SOUTHERN CALIFORNIA
EDISON
An *EDISON INTERNATIONAL* Company

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October 22, 2004

Docket Clerk
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102

RE: R.02-06-001 – Advanced Metering, Demand Response and Dynamic Pricing OIR

Dear Docket Clerk:

Enclosed for filing with the Commission are the original and five copies of the **SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PRELIMINARY ANALYSIS OF ADVANCED METERING INFRASTRUCTURE BUSINESS CASE** in the above-referenced proceeding.

We request that a copy of this document be file-stamped and returned for our records. A self-addressed, stamped envelope is enclosed for your convenience.

Your courtesy in this matter is appreciated.

Very truly yours,

J. Hasbrouck

Jennifer R. Hasbrouck

JRH:LW042310011.doc
Enclosures

cc: All Parties of Record in R.02-06-001
(U 338-E)

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing.	R.02-06-001 (Filed June 6, 2002)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PRELIMINARY ANALYSIS OF ADVANCED METERING INFRASTRUCTURE BUSINESS CASE

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Dated: October 22, 2004

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing.	R.02-06-001 (Filed June 6, 2002)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PRELIMINARY ANALYSIS OF ADVANCED METERING INFRASTRUCTURE BUSINESS CASE

In accordance with the directives of the Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure issued on July 21, 2004 (Ruling) and the extension of time granted on October 7, 2004, Southern California Edison Company (SCE) hereby submits its preliminary analysis for implementation of advanced metering infrastructure (AMI) for review by the California Public Utilities Commission (Commission).

SCE has organized its preliminary analysis into four volumes. Volume 1 focuses on SCE's business vision and management philosophy, preliminary results, and overarching policy considerations. In Volume 2, SCE discusses its approach, including SCE's business-as-usual case, as well as its general assumptions on technology, demand response, rate design and bill impact, and financial implications. SCE further provides in Volume 2 its general risk assessment concerning existing uncertainties. Volume 3 sets forth SCE's preliminary analysis of all of the full deployment business case scenarios on a scenario-by-scenario basis and a preliminary analysis of the revenue requirement. Similarly, in Volume 4, SCE presents its preliminary analysis for the partial deployment scenarios, as well as a preliminary revenue requirement.

SCE's preliminary analysis attempts to address each of the requirements of the Ruling's analytical framework, including performing the analysis for the numerous required scenarios. However, given the sheer volume of scenarios, cost categories, and other requirements, in combination with the comparatively short timeframe within which to complete this analysis, SCE anticipates that there could be a number of changes and refinements to this analysis when the final application is submitted. As such, SCE submits this preliminary analysis for the Commission's preliminary review.

Respectfully submitted,

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October 22, 2004

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of **SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PRELIMINARY ANALYSIS OF ADVANCED METERING INFRASTRUCTURE BUSINESS CASE** on all parties identified on the attached service list(s).

Service was effected by one or more means indicated below:

☑ Placing the copies in properly addressed sealed envelopes and depositing such envelopes in the United States mail with first-class postage prepaid (Via First Class Mail):

- ☐ To all parties, or
- ☑ To those parties without e-mail addresses or whose e-mails are returned as undeliverable;

☐ Placing the copies in sealed envelopes and causing such envelopes to be delivered by hand or by overnight courier to the offices of the Commission or the other addressee(s);

☑ Transmitting the copies via e-mail to all parties who have provided an address.

Executed this 22nd day of October, 2004, at Rosemead, California.

M Rizvi

Meraj Rizvi
Project Analyst
SOUTHERN CALIFORNIA EDISON COMPANY

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Proceeding No.: R.02-06-001
Document No.: SCE-1

SOUTHERN CALIFORNIA
EDISON

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(U 338-E)

Advanced Metering Infrastructure Business Case Preliminary Analysis

Volume 1 – Vision Statement, Summary of Preliminary Analysis, and Policy Considerations

Before the
Public Utilities Commission of the State of California

Rosemead, California
October 22, 2004

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PRELIMINARY ANALYSIS OF ADVANCED METERING INFRASTRUCTURE BUSINESS CASE

Table of Contents

I.

INTRODUCTION

The purpose of Volume 1 is to describe our underlying management philosophy and business vision, plus overarching policy considerations that will guide any deployment of Advanced Metering Infrastructure (AMI), as required by the Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Framework for Advanced Metering Infrastructure issued on July 21, 2004 (Ruling). In Section II of this volume, we describe the business vision that helped shape our analysis of the costs and benefits associated with a full or partial deployment of AMI. Consistent with the Ruling, we also address our view of expected regulatory decisions and expectations of the future business and financial environment, as well as the potential large scale deployment risks that will have a fundamental bearing on the costs and benefits of AMI. Equally important as those items identified in the Ruling, we discuss in our business vision the expected operational and financial impacts that a wide-scale deployment of AMI will have on our customers during the Ruling's sixteen-year analysis period.

In Section III, we set forth the preliminary results of our analysis to date. In this section, we summarize the total costs, total benefits, and net present value of each of the twenty-three unique business case scenarios that we have preliminarily analyzed and described in detail in Volumes 3 (full deployment) and 4 (partial deployment). This section also provides our observations on the results of the cost-benefit analysis as related to the potential for the deployment of AMI.

Section IV of this volume sets forth our overarching policy considerations regarding the deployment of AMI. Specifically, this section discusses what events need to occur for AMI to be successful, including necessary policies to ensure that reliable demand response benefits materialize and that significant constraints and uncertainties are resolved.

II.

SCE'S MANAGEMENT PHILOSOPHY AND BUSINESS VISION CONCERNING THE ROLE OF ADVANCED METERING INFRASTRUCTURE

In the Ruling, the Commission ordered each utility to describe its underlying management philosophy or business vision used to develop its AMI specifications and approach, including a discussion of how key market factors, regulatory constraints, or internal business constraints shaped or affected the development of its AMI business case.[1]

The underlying management philosophy that has helped shape our analysis of AMI is consistent with the management philosophy and vision that guide our investment decisions in other areas of the business, namely, *we will pursue investments that are demonstrated to enhance value for our customers, given the likely costs and benefits of the project and in relation to other investment opportunities*. This overarching philosophy and vision also drives our decisions to adopt new technology or processes when it makes economic sense to do so and is beneficial to customers. Thus, the decision of when to invest in AMI technology necessarily involves assessing the impact on our customers and determining whether investing in AMI at this time is in our customers' best interest or whether an AMI investment in the future or on a different scale may be more beneficial to them. This management philosophy and business vision has shaped our

[1] Ruling, p. 3 ("The analysis the utilities will perform is crucial to the Commission's understanding of the tradeoffs made by the utilities in developing their functional AMI specifications that underlie the benefit cost analysis. In order to enhance this understanding, the utilities should describe the underlying management philosophy or business vision used to develop its functional specifications and approach. Specifically, we are interested in a discussion from each utility of how key market factors, regulatory constraints, or internal business constraints shaped or affected the development of its AMI specifications and cost benefits estimates. ").

preliminary analysis of AMI to date and will certainly continue to influence the development of our AMI strategy and proposal.

In concert with this management philosophy, there are three important fundamental principles that should help guide the evaluation of whether AMI and price-induced demand response make sense for our customers: (1) the program must be cost effective and deliver benefits to customers, (2) the dynamic pricing rate structures must be based on actual costs or prices prevailing in a functioning and appropriate market, and (3) the program should ideally allow for customers to make choices among tariffs.

A. SCE Pursues Investments When They Are Cost Effective and Deliver Benefits To Our Customers

We are in a new age of information and technology which offers great promise in many areas of our business. We know from the dot-com boom/bust cycle that there are many more ideas than profitable ventures. The pace of change is rapid and the question of upgrading from one generation of technology to the next is how many generations of technological improvements should pass before making a change. We have and continue to make cost-effective improvements and upgrades in many areas, including metering.

AMI couples new technology with the benefit from peak load reductions. For years, we have relied on cost-effective reliability-based demand response programs[2] to serve an important role in meeting our customers' capacity needs. We are confident that in time, cost-effective and reliable dynamic pricing[3] and

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[2] By "reliability-based demand response," SCE refers to demand curtailment programs that do not have a price-responsive element and instead are activated upon system emergency, such as the interruptible programs.

[3] By "dynamic pricing," SCE refers to tariffs that enable electric customers to respond to a signal of actual costs or market prices, such as time-of-use or critical peak pricing.

market/economic-triggered demand response programs[4] will also play an important role in balancing California's electricity supply/demand equation. We believe that cost-effective demand response will be a crucial element in an optimal procurement portfolio.

1. SCE Pursues New Technology and Processes that Provide Increased Operational Efficiency

SCE constantly assesses the potential for improving operational efficiency and evaluates new processes and technologies that have demonstrated the ability to deliver benefits to our customers through enhanced services or lower costs. We are a leader in utilizing automated processes and adopting technology where it is economic to do so based on operational efficiencies or process improvements. Today, we already read more than 500,000 meters remotely through our Automated Meter Reading (AMR) program, which targets those meters that are hardest to access and most expensive to read. We also have a long and extremely successful history of developing automated load control programs, such as the highly successful air-conditioner load control program, which continues to deliver highly-reliable and cost-effective demand response.[5] Moreover, we have helped innovate new uses for technology to improve demand response programs, such as testing and supporting the development of smart thermostats and the "energy orb" to provide pricing information to our customers.[6]

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[4] By "market/economic-triggered demand response," SCE refers to direct load control and load curtailment programs that can be activated in response to market prices, such as the demand bidding program.

[5] We previously proposed a major expansion of our successful air conditioner cycling load control program in the Long-Term Procurement Plan submitted in R.04-04-003.

[6] *See* SCE's Demand Response Program Proposals for 2005-2008, submitted in R.02-06-001 on October 15, 2004.

In addition, we have invested (and continue to invest) in highly-effective automated systems that help system operators better understand load and demand requirements. SCE continues to improve automation and data communications for its substation operations with Intelligent Electronic Devices (IEDs) that communicate through a Local Area Network to our Supervisory Control and Data Acquisition (SCADA) System. This modern protection and control equipment provides remote, self monitoring control of all substation functions and identifies potential problems and allows a quick response to reliability events.[7] We have already invested in highly effective outage management and transformer load management systems that are delivering real operational benefits to our customers. As these investments show, consistent with our management philosophy, we embrace technology when it makes sense to do so operationally and when it can reduce costs and provide real value to our customers. Having already made investments in these successful operational systems, we are already reaping the benefits that these systems deliver and thus, any investment in AMI will not provide any significant value for these types of operational benefits.

