint Center echoed the APPA's concern that many low-income consumers do not stand to realize Smart Grid benefits because they are already subsisting on bare energy expenditures due to limited incomes, and they are unable to shift such use to take advantage of off-peak rates. In addition, they may live in homes that are less well-insulated or have less-efficient appliances. The Joint Center stated that further studies on AMI use by the low income need to be conducted. Joint Center at 9-10.

Other commenters emphasized that use of smart meters and Smart Grid technologies like direct feedback on energy use would benefit all consumers, particularly those with low incomes, by helping them reduce their energy usage. CEA at 4 (noting that the PowerCents DC pilot program indicated that consumers reduced their demand by up to 50 percent, and low income consumers enrolled at higher rates than other consumers); EEI at 18; EEI Reply at 11; FPL at 5; Google, OSTP Comments at 2; NASUCA at 18; Pepco at 3-4 (discussing the Smart Meter Pilot Program, Inc. which indicated that low-income consumers respond to dynamic pricing signals, thus reducing their electricity costs); Silver Spring at 4; UTC at 12 (referencing a study that revealed that low income customers are responsive to dynamic rates and can benefit even without shifting load, and that they do shift load in response to price signals).[83] The Joint Center also agreed with this general principle. Joint Center at 1. Silver Spring further stated that low income customers typically have flatter load curves than average, meaning that they subsidize consumers with "peakier" consumption patterns and would thus benefit from more efficient cost allocation through dynamic pricing. EEI and a number of other commenters elaborated that benefits such as improved power quality, increased reliability, increased safety, faster service restoration, and increased utility productivity. See also CEA at 4; FPL at 5; Oncor at 5-6; Pepco at 4; Southern at 5.

Commenters acknowledged that low-income communities should be included in any public debates and discussions that occur as Smart Grid strategy is developed, and that any studies or pilot programs relating to smart meter technologies should also include such customers. Joint Center at iii; Exelon at 3; NASUCA at 18; Pepco at 3; UTC at 11-12. In addition, commenters stated that there was a need for flexible assistance programs for low-income persons and other groups. Joint Consumer Comment at 5-6; DTE at 4; Southern at 5. Some commenters indicated

[82] N. Brockway, "Advanced Metering Infrastructure: What Regulators Need to Know About its Value to Residential Consumers", National Regulatory Research Institute (February 13, 2008). http://nrri.org/pubs/multiutility/advanced_metering_08-03.pdf (last visited, August 23, 2008).

[83] "The Impact of Dynamic Pricing on Low Income Customers", IEE Whitepaper, June 2010, prepared by Ahmad Faruqui, Ph.D., Sanem Sergici, Ph.D., and Jennifer Palmer, A.B.

that state utility commissions were in the best position to evaluate and make decisions regarding such programs. DRSG at 4; EEI Reply at 12-13; Southern at 5; Tendril at 5.

Commenters believed that such assistance programs should include education programs for low-income rate payers or consumers with low literacy or limited access to broadband technologies. APPA at 9; DRSG at 4; EEI Reply at 14; EnerNOC at 4; Joint Center at 2, 5-6; NASUCA at 19; CO OCC, PTR at 32; Oncor at 6; SCE at 4; Silver Spring at 4; SMUD, PTR at 29; TechNet, PTR at 16-17; Tendril at 5; Whirlpool at 3. TechNet added that education efforts need to include the HUD housing sectors so that large portions of the population are not left behind in the implementation and use of Smart Grid. Because the knowledge level of these individuals is currently very low, education programs or informational materials would be helpful. TechNet, PTR, p. 31. Education programs should also include persons who do not speak English. DRSG at 4; EEI Reply at 14; EnerNOC at 4; Joint Center at 4; Silver Spring at 4; SCE at 4. SDG&E also discussed its program to train community librarians to assist customers without home internet access in creating accounts to view their energy usage online. See also EEI at 19 and EEI Reply at 14 (noting that education efforts must be made to reach those without access to computers or the internet).

In addition, commenters believed that monetary assistance programs would benefit these consumers. Such programs could include government subsidies, incentives, or other means of assistance. BG&E at 4; TechNet, PTR, p. 31-32; SDG&E at 9-10; SCE at 3. State-mandated assistance programs should also be reviewed and modified to operate effectively alongside use of Smart Grid technologies. NASUCA at 19. Programs underwritten by utilities that provide financial assistance or early access to Smart Grid technology would help low-income customers who pay their own electricity bills recover the cost of increased tariffs associated with Smart Grid. Tendril, PTR, p. 58-61. See also Oncor at 6; Pepco at 3; SCE at 3; Tendril at 5 (discussing programs under consideration by utilities to provide free or low cost in-home energy use monitors). Commenters also stated that reducing operating costs for the roughly 2 million housing units controlled by HUD or a non-profit would also reduce the rent of the individuals impacted by the operating costs for those units (even if these individuals did not directly pay the utility bill), as well as improve the fiscal health of the entity supplying the housing. TechNet, PTR, p. 61; Joint Center at 5-6. One commenter noted that it partners with community action organizations to assist low income consumers with payment of their utility bills, as well as to assist customers with special needs, such as the elderly and the handicapped. Avista at 3. Some commenters cautioned, however, that any financial incentives to low-income consumers should not stifle innovation by picking technological winners and losers. CEA at 5; Honeywell at 4.

In addressing the issue of broadband access by low-income consumers, commenters differed on whether use of broadband would be necessary for consumers to reap the benefits of Smart Grid. Some commenters stated that broadband should not necessarily be required, as other technologies are available that could help such customers lower their energy usage, and thus save money on their energy bills. BG&E at 4; DRSG at 4; Elster at 2; EnerNOC at 4; Exelon at 3; FPL at 5; Oncor at 5-6, 10. Multiple competing ways to receive energy data will help ensure the broadest and lowest cost access to data. Google at 2. Another commenter, however, believed that reliance on broadband technologies to transmit data was inherent in Smart Grid design, and that increased efforts to improve digital literacy and access to public computing centers would be needed to help low-income consumers learn how to use and manage Smart Grid technology. Joint Center at 2-4.

A number of other views on financial assistance and related issues were also expressed. Other commenters argued that innovation in the free market will provide low-income consumers with cheaper products, financing opportunities and other services. CPower at 2-3; Honeywell at 4. In another commenter's view, low-income persons who install smart meters should not be required to participate in any new program or be subject to any different type of pricing or rate. The relationship of such customers with their utility should continue as before unless consumers choose to participate in any programs to manage their electric bills to lower costs. DRSG at 4. One commenter also voiced concern about the effect of remote disconnection on low-income or elderly consumers, stating that consumer protections from remote disconnections should not erode with the roll out of smart meters, and that health and safety reviews should be required even if technology enables remote disconnection. Joint Consumer Comment at 5-6.

Question 7: Which, if any, international, federal, or state data-privacy standards are most relevant to Smart-Grid development, deployment, and implementation?

Many commenters discussed international, federal, and state data-privacy standards that could be relevant to Smart Grid development, deployment, and implementation in response to Questions 3 and 16. Please see those Questions for discussion on these topics.

