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August 14, 2012

FORTISBC INC ADVANCED METERING INFRASTRUCTURE CPCN
EXHIBIT A2-3

Mr. Dennis Swanson
Director, Regulatory Affairs
Regulatory Affairs Department
FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna, BC V17 7V7

Dear Mr. Swanson:

Re: FortisBC Inc.
Application for a Certificate of Public Convenience and Necessity
for the Advanced Metering Infrastructure Project

Commission staff submits the following document for the record in this proceeding:

Case Study of Smart Meter System Deployment.

Yours truly,

Erica Hamilton

/elm
Enclosure
cc: Registered Interveners

DRA
DIVISION OF RATEPAYER ADVOCATES

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.

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Case Study of Smart Meter System Deployment

Recommendations for Ensuring Ratepayer Benefits

by

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March 2012

Table of Contents

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 contains confidential data which is blacked out 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

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[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 (PVRR) in "societal" costs and benefits, though these societal costs and benefits were not

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[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.

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	-$1,195.9	$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;

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[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:

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[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	$ 187.3	$ 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 those operational capital benefits was related to the avoided cost of electromechanical meters,

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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.

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. SCE's 2012 GRC testimony indicates that they are claiming a meter benefit of $8.5 million for

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[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.

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 reduced by $32.3 million for "SmartConnect" benefits.[44] The 2013 estimated meter reading

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[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).

[44] A.10-11-015, SCE-4, Volume 2, Figure IV-10, p.130 (mimeo).

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]

[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 $900 million 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	1,071.2	559.5	176.7	173.5			1,980.8
Conservation effect					811.1		933.2
TDBU Deferred Capital	105.6					39.6	145.2
Measurement & evaluation						12.4	12.4
Program benefit	1,176.8	559.5	176.7	173.5	811.1	52.0	2,949.6

*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 $46.4, $12.7, and $12.8 million 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 $490 million, or 68%, in reduced benefits.[55]

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[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

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[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.

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[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;

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[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 program. D.09-08-027 also included certain other costs (mainly pilot projects, measurement

[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.

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

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[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 not all, this was due to changes in key aspects of the adopted programs. For instance, the

[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.

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 significantly delayed because the communications protocol, Smart Energy Profile (SEP) 2.0 on

[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.

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

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[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 $1 billion 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

[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 $980 million. 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.

many proceedings and 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.

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[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.