We recognize, as do the Commission and other parties to this proceeding, that technological innovation is a constant and never-ending cycle. We also recognize that economic efficiency requires flexibility to adopt technological changes as they occur, as well as the careful consideration of the optimal time to invest. Thus, an essential question of this proceeding is whether a large-scale investment in the AMI technology of today will maximize ratepayer benefit or will such investment now cost more to ratepayers due to today's less certain technology and the lost opportunity to capitalize on improved or less expensive technology in

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[7] Among the many types of automation and sophisticated electronic equipment for our substations and operations network are satellite communications for substation data collection and remote system control in areas where conventional methods of communication are not available or are too costly.

the future. We understand that there are promising technological advancements on the horizon and thus, are hopeful that with time, AMI will prove to be a valuable investment for our ratepayers.

2. Demand Response Resources Must Be Cost Effective in Relation to Other Resources

The Commission has endorsed the multi-agency "Vision of Demand Response,"[8] which, in several important respects, mirrors SCE's own business vision and philosophy concerning the proper role of AMI. The preamble to the Vision states:

> "[t]his vision … should be read in the context of maximizing the efficient use of resources, while maintaining the economic vitality of businesses in the state, as well as the health, welfare, and comfort of residential electricity users."[9]

This initial statement is essential to developing an overall policy concerning demand response in California, as the focus is on attaining the optimal mix of resources, not simply promoting one resource over another. The Vision importantly recognizes that the highest attainable level of demand response may not be the most desirable if it results in the inefficient use of resources, harms the state's businesses, and/or adversely impacts the comfort and well-being of residential customers. We agree that demand response should not come at the cost of unreasonable decreases in customer comfort and well-being or a disproportionate impact on certain customer segments. We also agree with the Vision's notion that "cost-effective" may not equal "least cost" and that ultimately, the goal should be the most efficient use of resources.

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8 D.03-06-036, Attachment A, "California Demand Response: A Vision of the Future."

9 *Id.,* p. 1.

The Vision's preamble further states:

> "demand response is one resource among many that may be procured by utilities on behalf of their electric customers. We also seek to make the most cost-effective investments from an overall societal perspective."[10]

Again, this is a key recognition that although demand response shows great promise, it is just one piece of the puzzle in solving California's electricity supply and demand problems. It is important that policy-makers recognize this fact and balance the appropriate level of price-induced demand response with parallel efforts (including, for example, demand reductions from energy efficiency measures, advanced load control, *etc.* and supply-side resources such as new generation, including distributed generation, renewables, *etc.*) so that the most efficient mix of these resources is attained.

SCE's own management philosophy is allied with these elements of the multi-agency Vision, in that we believe that cost-effective demand response does have an important role among the resource options, and that the costs and benefits of demand response and AMI must be evaluated in comparison to the other resources. However, the Commission, Agencies, and the utilities will need to address a number of important policy considerations, as discussed below in Section IV.

Our business vision regarding AMI takes a comprehensive view of demand response versus other resource options. Although demand response offers the potential to reduce peak load, the fact remains that demand response from time-differentiated rates ultimately relies on customer behavior. This "behavioral" aspect makes dynamic pricing demand response more uncertain than other resource

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[10] *Id.*

options, including, among others, supply-side resources, permanent installations of energy efficient equipment targeted at reducing peak consumption, and dispatchable programs such as advanced load control. Simply put, these other resources are generally more permanent and have much greater reliability over the long term than price-responsive demand response resources, which continue to be subject to economic, political and behavioral changes.[11]

The role and success of other resource options, as well as the overall market, may directly affect the economics of whether AMI is the right investment to make for our customers at this time. For example, major regulatory changes to the status of direct access, community choice aggregation, or the introduction of a core/non-core market structure could completely alter the assumptions of how many customers would continue to be utility customers subject to time-differentiated rates, especially if higher rates were required to fund the cost of AMI. This is an important issue because non-utility customers will be subject to the generation pricing of their city or energy supplier which has no obligation to offer dynamic electricity pricing structures. In addition, major changes in the wholesale electricity market, including the role of the Resource Adequacy Requirement, will directly influence the cost effectiveness of AMI.[12]

B. Dynamic Pricing Rates Must Be Cost or Market-Based

The success of AMI relies on benefits from demand response achieved through dynamic pricing. Assessing the value of these benefits requires the

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[11] For example, during the 2000-2001 energy crisis, customers responded to the crisis by reducing their electrical usage, but gradually, these reductions have waned as customers return to their old usage patterns. Reductions from customer behavior, as opposed to load control or permanent energy efficiency equipment, will always be less predictable and reliable and will take continual customer education and marketing to keep informing and reminding customers of the desired behavior.

[12] The development of a functional energy market is an important unknown that must be resolved before AMI can be successful. *See* Volume 2, Section IV.D.

consideration of whether this type of resource will help create an efficient market, lower the peak market prices and avoid the cost of additional generation. For price-induced demand response programs to be truly effective (both in short-term emergency situations and in affecting the overall demand curve and market prices in the longer term), the price signals must be cost or market-based, rather than simply created to produce a predetermined response.

As a general principle, economic efficiency is promoted when customers make decisions based on current costs that reflect the actual economic impact of their decisions. It is also a matter of economic efficiency that rate components reflect their underlying cost structure. A customer's decision to increase the thermostat setting or otherwise reduce or defer energy consumption becomes the optimal economic decision when rates reflect the actual costs avoided.

In addition to rates being cost-based, dynamic pricing rates should provide a sufficient bill reduction when customers reduce or shift electricity usage to low-cost hours. Many customers could "lose" on dynamic rates, with higher bills despite the same or even reduced demand levels.[13] This preliminary bill impact analysis is troubling because most customers who significantly alter their behavior will only see minimal bill savings – and many customers will actually see *increased* bills. Such little reward – or negative bill impact – creates customer dissatisfaction and can create a backlash to dynamic pricing tariffs. Experience tells us that customers who have a negative experience will be less likely to choose to participate in future demand response programs.[14]

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13 For example, our preliminary analysis of critical peak pricing shows that 13% of residential customers will likely see a bill increase of 10% or greater, even though they reduce their usage during CPP events on critical peak days by 20%, while only 16% of customers will see a bill decrease of at least 10%. *See* Volume 2, Section III.C.

14 This potential outcome is similar to what happened to the Puget Sound Energy demand response program in which the customer bill reductions were relatively small despite significant customer behavior changes. Once customers realized they were saving so little or even paying more despite significant effort to reduce demand, they opted out of the program in large numbers,

Continued on the next page

We realize that important work still needs to be completed before a true "market" price will be readily accessible. It is unclear in what form capacity pricing will be reflected in the electricity market and how the Resource Adequacy Requirement will affect the volatility of energy prices in that market. Nevertheless, it is important that dynamic price signals mirror actual costs as closely as possible so that efficient demand response programs can be implemented. Thus, for AMI to become successful, it will be imperative that a functional market is operating from which we can develop appropriate cost-based rates.

C. Customers Should Be Informed and Allowed To Make Choices Among Tariffs

Our preliminary analysis discussed below establishes that an AMI deployment at any level will ultimately depend on significant and reliable demand response benefits to justify the cost. To the extent demand response benefits play this key role in the AMI cost benefit analysis, the Commission must be willing to put the appropriate policies in place to ensure that the required levels of demand response are realized. Achieving significant and persistent demand response would likely require that all customers take service on a tariff involving a time-differentiated rate, such as TOU, CPP-F or CPP-V rate structures.

We have long supported the underlying principle of providing customers with several rate options from which they can choose. SCE's success in its long history of reliability-based programs has focused on voluntary customer participation. We continue to believe that, ideally, customers should have the choice of rate options. However, to the extent that an AMI deployment depends on demand response

Continued from the previous page

leading the utility to cancel the program altogether. *See* Williamson, Craig, "Primen Perspective: Puget Sound Energy and Residential Time-of-Use Rates – What Happened?," Energy Use Series, Volume 1, Issue 10, December 2002.

benefits, the choice of alternatives may have to be narrowed to more dynamic rate structures. This is a difficult and contentious policy issue for regulators. In order to obtain the demand response that will make AMI cost effective, policy makers must be willing to take a more aggressive approach to make time-differentiated rates the default rate, which may be very unpopular with certain customer groups. For example, low income customers on the CARE or FERA rate may have little discretionary electrical usage and may experience increased bills from the imposition of default time-differentiated rates. Further, regulators cannot waiver from this path over the long term, even when prices fluctuate or increase due to market conditions.

Demand response benefits are realized when customers change behaviors to reduce peak usage. Just placing customers on time-differentiated rates will not necessarily create the desired demand response. There are two essential elements to achieve and sustain behavioral change. The first is customer education and awareness: If customers are not aware of the mechanics of the rate they have been placed on – and what they can do to save money – they obviously will not change behaviors. The second element is an economic incentive: Customers must be able to see results from their actions in the form of reduced bills in order to sustain their new behavior. Without substantial education and the economic incentive, even default time-differentiated rates will not produce the requisite level and persistence of demand response to justify an AMI investment.

SCE prefers that customers be offered a choice of rates, including time-differentiated, flat and tiered, as well as load control options. Customers should be empowered to understand their options and make the right choices. However, in order to obtain sufficient demand response to justify an AMI investment, customers may need to be defaulted to time-differentiated rates, with opt-out alternatives to other time-variant rates.

D. Summary of SCE's Management Philosophy and Business Vision

Our underlying management philosophy of pursuing investments that are the right choice for our customers in relation to other resources, as well as our overarching principles of cost effectiveness, cost-based price signals, and optionality have guided the development of our underlying assumptions and preliminary analysis of the AMI business case.

III.