Question 8: Which of the potentially relevant data privacy standards are best suited to provide a framework that will provide opportunities to experiment, rewards for successful innovators, and flexible protections that can accommodate widely varying reasonable consumer expectations?

Commenters on this topic emphasized the need for an overarching framework of privacy guidelines rather than detailed standards for the protection of consumer privacy. They also offered views on whether a state or federal standard would be more appropriate, as well as on the use of international standards. Commenters also discussed the level of privacy assurance that standards should provide and highlighted the importance of investing in innovative technologies.

Many commenters stated that a framework setting forth the important elements of privacy protection would foster innovation more readily than prescriptive data privacy requirements dictating specifically how utilities and others would need to protect consumer privacy. [84] This is particularly important because the kinds of applications and software that may be developed are as of yet unknown. Cisco, PTR at 68-69; CPower at 3 and DRSG at 6 (stating that a threshold

[84] We note that the Department of Commerce (DOC) is conducting an inquiry exploring precisely this issue of the relationship between innovation and consumer data privacy. *See* U.S. Dep't of Commerce, Notice of Inquiry on Information Privacy and Innovation the Internet Economy, 75 Fed. Reg. 21226, Apr. 23, 2010. The inquiry covers many of the issues discussed in this section, including the effects of state-level privacy laws and federal sector-specific privacy laws. DOC will issue a report setting forth the findings of this inquiry. The FTC is conducting a similar inquiry and will issue a report discussing the U.S. consumer privacy framework, *See* FTC, Exploring Privacy: A Roundtable Series, http://www.ftc.gov/bcp/workshops/privacyroundtables/.

should be set, like the principles in the FTC FIPPs, with flexibility and innovation encouraged beyond that threshold); DTE at 4 (recognizing the AICPA GAPP and OECD guidelines); EEI at 21-22 (recognizing NISTIR 7628); EnerNOC at 4 (referencing the FTC FIPPs and the NIST Cyber Security Coordination Task Force effort); FPL at 7 (referencing the NIST CSWG forum); Google DOC Comments at 2-3 (referencing the Gramm-Leach-Bliley Act and FTC privacy rules); Idaho Power at 6-7 (recognizing the NIST effort to develop privacy standards); NASUCA (referencing the NIST report and Privacy by Design efforts it discussed in response to Question 3); Pepco at 6; Sawnee, PTR at 95; SCE at 4 (referencing the FTC FIPPs); SDG&E at 10-11 (referencing the NIST CSWG report); Silver Spring at 6 (discussing the need for a threshold beyond which innovation can flourish); Tendril at 5 (referencing the FTC FIPPs). Tendril further noted that within that framework, the market should be allowed to operate. Tendril, PTR at 75-76. Regional diversity could also be supported and flourish within that framework. Sawnee, PTR at 105.

Those in support of state responsibility in this area emphasized that states have traditionally taken the primary role in regulation for the protection of consumer privacy. APPA at 11 (also noting that there may not be much room to experiment with data privacy guidelines given existing state laws); Elster at 3 (noting that political jurisdictions can choose to be more restrictive); Oncor at 6; Southern at 5. Southern noted that allowing states to take the lead in this issue will allow them to act as laboratories of experimentation (citing New State Ice Co. v. Liebmann, 285 US 262, 311 (1932)).

Other commenters, while acknowledging that privacy concerns have typically been dealt with on a state-by-state basis, believed that standardized data privacy standards are important as we move forward with Smart Grid development. NW Energy, PTR at 94; SMUD, PTR at 64-65; Whirlpool, PTR at 94, 105 (acknowledging that diverse needs exist, but noting that a national standard framework would allow appliance manufacturers to help with demand responsive load leveling); Whirlpool at 4. Tendril stated that the issue is about efficiency, particularly for companies selling products across multiple state boundaries. Because it is difficult to deal with 50 sets of requirements, least best practices should be defined, and then states could deviate if needed. Tendril, PTR, at 72, 93. NW Energy clarified that given that Smart Grid technology is still relatively new, there has been insufficient time for experimentation, and that freezing this experimentation in a single federal standard would at this point be premature. The Federal government could, however, facilitate the development standards. NW Energy, PTR at 74.

A number of commenters explored the idea of a federal minimum standard with states determining whether more stringent standards should be implemented. NASUCA argued that states should be able to be able to implement more stringent than any federal guidelines, but acknowledged that federal privacy regulation may be needed given interconnected nature of Smart Grid. NASUCA at 19-20; NASUCA Reply at 6 (stating that there is a need for a national privacy policy to establish a minimum level of protection, while enhancing the state role in promulgating privacy protection rules). The CO OCC referenced the existing model in use for Consumer Proprietary Network Information when querying whether it would be appropriate to have minimal federal standards and allow states to have more stringent privacy standards. CO OCC, PTR at 94. See also AARP Reply at 5 (agreeing that there should be a Federal floor while states could establish more stringent requirements; Federal action should not stifle State efforts and discourage policy innovation). See also AARP Reply at 4 (noting that both the federal and state governments must implement policies to ensure that customers' personal and energy consumption data is protected). NW Energy also stated that there is a role for both the states and for the federal government in developing such a standard – perhaps the federal floor and state ceilings would be an appropriate model. NW Energy elaborated that any standards should not be developed by a federal agency through a rulemaking process. Instead, the standard should be industry-driven and respond to customer experience, and utilities should communicate with state agencies. NW energy indicated that standards should be harmonized and technology and commercially driven, noting that companies have internal practices for protecting consumer data that are continually reviewed. NW Energy also believes that it would be a huge mistake for states and federal agencies to get into a jurisdictional fight, particularly because it is likely that the process would not end with the right result. NW Energy, PTR at 94-95.

One commenter indicated that international standards might best foster innovation and flexibility because they must recognize privacy expectations worldwide. Elster at 3. On the other hand, one commenter noted that the inconsistencies between existing international standards may make it difficult to use these standards to develop appropriate privacy policies. Google, DOC Comments at 6-7 (though noting that Asia-Pacific Economic Cooperation ("APEC") Privacy Framework[85] and OCED guidelines could help in the development of effective privacy principles).

In determining the level of privacy assurance that any standard or framework should offer, commenters agreed that while we rightly expect from our utilities a high level of service, in terms of reliability and other factors, the high bar cannot become an inhibitor to progress, or the many benefits from Smart Grid may not accrue. Tendril, PTR at 103. While it is important to deliver cost-competitive energy to customers, we cannot inhibit creativity and innovation to prevent customers from seeing a value proposition in use of the Smart Grid. Sawnee, PTR at 104. One commenter further highlighted the need to provide oxygen to innovation and to continue to drive investment, which would produce jobs. The commenter noted that the federal government can seed investment through stimulus. The commenter also noted the importance of the federal role, to put up a firewall for consumer protection and the safe use of information. TechNet, PTR at 98-99.

Question 9: Because access and privacy are complementary goods, consumers are likely to have widely varying preferences about how closely they want to control and monitor third-party access to their energy information: what mechanisms exist that would empower consumers to make a range of reasonable choices when balancing the potential benefits and detriments of both privacy and access?