SUMMARY OF AMI BUSINESS CASE PRELIMINARY ANALYSIS

A. Summary of Preliminary Results of Business Case Scenarios

The Ruling required that we perform at least sixteen unique business case analyses for various operational and demand response scenarios. Eight of these required scenarios involved full deployment of AMI to customers with demand below 200kW[15] and eight involved partial deployment. Some of these required scenarios assume no implementation of demand response programs using the advanced meters, so the only benefits are associated with operation savings, such as reduced meter reading expenses. Other scenarios investigate different types of demand response programs that might be implemented using AMI technology, including various forms of critical peak pricing (CPP) and time-of-use (TOU) rates. Several scenarios also assess the impact of demand response programs in combination with load control programs. Last, the Ruling required the utilities to analyze two scenarios involving outsourcing of AMI to a third-party supplier.

In addition to the required scenarios, the Ruling asked the utilities to undertake their own recommended analysis of additional scenarios using alternative assumptions. Given the volume of work this effort entailed and the comparatively short timeframe to perform the analysis of such a complex nature, we

[15] SCE has already installed communicating interval meters for most customers with demand above 200kW. As such, there are no associated costs of AMI for these customers and these customers are not included in the actual AMI deployment plans, even though, per the Ruling, the increased demand response benefits from these customers are included in the cost effectiveness analysis. We have already requested that the Commission address the ongoing “clean up” issue of interval meter deployment to large customers as part of our 2005-2008 Demand Response Proposal and thus, any costs associated with any new interval meters to customers with demand greater than 200 kW is considered to be part of “Business As Usual” outside of the incremental AMI analysis.

focused our preliminary study primarily on the Ruling's required cases, with much less time available to determine which alternative assumptions should be analyzed. Thus, our preliminary analysis identifies two initial assumptions that need to be reevaluated. These assumptions concern: (1) the estimate of customers opting out of dynamic pricing default rates, and (2) as a sensitivity, rate policies to determine what amount of customers will adopt dynamic pricing with or without the legislative constraints imposed by AB1-X. We applied these alternative assumptions to five of the required scenarios. Other than these two assumptions, we did not have adequate time to consider and analyze other preferred assumptions and intend to do so for the formal application. In addition, we developed two partial deployment strategies that may reduce technological and customer tariff adoption risk and may improve economic cost effectiveness.

In all, SCE has completed analysis on twenty-three separate business case scenarios. A summary of the costs, benefits, and Net Present Value (NPV) on both an after-tax cash flow and a revenue requirement basis for each of these scenarios is presented below. The summary of the preliminary analysis of our full deployment scenarios is set forth in Table 1-1 and the preliminary analysis of our partial deployment scenarios is set forth in Table 1-2.

Table 1-1 Summary of Preliminary Results – Full Deployment Scenarios (in millions 2004 Present Value dollars)						
No.	**Scenario Description**	**Details**	**Total Costs**	**Total Benefits**	**After-Tax NPV**	**Rev. Req. NPV**
1	Operational Only	Utility Implementation – Current Tariff	$(986.7)	$341.6	$(446.6)	$(1,120.0)
2**	Operational Only	Outsourced Implementation – Current Tariff	N/A	N/A	N/A	N/A
3	Operational + Demand Response	TOU Default with 20% opt-out	$(1,327.2)	$564.8	$(520.1)	$(1,244.3)
4	Operational + Demand Response	CPP-F/CPP-V Default with 20% opt-out	$(1,348.8)	$1,008.0	$(269.5)	$ (822.9)
5	Operational + Demand Response	Current Tariff with opt-in to CPP-Pure	$(1,265.9)	$511.7	$(515.2)	$(1,235.3)
6	Operational + Demand Response	Current Tariff with opt-in to CPP-F/CPP-V	$(1,265.9)	$508.6	$(517.0)	$(1,238.4)
7	Operational + Demand Response + Reliability	TOU Default with 20% opt-out plus load control	$(1,458.3)	$1,148.2	$(251.3)	$(793.5)
8	Operational + Demand Response + Reliability	CPP-F/CPP-V Default with 20% opt-out plus load control	$(1,529.7)	$929.5	$(423.7)	$(1,084.5)
9*	Operational + Demand Response	TOU Default with 50% opt-out	$(1,350.5)	$545.6	$(545.3)	$(1,286.8)
10*	Operational + Demand Response	CPP-F/CPP-V Default with 50% opt-out	$(1,358.5)	$657.0	$(483.9)	$(1,184.2)
11*	Operational + Demand Response + Reliability	CPP-F/CPP-V Default with 50% opt-out plus load control	$(1,519.0)	$741.8	$(528.9)	$(1,261.2)

* SCE's alternative analysis for optional scenarios beyond the Ruling's requirements.

** The outsourcing analysis cannot be represented in terms of the same cost, benefit, and NPV figures due to the nature of the cost information provided by vendors. The details of the Scenario 2 preliminary analysis are set forth in Volume 3, Section III.B.

As indicated above, none of the scenarios establish that a full deployment of AMI using any of the required assumptions is currently cost effective. The most favorable cases are Scenarios 4 and 7, which incorporate dynamic pricing demand response programs.[16] Yet, even the most favorable scenario, Scenario 7, has a negative revenue requirement present value of $(793) million.

For full deployment to have a positive NPV, either costs must decrease or benefits must increase substantially. It is more likely at the present time, however, that costs and benefits will go in the other direction. On the cost side, it is more likely that costs will be higher rather than lower because the technology envisioned by the Ruling is unproven and not commercially available at this time. In time, costs could decline as the technology matures. Alternatively, technologies that offer less functionality could have lower costs. On the benefit side, absent mandatory participation, it is hard to envision more demand response benefits than assumed in Scenario 4, for example, where eighty percent of customers adopt CPP rates for the duration of the study and are consistently as aware and as responsive as those who chose to be in the SPP experiment.[17] Scenario 7 has the highest demand response benefits but twenty percent of those benefits accrue from Advanced Load Control, which could be implemented without AMI.

As required by the Ruling, we also developed our preliminary analysis for numerous partial case scenarios. We have developed two separate, but potentially complementary partial deployment strategies, with various scenarios for each strategy. The first strategy would be to modify the default rate for RTEM customers with demand greater than 200kW from the current TOU default to a real-time pricing (RTP) rate in order to maximize demand response benefits with little to no additional investment. Although this approach is not strictly an "AMI deployment" because it relies on meters already installed, it does produce the only

[16] Although the Ruling required the analysis of Scenario 4, this scenario is unrealistic for SCE because it ignores the "crowding out" effect of SCE's load control programs by virtue of a widespread CPP deployment. Scenario 7 includes this offset. *See* Volume 3, Section III.D and III.F.

[17] For summer 2003, SPP customers were paid a stipend of $175 for their participation and hundreds of dollars per customer were spent on enrollment, education and awareness.

positive NPVs in SCE's preliminary analysis. The second strategy is a scaled-down version of the full deployment limited to Climate Zone 4.[18] The summary of the various partial scenarios for each strategy is presented below in Table 1-2.

[18] Climate Zone 4 was developed as part of the Statewide Pricing Pilot's climate zones and is the very hot, desert areas of SCE's service territory which contains approximately 440,000 SCE customers.

Table 1-2
Summary of Preliminary Results – Partial Deployment Scenarios
(in millions of 2004 Present Value dollars)

No.	Scenario Description	Details	Total Costs	Total Benefits	After-Tax NPV	Rev. Req. NPV
12*	Demand Response	RTP Default Tariff for all RTEM >200kW	$(17.9)	$237.9	$130.7	$219.7
13*	Demand Response + Reliability	RTP Default Tariff for all RTEM >200kW plus load control	$(373.3)	$469.7	$57.2	$ 91.9
14	Operational Only	Zone 4 - Utility Implementation – Current Tariff	$(161.9)	$30.8	$(85.0)	$ (441.7)
15**	Operational Only	Zone 4 - Outsourced Implementation – Current Tariff	N/A	N/A	N/A	N/A
16	Operational + Demand Response	Zone 4 - TOU Default with 20% opt-out	$(262.5)	$63.0	$(126.8)	$ (256.1)
17	Operational + Demand Response	Zone 4 - CPP-F/CPP-V Default with 20% opt-out	$(266.2)	$111.6	$(100.1)	$ (211.3)
18	Operational + Demand Response	Zone 4 - Current Tariff with opt-in to CPP-Pure	$(256.7)	$56.3	$(127.3)	$ (257.0)
19	Operational + Demand Response	Zone 4 - Current Tariff with opt-in to CPP-F/CPP-V	$(256.7)	$58.1	$(126.2)	$ (255.1)
20	Operational + Demand Response + Reliability	Zone 4 - Current Tariff with opt-in to CPP-Pure plus load control	$(567.8)	$474.9	$(63.4)	$ (153.1)
21	Operational + Demand Response + Reliability	Zone 4 - Current Tariff with opt-in to CPP-F/CPP-V plus load control	$(567.8)	$476.8	$(62.3)	$ (151.3)
22*	Operational + Demand Response	Zone 4 - TOU Default with 50% opt-out	$(260.1)	$69.3	$(121.6)	$ (247.4)
23*	Operational + Demand Response	Zone 4 - CPP-F/CPP-V Default with 50% opt-out	$(261.3)	$85.5	$(112.7)	$ (232.4)

* SCE's alternative analysis for optional scenarios beyond the Ruling's requirements.

** The outsourcing analysis cannot be represented in terms of the same cost, benefit, and NPV figures due to the nature of the cost information provided by vendors. The details of the Scenario 15 preliminary analysis are set forth in Volume 4 Section IV.B.

Although most of the partial deployment scenarios also prove not to be cost effective, there are some positive results. Importantly, as indicated above, the NPV is positive for Scenarios 12 and 13 concerning increased demand response benefits for RTEM customers. For the partial AMI deployment scenarios, we selected Zone 4 as the appropriate area of our service territory to perform the partial deployment analysis because the 2003 SPP results indicated that it was the climate zone that would result in higher demand response levels. In addition, a concentrated deployment in a specific geographic region has potentially higher deployment efficiency when compared to a less concentrated deployment throughout our entire service territory (*e.g.*, targeting higher-usage customers across the service territory). Our NPV analysis, however, indicates that the Zone 4 partial deployment scenarios are not cost effective today given the current cost and benefit estimates.