Commenters acknowledged that consumer views on privacy vary widely. See, e.g., Cisco, PTR at 15-16; SDG&E at 11. Cisco stated that because the various consumer views are all valid, we need to look at the issue from a consumer control point of view. Because Smart Grid technology

[85] The APEC Privacy Framework is available at http://www.ag.gov.au/www/agd/rwpattach.nsf/VAP/(03995EABC73F94816C2AF4AA2645824B)~APEC+Privacy+Framework.pdf/$file/APEC+Privacy+Framework.pdf (last visited August 18, 2010).

is still new, we have the opportunity to deploy it in a way in which security and the protection of consumer privacy is incorporated in a significant and meaningful way. We can deal with issues of consumer privacy appropriately if we deploy systems intelligently. Cisco, PTR at 15-16.

Some commenters stated that existing utility practices could be used and adapted to allow consumers to control access to their data. APPA at 11; Avista at 4-5; DRSG at 6; Elster at 3; Oncor at 7; SDG&E at 12.[86] APPA stated that existing utility customer internet portals could be used to provide consumers with access to Smart Grid information and choice in determining whether to release their data to third parties. Avista referenced existing Washington state law governing disclosure and notice to customers of its disclosure policy. DRSG also noted that as Smart Grid develops, utilities can look to other industries to examine practices that may be applicable in the Smart Grid context.

Other commenters cautioned that one process should not be mandated at this point in time to avoid stifling innovation. CEA at 5; EEI at 24; FPL at 7-8 (noting, however, that utilities need the opportunity to determine what mechanisms are best); Idaho Power at 7. EEI recommended the use of FCC rules governing access to CPNI as a model, noting that these rules offer useful mechanisms for customers to make informed choices about access to and use of CPNI data. EEI at 23.

A number of commenters acknowledged that flexibility is particularly important given that in some cases, access to data will be made by the utility with consumer consent, and in other cases, access will be granted directly from consumers. APPA noted that other options in addition to utility practices for providing data could be basic in-home energy displays and more sophisticated displays or home energy network (HAN) energy management systems. APPA noted that security and privacy protocols should be incorporated into each access option. APPA at 11; see also EEI at 24 (referencing the possibility of utility-offered HAN solutions, or solutions offered through open market); EnerNOC at 4 (discussing standard mechanisms such as password protections); NASUCA at 21-23 (discussing the benefits of HAN deployment and noting that privacy protections must take into account future developments like PHEVs and unforeseen devices); Southern at 6; UTC at 13.

Some commenters also gave examples of open market solutions. Tendril stated that its next software release will allow consumers to go to the utility website and see what data is being captured and who has access to it. Consumers can then determine what they want to have happen to that data. This approach offers choices to different people with different thresholds or trade-offs for use of their data. For example, the consumer can save money, but in order to do that, the consumer must allow the vendor to use a reasonable amount of behavioral information, such as when a person is at home and to what temperature the person's thermostat is set. Tendril, PTR at 44-45. Tendril also discussed the interactive privacy controls available on Facebook that can be adjusted over time, so that consumers were aware that they were never locked into a particular privacy setting. Tendril at 6. UTC also mentioned the On-Star program, offered by General Motors, that tracks car performance, speed, fuel consumption, location, routes, and other factors, as well as the Apple iTunes Genius Bar that reviews customer music

[86] Offering a different view, CPower stated that these data sharing practices should be left to customer stakeholder groups and relevant governmental entities in the electric industry rather than other market participants. CPower at 3.

selections and makes suggestions about other music the customer may want to purchase. Both of these allow consumers to give up some measure of privacy by sharing data with a third party in return for the resulting benefits. UTC at 3-4.

Commenters also highlighted the importance of consumer education regarding their privacy and access choices. DRSG stated that for residential customers, clear, simple and straightforward guidance was important, and that the models developed by NIST and FERC, with input from DOE, may be appropriate. See also DTE at 5 (stating that educational materials should be provided to customers, and third parties should be required to provide clear and understandable information to consumers about implications of using their services); Tendril at 6; US Telecom at 2. SCE stated that while customers should have control over access to their data, as well as the scope and duration of that access, utilities could educate consumers about the legal obligations of third parties, the importance of transacting with reputable entities, and possible means of redress for third party misuse of data. SCE at 5. In Silver Spring's view, an explanation of the benefits of disclosure should be provided to the consumer, as well as the disadvantage of opting out. Silver Spring at 6 (further clarifying that utilities should make basic information available directly to the consumer, and that third parties could provide more advanced services). Silver Spring also noted the difficulties in striking the right balance between too little and too much control over privacy choices. The company's multi-tiered, highly granular system of privacy controls was widely criticized as being too complex. DRSG clarified that for commercial and industrial customers, individual contracts would work best, with actual adoption, enforcement taking place at state or utility level.

Question 10: What security architecture provisions should be built into Smart Grid technologies to protect consumer privacy?

Commenters listed certain core requirements that should be required to protect the privacy, integrity and accessibility of energy information. Many noted that current utility cyber controls already help prevent such unauthorized access. Such controls could include data encryption and secure maintenance of encryption keys, network segmentation, the separation of operational and other data from customer data, appropriate controls on employee access to data and employee training on proper data handling, clear authorization procedures for third party access to customer data, authentication of Smart Grid devices and users, intrusion detection and prevention, physical security controls, and auditing procedures, among others. APPA at 12; Avista at 5; BG&E at 4-5; DTE at 5; EEI at 25-26; Elster at 3; Exelon at 4 (suggesting required use of the Federal Information Processing Standards for cryptography); Honeywell at 6 (highlighting the need for a direct consumer interface with the meter); Idaho Power at 7-8; NASUCA at 23 and Oncor at 7; Pepco at 7; Roundtable at 5-6; SCE at 5 (recognizing the efforts of the Advanced Security Acceleration Project for the Smart Grid and a related DOE-sponsored working group that produced AMI and absolute digital encoder ("ADE") security profiles, as well as Smart Energy Profile 2.0); SDG&E at 12-13; Silver Spring at 7 (suggesting use of a 20-year threat model); Southern at 6-7; US Telecom at 3 (suggesting that consumer energy data other than aggregate residential use should travel not over smart meter but through a consumer-chosen interface). SDGE noted that security should be commensurate with the value of the data, and SDG&E and Idaho Power also noted a division of responsibility between utility protection of data on utility assets and consumer protection of data residing in customer assets.

Other commenters stated that Smart Grid technologies can borrow security architectures used by other areas of commerce, such as online banking, internet shopping and wireless communication, which include best practices for data encryption, storage, and anonymization. CPower at 3; DRSG at 7; EnerNOC at 5; Tendril at 6. NASUCA commented that regardless of the architecture structure used, open standard protocols should be vendor neutral. NASUCA at 23. Relatedly, Cisco emphasized the importance of developing technology based on protocols like the Internet Protocol ("IP"), where multi-protocol systems can be run and newer systems are compatible with existing systems so that investment isn't stranded. Cisco, PTR at 87-88; see also Google OSTP comments at 2 (suggesting use of open platforms like the Internet to foster application development). FPL agreed, stating the need to standardize on a common communications layer based on IP so that many technologies and products can interact. FPL also stated that standards development organizations should be leveraged to define common messaging formats to enable the exchange of energy information. FPL at 7. Elster recognized that security architecture must be updated as threats change over time. Elster at 3.