We prepared sensitivity studies on selected assumptions and scenarios that widen the range of results beyond the variety of assumptions and scenarios themselves. For demand response benefits, we considered the effects of the lost value of service to customers from the imposition of high peak prices. When customers forego usage they enjoy at today's prices, the procurement saving benefits obtained from lower usage at new prices are offset by the customers' loss of comfort and convenience. We calculated this benefit offset but did not include those results in the tables above. We also calculated the effect on results of assuming AB1-X precludes demand response benefits until the statutory provision expires in 2013. We have not yet computed added demand response benefits from assuming higher price elasticities than demonstrated in the SPP experiment. While increased responsiveness to prices would yield higher benefits, we believe that the key factor is customer participation in time-differentiated rates, especially CPP. We will continue to refine our study prior to our AMI application.

B. Summary of SCE's Preliminary Position on AMI

As the tables above establish, the preliminary analysis for each of the twenty-three business case scenarios indicates that none of the scenarios requiring AMI meter deployment has a positive NPV, meaning that none of the AMI deployment scenarios appears to be cost effective for our customers at this time. Only the two scenarios involving dynamic rate changes for the RTEM customers with demand greater than 200 kW showed to be cost effective at this time. The details of this preliminary analysis, including the specific costs, benefits, and uncertainties on a scenario-by-scenario basis are presented in Volumes 3 (full deployment) and 4 (partial deployment).

We consider this analysis preliminary as of this filing. We are continuing to refine this analysis as we begin to develop our AMI deployment proposal for the formal application required by the Ruling. As part of this effort, SCE also intends to evaluate whether other possible changes in the underlying assumptions, available rate options, or functional requirements may achieve significant cost savings or benefit increases that could improve the cost effectiveness of any of the AMI business case scenarios. To this point, we have not identified a viable AMI deployment strategy that will provide quantifiable benefits for our ratepayers.

Ultimately, this proceeding may conclude that the high level of risk and uncertainty of AMI warrants a more cautious approach, such as a smaller-scale or phased-in deployment or a delay in the deployment schedule until policy, legislative and technology uncertainties are resolved.[19] In order to open up the possibility of a cost-effective AMI deployment in the future, we hope that this proceeding will focus on *resolving* the uncertainties and challenges currently facing AMI. We realize that price-responsive demand response has an important role to play in the utilities'

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[19] *See* Volume 2, Section IV.

procurement portfolios and we believe that AMI can facilitate this important demand response resource. However, the timing and scale of an AMI investment will be important factors in determining whether AMI is the right investment for our customers at this time. SCE looks forward to presenting our formal AMI proposal after we have refined this preliminary analysis and conducted additional detailed analysis.

IV.

OVERARCHING POLICY CONSIDERATIONS

As noted above, our preliminary analysis using the Ruling's required assumptions for AMI demonstrates that it is not yet cost effective. We are continuing to refine this preliminary analysis and evaluate whether modifications to functional or rate requirements would improve the AMI business case. We are hopeful that in redefining the scope of an AMI deployment, we will discover potential cost savings that will improve its cost effectiveness for customers. In our view, for AMI to succeed, there are a number of underlying policy considerations that must be addressed, as discussed below.

A. Appropriate Rates Must Be Mandated for AMI to Be Successful

For an AMI business case to work at any level, the Commission must establish the appropriate policies to justify the investment. For SCE, AMI is not cost effective without significant demand response benefits. A commitment to optimize the level of demand response from an interval metering investment must be in place before the investment is made, otherwise, there will be significant risk that necessary benefits will not materialize.

One of the immediate steps the Commission can take to increase demand response is to maximize the benefits that can be obtained from current interval metering investments. We believe that if the Commission directs all RTEM customers with demands greater than 200 kW to move from a TOU default rate structure to a more dynamic pricing structure, such as a CPP or RTP rate, then benefits from this investment can be maximized. As discussed in Volume 4, this relatively simple step will increase demand reductions by approximately 180 MW, without any material additional investment or cost burden for our ratepayers.[20]

Although moving to a more dynamic default tariff may not be popular or customer-friendly (given that some customers will have negative bill impacts as a result), this is exactly the type of pricing policy the Commission would have to implement to optimize demand response from any AMI investment.

As noted above, full deployment of AMI simply is not cost effective on an operational-only basis and thus, a business case will depend on demand response benefits to overcome the gap between costs and benefits. If California goes down the path of building the infrastructure to support dynamic pricing tariffs, the Commission must be prepared to make the hard decisions so that the requisite levels of demand response will materialize and can be sustained. Without appropriate policies in place to ensure that reliable demand response savings will occur, AMI will likely not be the right investment choice for ratepayers at this time. However, with this commitment, the likelihood of sustained demand response benefits improves, along with the chances of success of AMI. We commit to continuing to work with the Commission in this proceeding to develop a workable and sustainable dynamic pricing policy.

B. The Legislative Constraints Imposed by AB1-X Must Be Removed for AMI to Be Successful

As alluded to in the Ruling, in the near term, legislative constraints on rate design modifications may have a considerable impact on the benefits derived from the full deployment of AMI.[21] The legislative constraints are the result of Section 80110 of the California Water Code enacted by AB1-X as a result of the 2000-2001

[20] *See* Volume 4, Section III (Scenarios 12 and 13).
[21] Ruling, p. 3.

energy crisis. Section 80110 prohibits the Commission from increasing any electricity charge for residential customers' usage of up to 130 percent of the existing baseline allowance. This prohibition is in place until the California Department of Water Resources (CDWR) power contracts expire, which is currently expected to occur in 2013.[22]

As the Ruling recognizes, the rate design restrictions required by Section 80110 will impede the ability to derive substantial demand response benefits under the full deployment scenario in the years prior to expiration of this constraint. This is because rates simply cannot be designed that will be responsive to critical peak or time-of-use price signals for a residential customer's entire usage given that 130 percent of customers' baseline usage would not be subject to dynamic pricing. In fact, a residential customer using less than 130 percent of its baseline allowance would never be charged time-of-use or critical peak prices due to the constraints of Section 80110. If Section 80110 remains in place, residential dynamic pricing schedules under a default or mandatory tariff enrollment would not be allowed until 2014, drastically reducing the potential demand response benefit.

As noted above, without substantial demand response benefits, the AMI business case is not cost effective and does not make sense for our ratepayers at this time. Successful AMI deployment will require the elimination of Section 80110, either through legislative repeal of the restriction against mandatory dynamic pricing tariffs for residential customers or through the expiration of the statute under its own terms. Because the potential for success of AMI hinges on the ability to require residential customers to take service under a time-differentiated rate, if the restrictions of Section 80110 cannot be repealed for reasons unrelated to AMI, then the Commission should consider delaying the ultimate decision on whether to

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[22] This sunset is based on the assumption that AB1-X is in effect until the last CDWR power contract expires, which is presently 2013.

move forward with AMI until the elimination of the statutory restrictions is guaranteed.

C. Challenges and Uncertainties Regarding AMI and Dynamic Pricing Demand Response Must Be Resolved for AMI to Be Successful

As discussed more thoroughly in Volume 2, there are a number of substantial challenges surrounding AMI, including technological/vendor risks, customer acceptance, and the unpredictability of reliable and persistent demand response. These primary challenges and uncertainties center on the central cost component (investment in the AMI system and cost to install and maintain) and the central benefit component (the avoided cost benefits from demand reductions) of the preliminary analysis. For the various business case scenarios, we have performed preliminary statistical analysis to attempt to quantify the value of the uncertainty. On a general level, our preliminary analysis indicates that the high degree of uncertainty with the main cost and benefit drivers makes AMI investment more speculative and risky at this time than other investments. An important focus of this proceeding will be to define the challenges of AMI and investigate measures that may resolve these uncertainties. We are confident that this proceeding will help resolve some of these uncertainties and provide answers to the ultimate question of when will be the right time to invest in AMI technology.

V.

CONCLUSION

Although still preliminary, our analysis illustrates that without modification, none of the AMI deployment scenarios are currently cost effective. We will continue to refine this preliminary analysis in the coming months as we prepare for the required formal application of our AMI proposal. The preliminary results do establish that for an AMI business case to become cost effective, there will need to be reliable and persistent demand response benefits to offset the substantial AMI investment costs.

These preliminary results also establish that significant additional demand response benefits can be obtained from customers with demand of 200kW and greater that have, for the most part, already received advanced metering.[23] If the Commission were to direct all RTEM customers onto a more dynamic default rate structure instead of their current TOU default, this relatively simple step could increase demand reductions by approximately 180 MW, without any material investment.

Although SCE continues to advocate customer choice, obtaining increased demand response benefits may require all customers to be on a dynamic rate structure. Thus, having already made the investment in advanced metering for the larger commercial and industrial customers, the Commission should consider putting the appropriate policy in place to reap the full demand response benefits

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[23] The vast majority of these customers already received communicating interval metering through the AB 1X-29 or through SCE. As set forth in SCE's Demand Response Program Proposals for 2005-2008, SCE has proposed that this "clean up" issue of providing meters for the remaining meters be resolved immediately. *See* SCE's Demand Response Program Proposals for 2005-2008 submitted October 15, 2004 in R.02-06-001, pp. 11-17.

from this investment, before it even decides whether additional investments in wider-scale deployment of AMI enhance value for our customers.

Proceeding No.:	R.02-06-001
Document No.:	SCE-2

SOUTHERN CALIFORNIA
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(U 338-E)

Advanced Metering Infrastructure Business Case Preliminary Analysis

Volume 2 – Approach and Business as Usual Case Analysis, General Assumptions and Risk Assessment

Before the
Public Utilities Commission of the State of California

Rosemead, California
October 22, 2004

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PRELIMINARY ANALYSIS OF ADVANCED METERING INFRASTRUCTURE BUSINESS CASE

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I.

INTRODUCTION

The purpose of Volume 2 is to describe our analytical approach to addressing the requirements of the Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure issued on July 21, 2004, (Ruling) and identify the key assumptions and risk areas that affect the results of this preliminary analysis. In Section II of this volume, we describe our overarching approach in conducting the preliminary business case analysis and how it addresses the requirements of the Ruling. We have complied with all of the requirements of the Ruling by gathering and compiling cost and benefit information for the sixteen required business scenarios and for seven additional scenarios. In addition, as required by the Ruling, the costs and benefits of each scenario were allocated, as appropriate, among eight Start-Up cost categories, forty Installation cost categories, thirty-one Operations and Maintenance (O&M) cost categories, and forty Benefit categories. Consistent with the Ruling, a key part of our analytical approach is the development of our Business As Usual base case, which is also described in Section II.