EEI noted that the DOE laboratories have done considerable work on technology modeling for security architecture, and industry could benefit from having access to these resources. Integration and equipment certification at independent laboratories, as well as NIST certification, would be useful in moving forward with security architecture development. EEI at 26. As discussed in response to Question 3, a number of commenters also stated that the NIST Smart Grid standards under development could be used as a framework for determining security architecture for Smart Grid technologies. Commenters emphasized that these technologies should be developed using standards that allow for interoperability and innovation as Smart Grid technologies develop. APPA at 12; CEA at 5; CPower at 3; DRSG at 7; EEI at 26; Exelon at 3-4; FPL at 8; NRECA at 13-14; Tendril at 6; Whirlpool at 4.

Question 11: How can DOE best implement its mission and duties in the Smart Grid while respecting the jurisdiction and expertise of other Federal entities, states and localities?

A number of commenters stated that DOE should defer to state jurisdictions on data access issues, because customer privacy expectations and how they relate to Smart Grid will be considered as Smart Grid is developed within each State. Exelon at 4; Idaho Power at 8-9; UTC at 14. Southern added that while states have the primary jurisdictional role in regulating electric utilities in the provision of retail electric service, DOE should continue its work with the Smart Grid Task Force. Southern at 7. In contrast, a few commenters stated that federal programs and standards would be preferred because standards that differ by state make economies of scale, as in the sale of products nationwide, difficult. See, e.g., Whirlpool at 4. Additional comments on the merits of state versus federal standards are provided in response to Question 8.

Other commenters recognized the importance of state-federal coordination, stating that DOE could help to guide the development of Smart Grid data privacy best practices. CEA at 6; CPower at 4; DRSG at 7; Pepco at 8; SCE at 6; SDG&E at 14; Tendril at 6; Whirlpool at 4. Many of these commenters indicated that while states have important interests in utilities regulation and consumer protection, including privacy interests, it was important to have federal guidance in developing data privacy protocols to avoid multiple, inconsistent rules being applied to Smart Grid. DTE and EEI noted that DOE should ensure that any policies it develops are in concert with existing state laws and regulations, with deference to utility policies and rate structures, to ensure that utilities can meet their obligations in providing service to their customers. DTE at 5; EEI at 27.[87]

Some commenters also believed that DOE could serve a facilitator's role, encouraging dialogue, providing forums, collecting information and providing consumer education on Smart Grid data privacy and other issues. APPA at 12; BG&E at 5 (referencing the Smart Grid Information Clearinghouse that DOE is developing with the Virginia Institute of Technology); CEA at 6; EEI at 27-28; Elster at 3; FPL at 8; Honeywell at 7; NASUCA at 23-24; NRECA at 14; NW Energy, PTR at 74; Oncor at 7; Pepco at 8; SDG&E at 14. These commenters also acknowledged the role of other Federal agencies in developing data privacy protocols, including FERC, NIST, and the FCC. Honeywell stated that DOE should provide guidance to NIST in developing standards that account for data access policies. Honeywell at 7. EnerNOC stated that DOE could help ensure consistency in the development of data privacy standards by funding only activities that conformed to NIST/FERC standards and protocols, and by supporting implementation of the FERC National Action Plan on Demand Response ("FERC NAP-DR") a main component of which are education programs to help consumers understand and accept Smart Grid. EnerNOC at 5; see also DRSG at 7; Honeywell at 7. NRECA also added that DOE should provide leadership in the Administration's cross-departmental Smart Grid subcommittee. NRECA at 14. Other commenters also added that DOE should build on the FERC-NARUC Smart Grid Collaborative, the [NERC] Smart Grid Task Force, and other efforts in creating a national dialogue and avoiding overlapping efforts. APPA at 12; CEA at 6; Tendril at 6; Verizon at 3. Oncor added that DOE could coordinate utility and State viewpoints and represent those views before other agencies and Congress. Oncor at 7.

Honeywell discussed the important of DOE's Smart Grid Investment Grant (SGIG) and Streamlining Departmental Grants Program (SDGP) grant programs, stating that because the DOE funds for these programs will significantly affect Smart Grid architectures, it is imperative that DOE evaluate future grant applications that take into account data accessibility policies and ensure that consumers have access to their data. DOE should also use data accessibility considerations to guide deployments under grants already awarded, to the extent possible. Honeywell at 7 (referencing use of the Smart Grid Information Clearinghouse). See also Pepco at 8; Southern at 7; UTC at 14.

One consumer also suggested that DOE establish an internal entity focused on the ways in which consumers use energy and what policies are necessary to ensure consumer representation as Smart Grid is developed. DRSG at 7.

---

[87] One commenter discussed coordination with specific governmental entities, stating that DOE should fulfill its Smart Grid mission in a manner that complements law enforcement efforts, and that standards should be developed to determine what constitutes a valid request for Smart Grid data. Neustar at 3.

Question 12: When, and through what mechanisms, should authorized agents of Federal, State, or local governments gain access to energy consumption data?

Comments on this issue focused on access to aggregate energy consumption data by Federal, State and local officials for regulatory purposes, access to individual data by law enforcement and other government officials, and other specialized questions of access.

On the issue of access to aggregate data by government officials, a number of commenters agreed that government agencies should have access to data within their respective jurisdictions in order to accomplish policy objectives. BG&E at 5; CPower at 4; DRSG at 8; Elster at 4; Oncor at 8-9; Pepco at 8; TIA at 2. DRSG added that appropriate guidelines should be established for how government agencies may aggregate and use aggregated information, where such information does not include personal information of an individual consumer. These agencies must access energy consumption data in accordance with such established policies and applicable laws. DTE at 5; EEI at 29; Exelon at 4, FPL at 9, Honeywell at 8, SCE at 7; Tendril at 6-7; Xcel at 7; Xcel Reply at 7 (also including non-profits seeking information for energy assistance or conservation purposes). NASUCA added that consumer data released to governmental agencies should remain confidential, with certain exceptions. NASUCA at 24.

On the issue of law enforcement access to data, or government access to individual consumer data, commenters indicated that authorized agents of Federal, State or local governments should be able to gain access to energy consumption data consistent with applicable law. APPA at 13; Avista at 5; EEI at 28; FPL at 9; Idaho Power at 9; NASUCA at 24; Neustar at 1, 3, 5 (stating that properly authorized law enforcement agents could use consumer energy data for legitimate law enforcement purposes, and that no data should be off limits for these purposes); Pepco at 8; SCE at 6-7; SDG&E at 15; Silver Spring at 7-8; Southern at 7; Tendril at 7; UTC at 15; Whirlpool at 4; Xcel at 6. Neustar added that energy consumption data may also be subpoenaed in civil proceedings, consistent with applicable process, and that authorities might consider whether notice to the affected consumer should be required before disclosure. Neustar at 1, 4-5; but see Xcel at 6-7 (refusing attorney subpoena, as opposed to a court order). Xcel also noted that entities administering customer-initiated requests for federal or state energy assistance programs or state public-utility approved conservation programs could access individual data with customer consent, and the customer could also ask Xcel to disclose energy to a third party, as long as the customer was acting with informed consent. Xcel Reply at 6.