Section III includes a discussion of the key assumptions that have shaped this preliminary analysis, such as our selected Advanced Metering Infrastructure (AMI) technology solution, key deployment operating parameters, assumptions used in computing demand response benefits, rate design and bill impacts, financial assumptions and cost effectiveness, including customer value of service considerations. These fundamental assumptions are common throughout the preliminary business case analysis and are reflected in the scenario-by-scenario analyses presented in Volumes 3 and 4. In this section, we also provide a high level description of the revenue requirement necessary to support AMI based on the financial analysis of direct costs and benefits, as well as recovery of stranded costs as a result of replacing existing used and useful assets by the AMI meters and other related systems. The revenue requirement analysis is described in detail in Volumes 3 and 4.

Finally, in Section IV, we describe our assessment of key uncertainties and risks regarding the AMI business case deployment scenarios required by the Ruling. There are a number of substantial uncertainties concerning the primary cost and benefit drivers of the business case that must be resolved for AMI to be successful. In this section, we set forth strategies that could be implemented to mitigate some of the risk associated with these uncertainties.

II.

SCE'S ANALYTICAL APPROACH IN PREPARING THE AMI BUSINESS CASE PRELIMINARY ANALYSIS

The Ruling's business case framework was designed to address a high degree of uncertainty associated with a substantial investment in AMI deployment including customer response to time-differentiated rates (TDRs). As demonstrated by the sheer size of this preliminary filing, we have taken the requirements of the Ruling very seriously by preparing a thorough and comprehensive approach to our preliminary analysis, given the unprecedented nature of the AMI deployment contemplated in the Ruling. AMI as envisioned by the Ruling includes the capability of supporting widespread customer participation in critical peak pricing (CPP), which requires daily usage measurement and reporting as well as customer event notification. Such an effort has never been implemented to the mass market. In addition, a number of TDRs required by the Ruling for the business case scenarios were not explicitly tested by the Statewide Pricing Pilot (SPP), nor have they been widely implemented elsewhere.[1]

In this section, we describe our general analytical approach in preparing the preliminary analysis of the business case, as well as our approach to the required Business As Usual base case. Our general approach discussion also provides an overview of how we completed the specific scenario-by-scenario analyses presented in Volumes 3 and 4. The description of the Business As Usual scenario is fundamental to understanding our overarching approach because each of the

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[1] Two-part real time pricing (RTP), CPP Pure and CPP-Variable (CPP-V) without load control tariff offerings were not explicitly tested by the SPP. Although time-of-use (TOU) was tested in the SPP, the results were not statistically significant. Additionally, an "information-only" treatment group was tested in SPP but only limited data on bill impact results were produced by Working Group 3 (WG3).

scenarios presented in Volumes 3 and 4 are described to be incremental to this base case.

A. General Approach

We followed the analytical framework outlined in Attachment A of the Ruling by completing a Business As Usual base case, full and partial AMI deployment business cases, and scenarios involving various tariff and demand benefit assumptions. As specified by the Ruling, the business case analysis was broken down into separate scenarios which build upon earlier scenarios to isolate their differences. The base case is the foundation of all scenarios, upon which the operational-only scenarios are layered, followed by the various demand response scenarios, and finally the reliability scenarios. Our scenario parameters and assumptions were designed to allow for this building block analysis, to the extent possible. Moreover, the commonality of the assumptions between scenarios help highlight the differences between the various tariff options. The layout and key parameters of each of the scenarios studied in this preliminary analysis are provided in Table 1-1 below:

Table 2-1 Scenario Definitions		
No.	**Benefits**	**Key Parameters**
BAU		Existing advanced metering and communications, existing and planned load control, existing and planned outage management, major exceptions and expected investments. Base case to which other cases are compared to identify if any major investments and other costs/benefits are avoided if AMI is implemented.
1	OP	Full AMI – operational only – utility implemented
2	OP	Full AMI – operational only – outsourced
3	OP+DR	Full AMI – TOU tariff is default
4	OP+DR	Full AMI – CPP-Fixed (CPP-F) tariff is default for residential, CPP-V default for small Commercial and Industrial (C&I) (Exception: RTP for large customers covered in Scenario 12)
5	OP+DR	Full AMI – Current tariff with opt-in to CPP-Pure tariff (residential and small C&I)
6	OP+DR	Full AMI – Current tariff with Opt-in to CPP-F residential/CPP-V small C&I
7	OP+DR+ REL	Full AMI – CPP-F tariff is default for residential, CPP-V default for small C&I, includes load control for residential customers (Exception: RTP plus load control for large customers covered in Scenario13).
8	OP+DR+ REL	Full AMI – Current tariff with opt-in to CPP-Pure tariff (residential and small C&I) plus Advanced Load Control for residential
9*	OP+DR	Same as Scenario 3 with certain SCE recommended alternative assumptions
10*	OP+DR	Same as Scenario 4 with certain SCE recommended alternative assumptions
11*	OP+DR+ REL	Same as Scenario 7 with certain SCE recommended alternative assumptions
12*	ODR	Partial AMI: RTP mandatory for C&I customers 200kW or greater
13*	ODR+R	Partial AMI: Same as Scenario 12 except Schedule I-6 interruptible program maintained
14	OP	Partial AMI: Climate Zone (Zone 4) - operational only case
15	OP	Same as Scenario 14 except includes outsourcing
16	OP+DR	Partial AMI: Zone 4 – TOU tariff is default
17	OP+DR	Partial AMI: Zone 4 – CPP-F tariff is default for residential, CPP-V default for small C&I, no large C&I customers included
18	OP+DR	Partial AMI: Zone 4 – Current tariff with opt-in to CPP-Pure tariff (residential and small C&I)
19	OP+DR	Partial AMI: Zone 4 – Current tariff with Opt-in to CPP-F residential/CPP-V small C&I
20	OP+DR+ REL	Partial AMI: Zone 4 – Current tariff with opt-in to CPP Pure
21	OP+DR+ REL	Partial AMI: Zone 4 – Current tariff with opt-in to CPP-F residential/CPP-V small C&I
22*	OP+DR+ REL	Same as Scenario 16 with certain SCE recommended alternative assumptions
23*	OP+DR	Same as Scenario 17 with certain SCE recommended alternative assumptions
Benefits: OP=Operational, OP+DR=Operational + Demand Response, OP+DR+REL= Operational + Demand Response + Reliability		

* SCE's recommended analysis for optional scenarios beyond the Ruling's requirements.

Our preliminary analysis of the required business case scenarios followed the Ruling's prescribed requirements to the fullest extent possible. SCE performed a "bottoms up" analysis of the requirements and evaluated each of the costs and benefits categories defined by the Ruling. When costs and benefits were identified in each category, we estimated individual components in detail to the extent that time allowed. Costs were "rolled up" into the major categories of: (1) Start-Up and Design Costs, (2) Installation Costs, and (3) O&M Costs for each scenario, as required. Total costs for each business case scenario were compiled by year and entered into our financial model along with any operational and demand response benefits. An exception to this "bottoms up" analysis is the two outsourcing scenarios. We engaged an outside consultant to analyze these scenarios based on inputs from various companies with broad outsourcing experiences in this area. Due to the limited time allowed, these companies conducted a "top-down" analysis based on the requirements of the Ruling, and they have not used the detailed costs and benefits categories as in the other scenarios.

1. Approach Concerning SCE's Existing and Proposed Load Control Program

Implementing the Ruling's analysis framework required certain adjustments to account for our existing Air Conditioning Cycling Program (ACCP) and our proposed residential Advanced Load Control (ALC) program. ALC can be implemented independent of AMI in most scenarios and it is considered Business As Usual in our long-term procurement plan. However, the Ruling specifies that the utilities are to model Operational-Only cases, a series of Demand Response cases that exclude reliability, and finally a series of Demand Response plus Reliability cases. We therefore considered ALC and other load management programs to be "out of scope" for the Operational-Only and Demand Response cases, and thus did not include any costs or benefits from such programs in those scenarios. This is not to imply that we would not propose to move forward with ALC under those business case scenarios. Rather, in light of the Ruling's required "building block" approach to the various scenarios, the joint implementation of ALC and AMI is considered only in the Demand Response plus Reliability scenarios. Because the ALC technology can be compatible, or operate in tandem, with future AMI technologies, this largely mitigates concerns on potentially stranding ALC infrastructure investments if AMI is deployed in the future.

For the Demand Response plus Reliability cases, we have incorporated the proposed costs and benefits of our reliability programs, including impacts from the adoption of proposed CPP rates. Because the benefits of CPP demand response and load control may be duplicative, we assumed that customers may participate in either one program or the other. For Demand Response plus Reliability scenarios with large assumed implementation of CPP rates, our load control programs would necessarily be reduced in scope, as discussed in more detail in Volume 3 under Scenarios 7, 8, and 11. In Scenario 11, which is an alternative analysis, the reduction in our ALC program is included in our avoided-cost calculation.[2] For Scenarios 7 and 8, we use the Ruling's avoided cost assumptions.

We also assume that our partial business case scenarios involving residential deployment for Zone 4[3] are not materially affected by the ALC costs and benefits. We will fully deploy ALC under all of the Zone 4 partial scenarios, but the

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[2] The expansion of ALC to deploy to 500,000 residential customers was proposed in our Long-Term Procurement Plan (LTPP) submitted in R.04-04-003. Assuming this proposal is adopted, it has been incorporated into our own avoided cost calculations. To the extent that customers on a CPP rate displace ALC participants, the avoided cost value of the CPP load reduction is the cost of ALC rather than the cost of a combustion turbine.

[3] Zone 4 is one of the designated climate zones from the SPP representing very hot, desert areas.

costs and benefits of ALC (Net Present Value (NPV) of $25 million)[4] are not included in those AMI cases.

We did not examine a scenario with CPP-V rates with enabling technology for a number of reasons. First, while the SPP examined the demand response behavior of both residential and small C&I customers on CPP-V with Smart Thermostat technology, the results were not representative of the population because the participants had previously volunteered to be in the AB970 Smart Thermostat Pilot. Thus, these results cannot be generalized to the population at large.[5] Second, the economics of the CPP-V rate plus the cost/incentives of enabling technology have not been developed. Third, our ALC proposal will most likely be the most cost-effective solution for providing load control to the residential class. Finally, we already offer a Smart Thermostat program to small commercial customers.

2. Approach Concerning Outsourcing Scenarios

Our approach to the outsourcing Operational-Only scenarios is set forth in detail in Volumes 3 and 4.[6] Generally, this approach was to gather high level data through a modified Request for Information (RFI) process, with iterative steps for data gathering/clarification or refinement. This process was completed over approximately eight weeks. This process began with an evaluation of existing full service integrated solution providers that could potentially deliver the services that would be required in the outsourcing of AMI.

The integrated solution providers were asked to prepare a preliminary solution adequate to meet the requirements of the full deployment and partial

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[4] SCE's Demand Response Programs Proposal for 2005-2008, submitted in R.02-06-001 on October 15, 2004.

[5] Charles River Associates, Statewide Pricing Pilot Summer 2003 Impact Analysis, p. 103.

[6] *See* Volume 3, Section III-B and Volume 4, Section IV.B.

deployment scenarios. Their solutions were to be reasonably consistent with available technologies, and executable under the specified parameters. They were to include a price estimate, including a financial (pricing) model delineating when (or how) the charges would actually be incurred.

A baseline was created of the current meter organizations Field Service Meter Reading Organization (FSMRO), Meter Service Organization (MSO), and Transmission and Distribution Business Unit (TDBU) using 2004 budget information and recorded costs through July 2004. This baseline was used to assess the in-scope labor component and to determine our retained functions. For the sake of expediency, the financial data provided by the integrated solution providers was normalized through a series of communications with each of the service providers. This process also identified retained costs for SCE that would be considered as part of the end-to-end AMI solution and used in the comparison.

3. <u>Approach Concerning Quantifying Risks and Uncertainties</u>

The quantitative risks for each scenario were assessed by developing range estimates for most likely high and low sensitivities for each cost and operational benefit category with estimates greater than $5 million. We then used these values in statistical analyses using Monte Carlo simulation to identify the confidence levels of our estimates and potential contingency values. In each of the business case scenarios, our original estimates had very low confidence levels. A ninety percent confidence level, or the chance of not overrunning the cost, is reasonable for this type of project. The results of this analysis suggest that we should include contingency values for this project. While we identify the respective contingencies for several significant scenarios, we did not include the resulting contingency values in the cash flow analysis or revenue requirement due to insufficient time. However, we will consider including contingency values for the final application, as appropriate.

B. Business As Usual Base Case Analysis

1. Overarching Approach

The Business As Usual case, as described in the Ruling, is expected to serve as the "base case," or reference point from which to compare the relative costs and benefits of the various full and partial AMI deployment scenarios. This case serves three primary purposes: (1) to identify those significant metering and communications investments made that can be leveraged by AMI, and therefore should not be included in the deployment scenarios as new incremental cost; (2) to identify those investments that can be avoided if AMI is deployed; and (3) to identify those investments (*e.g.*, ALC) whose load reduction benefits will be replaced by implementing AMI. For purposes of this preliminary analysis, we define "Business As Usual" to mean no changes to our metering infrastructure or demand response programs beyond those currently in place or anticipated in the normal course of doing business under existing regulatory standards relating to these matters. Unlike the full and partial AMI deployment scenarios described in Volumes 3 and 4 respectively, the Business As Usual case is based on actual costs as recorded, and forecast in our 2006 General Rate Case (GRC) proceeding.[7] For the Ruling's required analysis period beyond the time period forecasted in the GRC (*i.e.,* 2009 through 2021), we trended costs based on our experience and judgment. By defining our Business As Usual base case in this manner, we are able to determine all incremental costs that would be incurred solely as a result of AMI deployment, as well as identify which base case costs would be eliminated by AMI.

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[7] *See* SCE's 2006 GRC Notice of Intent submitted on August 20, 2004.

Although we expect that technology improvements over the next sixteen years will likely change today's cost and benefit structure, to facilitate this preliminary analysis, our base case assumes that the current operating environment and cost and benefit structure will remain static over the sixteen-year study period.[8] We will make modifications or adjustments to the base case in order to avoid double counting of costs or benefits where appropriate. For example, full deployment of AMI meters would eliminate the cost of meter purchases that otherwise may occur under the base case. Similarly, the demand response scenarios with widespread enrollment in CPP rates would offset a portion of the anticipated costs and load reduction resulting from the ALC programs. These modifications are described in more detail in the scenario-by-scenario analysis set forth in Volumes 3 and 4.

Table 2-2 shows the recent history and our forecast of "business as usual" metering capital and O&M expenditures.

Table 2-2
Metering O&M and Capital Expenditures
Business As Usual Case ($ Million)

	Recorded					Forecast				
	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Metering O&M	$6.3	$5.4	$4.6	$5.1	$6.2	$7.2	$7.2	$7.4	$7.5	$7.7
Metering Capital	$12.8	$18.8	$12.6	$16.1	$17.6	$21.0	$20.1	$19.2	$19.0	$20.0

2. Existing Advanced Metering and Communications Infrastructure

In the normal course of doing business, we are constantly assessing the potential for improving operational efficiency and have already implemented

[8] Although unlikely, it is necessary to assume costs and benefits will remain static for our purpose here in order to establish the necessary baseline against which the other deployment scenarios can be compared.

advanced metering and communications technologies as previously mandated, as well as automated meter reading (AMR) in those areas where it appears to be operationally efficient and economically beneficial to ratepayers to do so.

a) Real Time Energy Metering (RTEM)

We currently have approximately 13,000 RTEM installations which measure fifteen-minute interval usage data for customers with monthly demands of 200 kW and greater. We also have approximately 700 RTEM units in place for our residential and small commercial customers who participated in the SPP. In addition, we have roughly 10,000 Dynamic Load Profile meters which are used to provide load data for system planning and California Independent System Operator (ISO) settlement purposes. Data is collected daily from these accounts via paging, telephone, and radio-frequency (RF) communications. Our automatic data collection system makes this data available to our largest customers via the Internet. This data is also used in the monthly billing for our largest accounts and thus, we no longer routinely read these meters manually. Full scale implementation of AMI would eliminate the need for the Dynamic Load Profile metering, given that these meters would be replaced with AMI meters. Some degree of load profile sampling and analysis may still be necessary, however, because this data-intensive process would be unmanageable with the entire population of interval data that would become available.

b) Automated Meter Reading

As discussed in Volume 1, we have been a pioneer in mass implementation of AMR, with over 500,000 meters that are currently read using AMR technology. Approximately 350,000 of these meters are installed in our highest cost-to-read routes and are being read from a "drive-by" van on a monthly basis. The remaining 150,000 meters are also high-cost-to-read meters (typically installed because of access problems or meter reader safety issues), scattered throughout our service territory. These meters are read monthly by the meter readers as they "walk-by" these locations on their routine monthly routes. All of our AMR systems utilize meters equipped with encoder/receiver/transmitters (ERTs) which could (theoretically) be paged hourly via a two-way radio network. However, because we are currently utilizing these systems only for monthly billing purposes, the walk-by and drive-by data retrieval method is more cost effective.

The AMR program is concentrated in those parts of our service territory where it is most cost effective. We continue to add approximately 20,000 new ERT meters annually as access or safety related problems arise, and we continue to monitor the cost/effectiveness of our existing meter reading routes. Thus, our Business As Usual case includes our estimate of future on-going costs of maintaining AMR and communications technology in today's operating environment. These costs are included as an incremental cost savings at the level appropriate based on the full and partial deployment scenarios.

Under the full-deployment scenarios, we have assumed that the entire AMR infrastructure is replaced by AMI. This replacement, on the Ruling's mandated deployment schedule, would leave us with an unfulfilled contractual obligation with a vendor for meter reading through 2011. Although these AMR costs would be stranded under AMI deployment, they are reflected in current rates. Thus, we did not make any adjustment to remove these costs from either the full or partial deployment scenarios so that these costs would continue to be recovered. There are no incremental operational savings, however, from re-automating existing AMR meters. To partially mitigate the cost of this fixed commitment, we have assumed the conversion of the AMR routes to AMI would take place late in the AMI implementation schedule, thus obtaining maximum value from the current contract.

c) Advanced Load Control

ALC systems can and do function effectively, independent of the proposed AMI infrastructure. This is the case with over 112,000 currently-active ALC participants whose air conditioning loads are controlled remotely via SCE's existing RF communication systems. In SCE's LTPP filed in R.04-04-003, we submitted our proposal to expand and enhance our residential load control program to increase the demand response this program delivers.

Although load control devices can be a complement to AMI and dynamic pricing programs, enrollment in the ALC program would likely be affected under a full AMI deployment scenario with a default CPP tariff. Though the base case costs associated with the ALC programs proposed in the LTPP would be substantially reduced, up to eighty percent of the load reduction anticipated from expected direct load control programs would also be replaced under the full deployment scenario by an eighty percent adoption of CPP. We assume that our proposed ALC program will go forward in all Demand Response and Reliability scenarios, except in the business case scenarios that contain CPP participation. In those cases, we adjust ALC tariff enrollment to reach an eventual twenty-five percent market penetration of residential service accounts with air conditioning that are not on a CPP tariff.

d) Outage Management System (OMS) and Transformer Load Management (TLM)

We have already invested in developing automated systems to assist us in detecting power outages (through the OMS) and managing load on our transformers (through the TLM system). As described in SCE's 2006 GRC, SCE continues to improve automation and data communications for its substation operations with Intelligent Electronic Devices (IEDs) that communicate through a

Local Area Network to our Supervisory Control and Data Acquisition (SCADA) System.[9] This modern protection and control equipment we are using provides remote, self monitoring control of substation function, and identifies potential problems to avoid or reliability events to which we must respond quickly. Among the many types of automation and sophisticated electronic equipment that we use in our substations and operations network are satellite communications for substation data collection and remote system control in areas where conventional methods of communication are not available or are too costly.