Some commenters had more specific comments on this topic based on their own particular circumstances. BOMA clarified that government agents should not have access to building-specific data . BOMA at 2. The Roundtable stated that building owner consent is critical so that energy data may be placed in the proper context, meaning that relevant information such as the age of the building may be provided, and building owners have a chance to review and correct the data before it is provided to government agents. Roundtable at 6.

Question 13: What third parties, if any, should have access to energy information? How should interested third parties be able to gain access to energy consumption data, and what standards, guidelines, or practices might best assist third parties in handling and protecting this data?

Commenters stated that with consumer consent, third party vendors could collect consumer data to share with the particular consumer from whom the data was collected. APPA at 14; CEA at 6; Cleco at 2; CPower at 4; DRSG at 8; DTE, PTR at 86; EEI at 30; EnerNOC at 5-6; FPL at 9; Honeywell at 8; Idaho Power at 9; NASUCA at 24-25; Neustar at 5; NW Energy, PTR at 41, 45; Oncor at 8; Pepco at 9; Roundtable at 7 (discussing consent for the release of building-level data); SCE at 6; SDG&E at 16; Silver Spring at 8; SMUD, PTR at 28, 55-56, 67; Tendril, PTR at 21-22, 26, 33-34, 36, 43-44; Tendril at 7-8; TIA at 2; US Telecom at 1-2; UTC at 15; Verizon at 2; Whirlpool at 4; Xcel at 8; Xcel Reply at 7. APPA and EEI added that third parties should obtain consent in a transparent manner and should also disclose their policies on (or require consumer consent for) sharing data with other parties and explain how the data they collect will be used. APPA at 14; Cleco at 2; EEI at 31; FPL at 9. BOMA also noted that building owners should have access to whole building data on a monthly basis, ideally by fuel type. BOMA at 2.

Commenters noted that Smart Grid information could be used for a variety of purposes, but that the scope of the applications and software that may be developed is as of yet, however, unknown. CO OCC, PTR at 22-23; Tendril, PTR at 75. Commenters suggested a few specific third parties who could access consumer electric consumption data. These parties include those providing predictive maintenance programs to consumers to help them manage their energy use. Tendril, PTR at 75; Whirlpool, PTR at 106-107. In addition, SMUD noted that utilities will be able to segment customers much more than in the past, and there will be a bigger variety of programs to offer customers, for both utilities and third parties. SMUD, PTR at 98. In addition, energy service companies that sell smart devices, such as meters that aren't connected to the Smart Grid, should also be given access. NW Energy, PTR at 70. One commenter stated that state regulators should consider whether release to third parties should be limited to public policy purposes, such as furthering conservation of climate change mitigation goals, facilitating energy assistance, or supporting energy policy advocacy. Xcel Reply at 8.

On the issue of appropriate standards for third party access to and handling of data, Cisco noted that this issue is still an open question. For data that is moved around inside the home, there are a lot of network technologies out there, and all of them have different security systems. We are not at a point in this technology where only one of these systems is the right one. There is a lot of technology to be developed in this area, as well as different systems that may work better in different situations for different purposes. Having the data in a standardized format, and having standardized ways of exchanging information and making sure consumer consent has occurred makes a lot of sense. Beyond that, however, consumer choice should be allowed in order to foster innovation. At some point, Smart Grid technologies may spur a consumer driven market independent of third parties working with utilities, or a hybrid of both. A standard for secured transition of information from one device to another might promote such innovation, but it might be deterred or precluded if we tried to define, today, a standard with one permissible means to achieve this result. Cisco, PTR at 68-69. Honeywell noted that privacy standards and guidelines for medical or financial information could be used as a starting point for establishing guidelines for energy information. Honeywell at 8.

NRECA stressed that because third parties may not be subject to state public utilities commissions or consumer-elected boards of directors like electric cooperatives are, third party data handling requirements and how to impose and enforce those requirements merits further discussion. NRECA at 11-12. Additional comments on third party practices for handling consumer data, including appropriate authorization and certification procedures, are discussed above in response to Question 3.

Liability.

Utilities also commented on the liability of utilities and third party vendors for the improper use of consumer Smart Grid data, stating that as the consumer agrees that data should go upstream to other vendors, those vendors should step into the shoes of the utility in terms of specificity of consent for whatever else may happen with the data, as well as for potential liability. Cleco at 2; EEI at 31; FPL at 9; NASUCA at 17-18; NW Energy, PTR at 40-41, 45; UTC at 9. NASUCA added that consumers should be informed of the appropriate avenues for redress in situations for misuse of data by utilities as well as by third parties. SMUD further noted that the liability issue can be dealt with contractually with the third party vendor. SMUD also referenced legislation is moving forward in California that would make clear that once there is a transfer of Smart Grid data from the utility to the third party, liability shifts to the third party, and California would hold the third party to the same standards as it held the utility. SMUD, PTR at 65-66. This legislation, Senate Bill 1476, was passed on September 29, 2010.

Question 14: What forms of energy information should consumers or third parties have access to?

Commenters responded that authorized third-party vendors could collect specific energy use information with the consent of consumers, for use of the consumer or third parties. Other commenters discussed third party and governmental use of aggregate data.

Many commenters agreed that consumers and authorized third parties should have access to data that pertains to their energy use. BG&E at 6; CEA at 7; CO OCC, PTR at 22-23; CPower at 5; DRSG at 9; DTE at 6; EEI at 34; Elster at 4-5; EnerNOC at 6-7; Exelon at 4; FPL at 10; Honeywell at 8-9; Idaho Power at 9; NASUCA at 26; NRECA at 14-16; Oncor at 9; Pepco at 9; Roundtable at 7 (stating that utilities should provide whole building data to building owners; see also BOMA at 2); SCE at 7; SDG&E at 16; Silver Spring at 8; Southern at 8; Tendril at 8-9; Tendril, PTR at 23, 26, 33-34; TIA at 2; US Telecom at 1-2; UTC at 16-17; Verizon at 2-3; Whirlpool at 5; Xcel at 8-9. Such data would include information generated by the meter, including electricity use by interval. Information corresponding to a customer’s current bill and historical usage information are often already made available, and Smart Grid capabilities may allow for these additional types of data, including real-time demand data, pricing and source generation information, peak demand data and rebate information, demand response signals, and disconnect status. Xcel clarified that providing customers with standard usage data, those data elements provided on a customer’s bill and any other information available to all customers of the same class within that jurisdiction, was part of its traditional service. Providing customers and third parties with non-standard, individualized data is not part of this service, and any release to third parties must contain the consumer's informed consent. Xcel Reply at 8-9. CEA asserted that at this early stage, there should be no unreasonable or artificial caps placed on the amount or types of information that a consumer could request from utilities or retail energy providers. CEA at 7. EEI and UTC cautioned, however, that consumer access to raw data, as opposed to verified billing data, could undercut consumer confidence in their usage data if consumers try to estimate their own energy bills and end up with a value different than that provided on the bill by the utility. EEI at 34; UTC at 17.

Some commenters stressed that decisions about when, whether and in what manner utilities should provide consumers with this information should be made locally by States and retail regulators because of the significant cost implications. APPA at 14-15; Avista at 6; NRECA at 15-16; NASUCA at 26; Southern at 8 (noting that consumers should not have access to information not collected by the utility or not related to their energy use rates). More detailed comments on the provision of real-time data are provided below in response to Question 15.

Commenters also offered examples of the way this energy use information could be used by the consumer. Authorized, third party vendors could collect and provide consumers with information via email on inefficient air conditioners or other appliances or other ways they could save money on their energy bill. Thermostats and appliances that can react to price and load control signals to turn on and off load fairly autonomously could also help consumers lower their energy bills. Tendril, PTR at 22, 26; CO OCC, PTR at 22-23. Consumers could also be measured against their own consumption, week to week, year to year, or some other time frame. Consumers could also be measured against their own set of targets, such as a target to save $50 this month versus last month. Consumers could also be measured against a normalized version of themselves – in other words, similar households in the same area. Such information shows consumers how efficient their houses are on a sliding scale and how houses that use less energy are cutting their energy use, including where the thermostat is set, and then lets consumers decide if they want to use the same energy saving measure with a simple click. Tendril, PTR at 33-34. Smart Grid could also allow the use of predictive maintenance programs to help consumers manage their energy use. Tendril, PTR at 75; Whirlpool, PTR at 106-107. In addition, utilities will be able to segment customers much more than in the past, and there will be a bigger variety of programs to offer customers, for both utilities and third parties. SMUD, PTR at 98. Tendril emphasized that the scope of the applications and software that may be developed is as of yet unknown. Tendril, PTR at 75.

Commenters also noted that some of the means identified to help consumers save energy can be done using low-tech solutions in addition to solutions developed through Smart Grid. These include a method of allowing consumers to go online and compare their energy use to similar households in their area, or using smiley and frowning faces to denote low or high energy use in a bill insert. TechNet, PTR at 33. SMUD, PTR at 35. Though information that the consumer gets a month late in his or her energy bill could also be provided in real time, to the consumer's smart phone or via the web. Tendril, PTR at 36.

On the issue of aggregate data, FPL and EEI noted that only utilities should have access to aggregated information unless they authorize a third party to access it. FPL at 10; EEI at 33-35 (noting cybersecurity concerns). Avista, Roundtable and SCE disagreed, stating that the general public and third parties should have access to aggregated data. Avista at 6; Roundtable at 7; SCE at 6. Xcel noted that releases of even aggregate data must include appropriate security concerns. Xcel at 9; Xcel Reply at 9 (also noting cyber security concerns, as explained in the response to Question 2). In addition, as set forth in response to Question 3, some commenters noted that utilities may also enhance data for their business purposes, and only authorized third parties should have access to such data, whether aggregate or individualized. EEI at 33-34; FPL at 10; SDG&E at 3, fn 3.

Question 15: What types of personal energy information should consumers have access to in real-time, or near real-time?

Many commenters agreed that consumers should have access to their energy consumption data in real-time. Avista at 6; CEA at 7; CO OCC, PTR at 22-24; CPower at 5; DRSG at 9-10; Elster at 4; EnerNOC at 7; Google at 1; Honeywell at 9; Joint Center at 9; NASUCA at 27-28; Oncor at 9 (though noting that such data would be provided by a device that interacts with a customer's meter, rather than from a centralized data access point); Roundtable at 7; SDG&E at 16-17; Silver Spring at 8; Tendril at 9; Whirlpool, PTR at 18-19; Whirlpool at 5. Such data would include data on how much energy their air conditioners or appliances were using, in real-time so that consumers could choose to save energy, buy more efficient appliances, and lower their energy bills. Whirlpool, PTR at 18-19. Such data is particularly important if time of use pricing or critical peak pricing is used, so that consumers know when to turn down their air conditioning, heat, water heater or other appliance, and whether their appliances are inefficient and could be replaced. CO OCC, PTR at 22-24.

EEI and others asserted that the cost of real-time data may not be justified, that such data is of limited utility for most consumers, and that the real beneficiaries may be third parties who wish to pass the cost on to consumers. If policymakers decide that real-time access is needed, they should consider the beneficiaries of such access in determining who should pay for that access. EEI at 36; EEI Reply at 3. NRECA agreed that real-time data may not significantly benefit most consumers, and that issues of metering system capabilities, data quality, and cost must be considered. NRECA at 16. Unless a utility uses dynamic pricing, there may be no compelling consumer benefit from real-time energy use data. And it should not be assumed that real-time prices are needed to support home energy services. Id. at 17. *See also* BG&E at 6 (noting that utilities would likely provide day old data because of current technological limitations and the need of utility to validate data; real-time data is currently available on in-home displays.)

Other commenters agreed that provision of real-time data must be reliable and cost-effective before it is delivered to consumers. FPL at 10; Idaho Power at 9-10; Pepco at 9-10; Xcel at 9-10 (all noting that other alternatives, such as devices that can interact with existing meters, should also be considered); UTC at 17-18. APPA stated that whether the utility provides the data in real time may depend on its business plan. Provision of real-time data may be cost-effective to support time-differentiated rates and demand response rates. In some cases, however, the utility may need to provide consumers data only on a daily or weekly basis to achieve the utility's peak shaving goals, but in those cases consumers could partner with a third party to get real time data. APPA at 15-16. See also SCE at 7 and Southern at 8. Similar to comments made above in response to Question 15, Xcel distinguished between raw data and processed, enhanced usage information. The former was relatively easy to provide, while making the latter available would require an evaluation of the accompanying costs. Xcel Reply at 10 (also noting that other devices like hand-held power meters might offer an affordable approach).

Commenters also discussed real-time data other than usage data that should be make available to consumers. Some stated that price information should be communicated to consumers, though some indicated that day-ahead forecasts would suffice. EEI at 35; Elster at 4; NASUCA at 27-28; SDG&E at 17; Silver Spring at 8; SCE at 7 (while noting that tariff structures may distort price information). Silver Spring stated that consumers are more likely to want to know when to avoid high energy prices than how much energy they are consuming at a given time. Tendril stated that real-time generation source information (including emissions profiles) and demand response event notification should also be provided in real-time. Tendril at 9. DTE noted that pilot projects underway, including DTE's SmartCurrents project and the Pacific Northwest SmartGrid Pilot, could provide information about the types of energy information consumers want, and also the costs of providing that information. Such pilot programs will also help identify the feasibility, costs, and security requirements associated with providing real-time or near real-time data to consumers. DTE at 6.

Third party vendors could also provide those consumers who have opted in with information about how to save money, based on the specific information collected by the vendors. Tendril, PTR at 22. In addition, if the consumer wants to lower energy bills or become greener or be more energy efficient than the neighbors, thermostats and appliances that can react to price and load control signals to turn on and off load fairly autonomously are important, because the consumer is not always going t be present to manage these things. Consumers can set up a rule that says if the price of electricity goes above X, change my thermostat to Y. If consumers have to do this manually every time, they won't interact with the system. Tendril, PTR at 26-28. Utilities could also interact with consumers who have opted-in, to do demand response and load leveling. Whirlpool, PTR at 46-47. See also SMUD, PTR at 39 (referencing third party programs and the utility as the honest broker between third-parties and consumers).