Because we already have adequately functioning OMS, TLM, and SCADA systems,[10] we already obtain associated benefits in our T&D activities.[11] As such, the potential added value related to outage management, transformer loading, and other T&D benefits that otherwise might accompany AMI for some utilities is virtually nonexistent for SCE. We have not included any incremental costs or benefits of AMI relative to these systems in our full and partial deployment scenarios. Therefore, the embedded capital costs, ongoing O&M costs, and all of the benefits associated with these systems are excluded from our Business As Usual case.

3. <u>**Major Expected Investments**</u>

We have already developed a significant infrastructure including Information Technology (IT) systems necessary to access, validate and store mass quantities of interval data. We have also developed the necessary interface with the

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[9] *See* SCE's 2006 GRC NOI, Ex. No. SCE-3, Vol. 3, Part IV.

[10] *Id*.

[11] However, these systems do not address an individual or small pocket of customer outages as would an AMI system. Usually when an individual or pocket outage occurs, the customer calls us. Because the marginal benefit of automatic notification via a meter to a very small number of customers affected for a short period of time is likely to be insignificant, no value was assigned for this preliminary analysis.

billing system to perform monthly billing for internal meters. The costs associated with this existing internal metering infrastructure are embedded in our rate base, as part of our historical recorded O&M expenses. These embedded costs are very difficult, if not impossible, to separate from existing non-internal metering embedded costs. For this reason, we have developed the costs and benefits associated with the partial and full AMI deployment scenarios on an incremental cost basis. This means that all cost and benefit estimates are incremental, over and above those currently included in the Business As Usual case.

a) IT Infrastructure Supporting Billing

Although much of the existing IT infrastructure that currently exists to support our RTEM and SPP program can be utilized in the AMI deployment scenarios, the existing IT systems have various design limitations which will hinder our ability to directly leverage these investments. The existing internal meter data handling and billing interfaces were built to process and store data acquired monthly from thousands of accounts, not hundreds of thousands or even millions of accounts as is anticipated in the partial and full AMI deployment cases. The incremental cost of developing and operating the new and expanded IT systems have been included in the cost estimates of each of the deployment scenarios.

b) Meter Reading Infrastructure

Meter reading cost and benefit estimates for each deployment scenario are incremental when compared to the base case. However, one adjustment was made to the Business As Usual capital budget presented in SCE's 2006 GRC. Full or partial deployment of AMI would eliminate the need for replacement of some of the meter readers' electronic hand-held computers. These devices will be out of warranty in 2007 and would otherwise be replaced due to wear and tear and technical obsolescence.[12] For the full deployment scenarios, the base case capital costs were reduced by $3.2 million in 2012, and another $3.2 million in 2017, to reflect this avoided cost of replacing these devices. For the partial deployment scenarios, the base case capital costs were reduced by $0.4 million in 2007, 2012 and 2017.

c) **Meter Replacement Costs**

Metering capital costs include not only the material cost of the meter itself, but also the labor cost of the initial installation and the final removal. For purposes of this analysis, the labor cost associated with installing approximately 72,000 new meters annually in response to normal customer growth is not expected to change significantly and has been left in the base case. The labor costs are not included in any of the full or partial scenarios as new costs. Material costs on the other hand will be significantly different for the various full and partial AMI deployment scenarios. The difference is the estimated incremental material cost of installing interval meters that meet the AMI functional requirements versus the current metering assets.

Each AMI deployment scenario incorporates the estimated cost of purchasing AMI meters for retrofit, replacement, and customer growth, as well as the avoided costs (benefits) of not purchasing electromechanical meters for replacements and customer growth.

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[12] *See* Exhibit No. SCE-4, Vol. 2, Chapter V.

III.

SCE'S KEY ASSUMPTIONS FOR THE AMI BUSINESS CASE PRELIMINARY ANALYSIS

Results of the preliminary business case scenario analysis are driven by several key assumptions. Some assumptions were provided in the Ruling while many additional assumptions had to be made to develop costs and benefits for our preliminary analysis. This section provides an overview of the overarching assumptions in the areas of AMI technology, demand response benefits, rate design, and financial analysis.

A. AMI Technology Assumptions

In Attachment A to the Ruling, we were required to design our business case around certain functional requirements of the meters and supporting network, which included specific a number of required technological and operational functionalities. This section describes our chosen metering and communications infrastructure solution and how this solution was selected. Additional details of the selected technology and how it would be applied in the various scenarios is included in the business case analyses in Volumes 3 and 4. Because of the relatively expedited procedural schedule to prepare this preliminary analysis, we have not yet analyzed whether any of the Ruling's requisite functionality requirements or tariff structures should be modified in a preferred analysis.

1. Technology Selection

The selection of an appropriate AMI technology is fundamental to the business case analysis required by the Commission. AMI system design should appropriately balance technology risk with our primary obligation as a utility whose principle objectives include operational and customer service excellence. Because the AMI system will be a key part of SCE's core business transactions system, only proven technologies should be considered for deployment in the AMI business case analysis.

a) Background on Technology Selection Process

In order to identify the appropriate AMI system for this business case analysis, we issued a vendor RFI to 23 potential respondents who have some level of experience with various metering and communications technologies. For confidentiality reasons and to avoid negatively impacting a possible future bid, we will not be disclosing the names of the vendors or any identifying details of their RFI responses. In the RFI, we required that the AMI solution must conform to the guidelines established by the WG3 Functional Requirements sub-team. A high-level summary of our interpretation of these guidelines is provided in Table 2-3 below:

Table 2-3 Summary of Required Functionality	
Elements	**Description**
Estimated Meter Quantity	Residential: 3,962,000 < 20 kW C&I: 586,621 20-199 kW C&I: 143,787
Data Interval	From fifteen minute to hourly increments
Collection Methods	Remote with manual read capability
Collection Frequency	Daily with on-demand read capability. Customer access to personal energy usage data with sufficient flexibility to ensure that changes in customer preference of access frequency do not result in additional AMI system hardware costs
Data available to Customer	Previous days data available to SCE next day by 8:00 a.m./Same day (near real-time) capabilities for subset of customer population
Customer Data Interface capabilities	KYZ output and/or other near real-time usage data presentation capability
Remote meter programming capability	Required

In response to our RFI, we received proposals from eighteen vendors. Once the proposals were received, we used criteria identified in the RFI to evaluate the responses, as set forth below in Table 2-4. These criteria are important because they are fundamental to balance system cost and service excellence. The criteria were weighted based on our experience in developing and deploying past technology solutions. A cross-functional team of SCE subject-matter experts was assembled to assess the vendor responses. The team addressed information gaps that, if unresolved, could significantly expose our ratepayers to unnecessary risk. Select vendors were contacted and provided with the opportunity to respond.

It is important to note that none of the eighteen vendors contacted provided a response claiming commercial availability of a fully-integrated ("under the cover") metering solution with two-way ALC interface with end-use devices such as AC thermostats (providing set-back functionality rather than operating as an on-off load switch). In fact, the majority of the respondents claimed that their AMI solution would be compatible with and/or would possess the ability to interact with future (*i.e.*, yet to be developed) modules that could facilitate ALC and/or in-home usage information devices. A handful of respondents did have commercially available load switches (on/off capable) to control one or more end-use devices, but these would not be categorized as possessing ALC functionality. A real ALC technology option with integrated ALC does not yet appear to exist.

From this RFI process and based on the evaluation criteria, we selected the most appropriate technology based on the Ruling's required functional specifications.

Table 2-4
AMI Request for Information Criteria

Evaluation Criteria	Description	Weighting
Reliability	The AMI technology solution's capability of ensuring data is not lost in the event of a component failure. Adequate redundancy needs to be balanced with cost considerations to maximize cost effective, reliable performance.	30%
Functional Requirements	The conformity of the AMI technology solution's functionality with the functional requirements of the RFI.	30%
Expected coverage	The AMI technology solution should reach at least 90% of SCE's customer base.	20%
Adherence to SCE (IT) Standards	The ability of the AMI technology solution to reduce project complexity, costs, and risks.	20%

b) Selection of Radio Frequency Technology Solution

Based on the evaluation process discussed above, we selected a balance of technological maturity and the technology solution's ability to leverage our existing communications infrastructure assets. Other technological solutions, such as power line carrier and other RF solutions, have some appeal but are not yet proven at the required scale, are still in the developmental stages, do not possess the data transmission capabilities, or are not available within the timeframe required by the Commission's business case parameters.[13]

Our selected RF technology had the greatest amount of flexibility and scalability given the various deployment strategies under consideration in this proceeding. In addition, this RF technology leverages our existing communications and metering systems. Our distribution system currently has a network of approximately 30,000 radio devices already installed and operational that are used for distribution management and interval metering purposes. From the vendors' responses, we understand that this solution has the ability to provide some level of protection against data loss, generally meets the functional requirements of the RFI and is capable of reaching ninety percent of our customers. It also appears to reduce project costs and complexity in comparison to other solutions.