The UTC noted that while giving consumers the data to optimize their own use is important, utilities also need this data to help the customer optimize the grid for everyone. For example, if two electric cars are plugged in, the charge to each would alternate. Such optimization will avoid the need for new infrastructure and the costs associated with it that all consumers will bear. UTC, PTR at 77-78. In response, Tendril commented (and the UTC agreed) that such behavior should be the consumer's choice, and there should be a clear and tangible consumer benefit. Incentive structures are needed to encourage behavior that benefits the utility and grid reliability, such as trade-offs between charging the car and cooling the house. Tendril, PTR at 79-80.

Question 16: What steps have the states taken to implement Smart Grid privacy, data collection, and third party use of information policies?

According to commenters, a number of states have begun to implement Smart Grid data privacy, collection, and third party use policies. The legislatures of California and Texas, for example, have begun to address these issues through laws with which utilities must comply. APPA at 10, 16; Pepco at 10.

More specifically, legislation is moving forward in California that would shift liability to the third party vendor once there is a transfer of Smart Grid data from the utility to the third party. The third party would be held to the same standards as it held the utility. SMUD, PTR at 65-66. (This legislation, Senate Bill 1476, was passed on September 29, 2010.) The California Public Utilities Commission ("CPUC") has also drafted its "Order Instituting Rulemaking to Consider Smart Grid Technologies Pursuant to Federal Legislation and on the Commission's own Motion to Actively Guide Policy in California's Development of a Smart Grid System". CPower at 5; DRSG at 10; Tendril at 9; SCE at 8-9; SDG&E at 17-18 (noting that the CPUC explicitly required investor-owned utilities to provide authorized third parties with access to a customer's real-time or near real-time usage information no later than the end of 2011). Where advanced metering is involved, Texas requires utilities to use industry standards in providing secure access to customer data, as well as to provide customers with ready access to their energy use data. NASUCA at 30; Pepco at 14-15 (also discussing other Smart Grid efforts in California, Colorado and Maine). Colorado has begun a proceeding to investigate security and privacy concerns in the deployment of Smart Grid, Docket 091-593EG "In the matter of the investigation of security and privacy concerns regarding the deployment of smart-grid technology." CPower at 5; DRSG at 10; Tendril at 9. In Michigan, the Michigan Public Service Commission ("MPSC") is creating a collaborative project to discuss issues of privacy, data collection and third party data usage. DTE at 4, 6. Policies and practices implemented by the State of Florida preclude utilities from releasing customer-specific data to a third party without customer consent, except as otherwise provided by Florida or Federal law, or in response to a subpoena. FPL at 11.The Louisiana Public Service Commission also issued a General Order implementing its "Rule for Approval and Cost Recover for Advanced Metering Systems and Demand Response Programs", which contains provisions on the release of consumer data. Cleco at 1, 3.

States are also using more generally applicable laws to address data privacy issues associated with the Smart Grid. For example, states such as California, Pennsylvania and Texas have required consumer consent before utilities can release consumer information to a third party even in the absence of Smart Grid specific legislation. Texas and California also specifically prohibit the sale of customer specific data. NASUCA at 29-30; Oncor at 10-11, Pepco at 11-13 (discussing release of information requirements in the District of Columbia, Maryland, New Jersey, and Delaware); SCE at 8; SDG&E at 17. The District of Columbia limits the use of customer information to the use for which the information was originally acquired unless the customer consents in writing. Id. MPSC rules governing electric and gas utilities generally, as well as Michigan's identity theft protection Act and Social Security Number Privacy Act would also be relevant in the Smart Grid context. DTE at 4, 6. States have also implemented consumer protections against unfair and deceptive practices and privacy protections for customer data in other contexts. Anti-hacking statutes prohibit unauthorized access to computers, including smart meters. Security breach notification laws that require notification of unauthorized access to personally identifiable information have also been enacted in 45 states, the District of Columbia, Puerto Rico and the U.S. Virgin Islands. EEI at 36-37; Pepco at 11. Southern also commented that the existing regulatory framework is likely appropriate to develop protections for customer data generated through Smart Grid and AMI deployment. Southern at 9.

Neustar noted that states don't appear to have addressed significantly the potential Smart Grid data needs of law enforcement, and that to address this issue, states could look to federal statutes governing privacy of communications data (i.e., the Stored Communications Act). Neustar at 3.

Question 17: What steps have investor owned electric utilities, municipalities, public power entities, and electric cooperatives taken to implement Smart Grid privacy, data collection and third party use of information policies?

A number of commenters indicated that utilities have a long history of protecting customer privacy and have developed, or are working to develop, Smart Grid data privacy policies. APPA at 6; Avista at 4-5; BG&E at 6; DTE at 6-7; EEI at 37-38; EEI Reply at 7-8; FPL at 11 (noting that FPL's current policies to protect customer data and provide for third party access will continue to be used for data generated through the Smart Grid); Idaho Power at 10 and Southern at 9 (also noting that current policies protect customer specific energy data, but acknowledging that these policies may be updated as Smart Grid evolves); NRECA at 17-18; SCE at 8-9; Xcel at 10; Xcel Reply at 10. DTE explained further that utilities are looking at their privacy policies, doing internal assessments, and looking at benchmarking. DTE also noted that as we move into the future of Smart Grid, utilities are determining how their data privacy and confidentiality policies need to change for the new information that would be collected through the Smart Grid. There are no hard and fast rules currently on privacy, and utilities are taking this issue very seriously. DTE Energy, PTR at 86. DTE Energy also noted that it has worked closely with EEI in drafting guidelines on consumer data access and policy, and that many utilities and others are involved in that process. DTE Energy, PTR at 86. Xcel emphasized that its Director of Data Privacy and Customer Data Taskforce monitor and address emerging concerns, and that Xcel will continue to update its policies to reflect evolving customer needs and regulatory requirements. Xcel ultimately intends to file a tariff outlining customer data protections and third party access limitations. Xcel Reply at 10. APPA also noted many that utilities are participating in the NIST and NERC processes to develop Smart Grid data privacy policies, which are discussed above in more detail in response to Question 3.

In addition to the development of data-privacy plans and policies, utilities are taking other steps to protect customer data. These steps could include use of the utility's own proprietary fiber installation to reduce the risk of unauthorized breaches or contracting for wireless networks that use secure transfer protocols. APPA at 16-17; Oncor at 11 (referencing Oncor's secure data provisioning process); SCE at 9 (noting that SCE designed its AMI to include security architectures to safeguard consumer information). Utilities are also implementing pilot projects that include data security elements. Con-Edison has developed a demonstration project involving 1500 customers, 1200 of whom will have web service applications to display energy usage, and 300 of whom will have a Home Area Network (HAN) installed by one of three vendors. As part of this project, Con-Edison is reviewing security measures of each HAN provider to protect the privacy of energy usage information, and requiring that all vendors have SAS70 certification. Non-disclosure agreements and other contractual safeguards are also in place, and meter usage information is shared with these vendors through a secure file transfer protocol ("FTP"). EEI at 38-39. NW Energy is also engaged in a demonstration project, the Pacific Northwest Smart Grid Pilot, which focuses on distribution infrastructure to enable applications and on investment in technology areas that won't become stranded. NW Energy, PTR at 36-37, 101. In an overview of the pilot, NW Energy indicated that it would promote interoperability and cyber security. NW Energy Pilot Overview Presentation at 7. Many utilities noted that they are also engaged in consumer education efforts concerning data privacy. APPA at 16-17; NRECA at 18-19; SCE at 9, Xcel at 10.

Question 18: Should DOE consider consumer data accessibility policies when evaluating future Smart Grid grant applications?

Commenters who addressed this issue were split on whether DOE should consider consumer data accessibility policies when evaluating future Smart Grid applications.

Many commenters believed that it was important for DOE to consider data-accessibility policies when evaluating future Smart Grid grant applications. APPA at 7; Avista at 7; BG&E at 6; CEA at 7; CPower at 5; DRSG at 11; DTE at 7; Elster at 5 (noting that DOE review of applications already contains a number of assessments, including of cybersecurity); EnerNOC at 8; Honeywell at 10; Idaho Power at 10; NASUCA at 31; NRECA at 19; Pepco at 16; Roundtable at 8; SCE at 10 and Southern at 9 (both noting that DOE should give appropriate consideration to existing state requirements); SDG&E at 20; Tendril at 10; Whirlpool at 6; Xcel at 11; Xcel Reply at 10-11. These commenters stated that it is important to consider data accessibility and privacy protection at the forefront of Smart Grid development. DOE has an interest in maintaining consumer privacy as well as data access and can significantly advance issues of consumer information privacy by making those issues an important part of grant applications. Such considerations should also be central to a review of applications because of the importance of the consumer's right to individual data and the right of certain entities, such as governmental entities and utilities, to aggregate data generated through the Smart Grid. APPA clarified, however, that DOE should not require specific data accessibility provisions but should instead evaluate whether the applicant's policies are suitable. Tendril noted that it was important to develop consistent criteria for the evaluation of accessibility and privacy policies in applications. And in contrast to NRECA, Idaho Power stated that DOE should give preference to applications that demonstrate appropriate consideration and protection of customer privacy and individual energy consumption data.

A number of other commenters believed that DOE should not consider data-accessibility policies when evaluating Smart Grid applications. EEI at 39; Exelon at 5; FPL at 11; NRECA at 19. These commenters indicated that because Smart Grid technologies are still evolving, consideration of data-access policies would be premature and cause needless delay in the consideration of applications and the development of Smart Grid. State privacy policies are also already in place to protect consumers. NRECA further stated that applications for Smart Grid projects that do not address data accessibility should not receive a lower preference for funding if they do not reach the end consumer. Applications for projects to develop consumer-end technologies that do include consumer data access policies should also not be given a higher preference.

One commenter took a middle-ground approach, arguing that data access policies should be considered only to the extent required by applicable Federal and State law, unless the grant relates to consumer use of data as part of a research and development project. Oncor at 11.

GLOSSARY

Advanced Metering Infrastructure (AMI): Refers to systems that measure, collect and analyze energy usage and interact with advanced devices such as electricity or gas meters, through various communication media either on request (on-demand) or on pre-defined schedules. AMI differs from traditional Automatic Meter Reading (AMR) in that it enables two-way communications with the meter.

Customer-specific usage data (CEUD): Includes all data specific to an individual customer's energy use, including at a minimum individual energy use by time interval.

Customer proprietary network information (CPNI): Information that telecommunications services such as local, long distance, and wireless telephone companies acquire about their subscribers, including services used and the amount and type of usage.

File transfer protocol (FTP): A standard network protocol used to copy a file from one host to another over the Internet or a similar network. FTP utilizes user-based password authentication or anonymous user access.

Home Area Network (HAN): A residential local area network used for communication between digital devices typically deployed in the home, usually a small number of personal computers and accessories, such as printers and mobile computing devices.

LEED certification: LEED stands for Leadership in Energy and Environmental Design and is an internationally-recognized green building certification system. LEED certification is intended to demonstrate that a building or community was designed and built using strategies intended to improve performance in energy savings, water efficiency, carbon dioxide emissions reduction, and other similar metrics.

Machine-readable format: Format of presenting data that can be read by a computer.

Operational data: Includes data related to the operation of electric utility systems that is not customer-specific, but includes aggregated customer energy usage data.

Personally identifiable data (PII): Includes at least utility customers' names and any personal identifiers such as social security numbers, home addresses (including both service addresses and mailing addresses if these differ), telephone numbers, and payment history or any credit card or bank account numbers provided to the utility.

Privacy Impact Assessment (PIA): Assessment required by the E-Government Act of 2002, Public Law 107-347, before an agency develops or procures information technology that collects, maintains, or disseminates information in an identifiable form or initiates a new collection of information that will be collected, maintained, or disseminated using information technology and includes any information in an identifiable form permitting the physical or online contacting of a specific individual. PIAs must address: what information is to be collected; why the information is being collected; the intended use of the agency of the information; with whom the information will be shared; what notice or opportunities for consent would be provided to individuals regarding what information is collected and how that information is shared; how the information will be secured; and whether a system of records is being created under section 552a of title 5, United States Code (commonly referred to as the "Privacy Act").

Raw data: Energy usage data that is not formatted or processed.

LIST OF ACRONYMS

AICPA: American Institute of CPAs (Certified Public Accountants)
APEC: Asia-Pacific Economic Cooperation
APPA: American Public Power Association
BOMA: Building Owners and Managers Association
CEA: Consumer Electronics Association
CO OCC: Office of Consumer Council, Colorado Department of Regulatory Agencies
DHS: Department of Homeland Security
DOE: Department of Energy
DRSG: Demand Response Smart Grid Coalition
EEI: Edison Electric Institute
FCC: Federal Communications Commission
FERC NAP-DR: Federal Energy Regulatory Commission National Action Plan on Demand Response
FIPPs: Fair Information Practice Principles
FPL: Florida Power and Light
FTC: Federal Trade Commission
GAPP: Generally Accepted Privacy Principles
HUD: Department of Housing and Urban Development
NARUC: National Association of Regulatory Commissioners
NASUCA: National Association of State Utility Consumer Advocates
NERC: North American Electric Reliability Corporation
NIST: National Institute of Standards and Technology
NRECA: National Rural Electric Cooperative Association
OECD: Organization of Economic Co-operation and Development
PUC: Public Utilities Commission
PTR: Data Privacy Public Meeting Transcript
RFI: Request for Information
SCE: Southern California Edison
SDG&E: San Diego Gas & Electric
SDGP: Streamlining Departmental Grants Program, DOE Program
SGIG: Smart Grid Investment Grant. DOE Program
SGIP-CSWG: Smart Grid Interoperability Panel Cyber Security Working Group
SMUD: Sacramento Municipal Utility District
TIA: Telecommunications Industry Association
UTC: Utilities Telecom Council