Our selected technology will require that we replace all residential and small commercial meters with new solid state meters. Using a different RF technology that would allow retrofitting of a subset of existing meters was not found to be a more favorable alternative, given that retrofitting adds to the complexity of an already aggressive deployment schedule without providing any

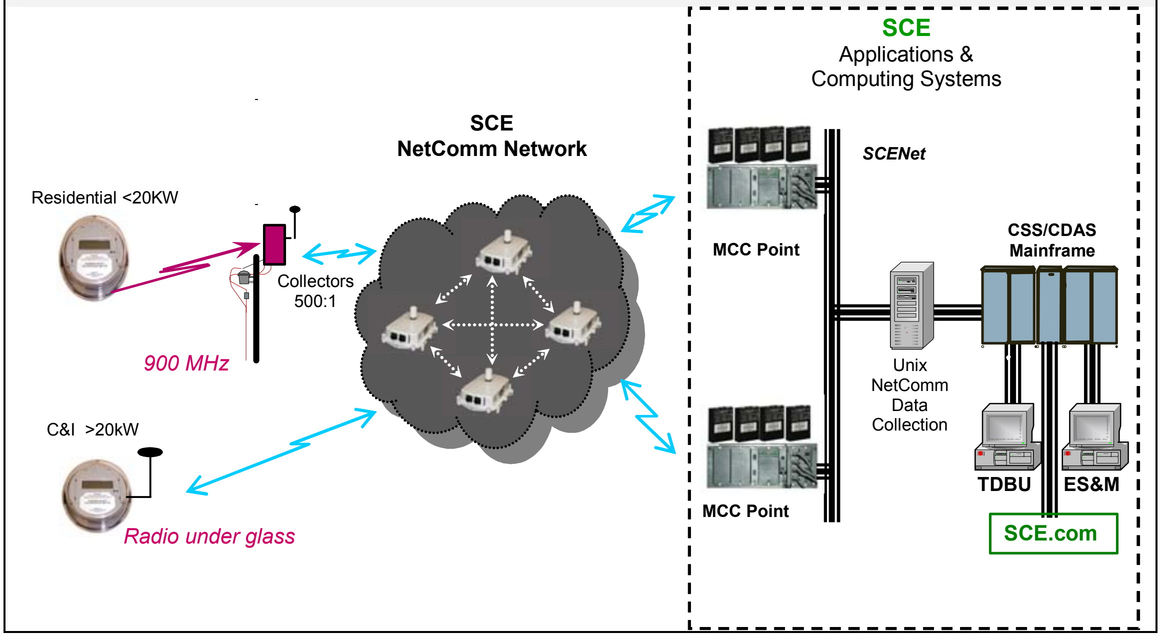
[13] For example, we recently attempted to test several metering solutions, but learned that some promised components are still under development and may be as many as 18-24 months away from delivery for testing purposes.

real cost advantage. Based on our experience in attempting to retrofit existing meters for the AMR program, we learned that retrofitting adds substantial complexity and operational cost, including retrofit compatibility issues, higher incidences of failures, and additional handling requirements. Based on the cost estimates for both solutions, we found there was no significant economic benefit to a retrofit solution compared to simply replacing all meters with new solid state technology and leveraging our existing RF network assets.

The selected AMI technology solution uses two RF technologies; one for residential meters and commercial meters less than 20 kW and one for greater than 20 kW meters. Meters using the first RF technology will be equipped with a radio that communicates with a "collector" to form a Local Area Network (LAN). The collectors will be mounted in the power space of a utility pole or streetlight and will typically communicate with meters within a 400 to 700 meter distance.[14] The greater than 20 kW meters will be equipped with radios under the meter cover and will communicate directly with the network. The two RF technologies are illustrated in Figure 2-1.

[14] Where a utility pole or streetlight is unavailable, such as in communities with extensive undergrounding of utility equipment, the collectors would have to be placed elsewhere, such as on an easement or leased site.

Figure 2-1
Illustration of Selected RF Technology



The Wide Area Network (WAN) is made up of the existing network, the addition of new radio devices, and the 20 kW and above meters equipped with radios. Each end-device radio generates a "packet" of data that travels the network by "hopping" from radio to radio in the direction of the destination-addressed radio. The route chosen for traveling the network is dynamic and employs an automatic rerouting system. This system automatically minimizes the amount of "hops" between the radios, which increases the transmission speed of the data packets. The packet is "addressed" to the communication controller take out point. Each point is connected to the SCE network.

The RF technology uses two distinct types of radio transmission spectrum technology to collect and send meter data. The residential and less than 20 kW commercial meters use a "direct sequence" spectrum technology. This technology typically provides a range of up to 0.5 miles from the meter to the collection device. The technology is one-way, from the meter to the collector. The

20 kW and above commercial meters use a “frequency hopping” spectrum technology in a license-free area of the radio spectrum. This technology provides a range of up to 5 miles. The technology will be deployed in two ways. In some cases, it will be under-the-cover of the meter, typically mounted at approximately five feet high. In other cases, it will be within the collection device normally mounted at a height of 20 to 30 feet. This technology is also peer-to-peer[15] and provides an unlimited number of “data hops.” This system is designed to be able to maintain high levels of reliability.

The selected RF technology meets the Ruling’s functional requirements among the alternatives considered. This same technological solution would be used for a partial case scenario, but scaled down in size to the targeted geographical area. The details of how this was scaled down are provided in the business case scenario analysis described in Volume 4.

c) AMI Technology Failure

Our technology solution uses solid state metering with electronic components. Throughout the course of the AMI deployment and thereafter, the solid state meters and associated communications infrastructure will experience some level of failure. This failure can be attributed to the actual hardware components failing and/or technology related (*i.e.,* RF) interference impeding meter data communications. These failures will likely result in a required field visit to the meter location to attempt to identify the source of the problem and may require additional investigation. Hardware failures may include one or more of the solid state meter components, the RF communications module, and/or the “collector” device, all of which comprise the LAN communications infrastructure. Hardware

[15] Peer-to-peer involves data transmission from house to house or premise to premise.

failures may be attributed to one of multiple causes, including manufacturer design flaws, defective material provided by other third party manufacturers or vendors (components used to build the meters and communications equipment), and/or defects in workmanship related to the assembly and construction of these components.

Based on our experience with testing new meter technology and with other solid state meter remote communication deployments, it is expected that a higher "meter" failure rate (AMI technology failure rate of the LAN components) will be experienced than the level of failures associated with our existing mechanical meters. We experienced a high level of equipment failures in our recent RTEM and SPP deployment due to communications and meter problems.

Over a three-year period, from 2001 through 2004, we purchased approximately 16,000 remotely communicating interval meters. The meters were used in both the RTEM and the SPP projects. The remote communication technologies deployed for these projects included wireless pagers, wireless radios (RF technology), and/or wired phone lines. Since initial deployment in 2001, approximately forty-eight percent of the 16,000 meter population has been returned for warranty repair. Meter recalls due to design or material defects accounted for sixty-six percent of these failures. The remaining thirty-four percent can be attributed to a combination of various material and workmanship related issues. These combined problems translate to an overall average annual failure rate of sixteen percent for our RTEM meters.

For the AMI business case analysis, we assumed a lower failure rate than that observed in our RTEM experience. Even though the rapid and wide-scale deployment envisioned under the full deployment scenarios, combined with potential competition for limited metering hardware may cause a higher incidence of product-related problems, we used an estimated failure rate that decreases over time. Our estimated failure rate is higher in the early deployment years, continuously declining until a steady state is reached in the fifth year of the five-year deployment. The average annual failure rate projected over the entire static meter population for the business case analysis is approximately two percent. The impacts from these failures will affect multiple organizations including but not limited to the Customer Communications Organization, Billing, FSMRO, and the Electrical Metering Services organizations.

d) Staging and Development of Applications

The Ruling's required five-year meter deployment schedule is quite aggressive and thus, would require that much of the communications infrastructure deployment and development of IT applications occur simultaneously. As a first priority, we would plan to focus on developing support applications for our supply chain management and meter installation work flow management functions that would necessarily need to be operational before any meter deployment could take place. In order to deploy AMI meters beginning in 2006, we would need to start developing these applications beginning early in 2005. All other remaining applications necessary to support AMI would start being developed in 2006 and would not be operational until mid 2007. The communications infrastructure would start being deployed in 2006 and would not be operational until mid 2007 as well. Deployment of the infrastructure will continue to fill in any coverage gaps identified during the remainder of the five year period to achieve the ninety percent coverage.

2. Data Collection

Data collection requirements vary by customer type and will depend on the different business case scenario in question. For the purposes of this preliminary analysis, we are recommending fifteen-minute data collection for all customers above 20 kW and one hour data collection for all customers below 20 kW.

This approach is consistent with Commission guidance in the Ruling. In an Operational-Only scenario for which there are no tariff requirements requiring more frequent polling, we would plan to collect aggregated, non-interval data much less frequently. In scenarios supporting demand response tariffs and the required provision of customer information, we plan to poll the meters daily for the energy consumed the previous day. As discussed throughout Volumes 3 and 4, the frequency of collecting data and the granularity of interval data that must be stored affects operational costs of various scenarios.

B. Demand Response Approach and Key Assumptions

In this section, we describe our key assumptions and approach for computing demand response benefits from TDRs enabled by AMI. Demand response benefits are driven by two factors: customer adoption of dynamic rates and customer response thereto. First, we describe our approach and highlight key uncertainties associated with small (<200 kW) customer acceptance and response to TDRs. Second, we provide our approach to estimating large-customer demand response to an RTP rate. Finally, we describe our approach and assumptions for the demand response benefit valuation by categories listed in the Ruling (DR-1 through DR-4).

1. Customer Adoption of TDRs Is Uncertain, but Nevertheless Critical to Demand Response Benefits But Such Adoption is Uncertain

a) Approach to Estimating Customer Adoption of TDRs

We used both assigned assumptions and calculated values for customer adoption rates across the various business scenarios. We assumed that the adoption rate, as a percentage of customers would hold for the full study period. For business case scenarios that used a default TDR with an opt-out option, we assumed that customers would elect the other available offerings on an equal basis.[16] For opt-in only tariffs, we used the Momentum Market Intelligence (MMI) customer adoption model to determine customer adoption rates. We also used the MMI model to estimate customer adoption of default rates in Scenarios 9, 10, 11, 22 and 23. However, the results of that model were so low that we assumed a fifty percent adoption of the default rate and spread the remaining customers on the other applicable tariffs on an equal basis, for analytical purposes.[17] Our assumptions by scenario are shown in Tables 2-5, 2-6 and 2-7 below.

[16] For example, if there are two optional rates, half of the 20% of participants that opt out of the default rate select one of the optional rates and the other half select the other optional rate.

[17] While this rate was not used for analysis purposes, the low rate from the MMI model provides a sensitivity result that is discussed in detail in Volume 3.

Table 2-5 Residential Customer Tariff Adoption Rates by Business Case Scenario									
Scenario	**Default Tariff**	**Other Tariffs**	**Full or Partial Deploy-ment**	**TOU**	**CPP-F**	**CPP-V**	**CPP-P**	**Current**	**ALC**
1	Current	None						100%	
2	Current	None						100%	
3	TOU	CPP-F or Current	Full	**80%**	10%	N/A	N/A	10%	
4	CPP-F/V	TOU or Current	Full	10%	**80%**		N/A	10%	
5	Current	CPP-P	Full				22	78	
6	Current	CPP-F	Full		11%*	8%*		81%*	
7	CPP-F/V	TOU or Current	Full	10%	**80%**			8%	2%
8	Current	CPP-P	Full				23%	69%	8%
9	TOU	CPP-F or Current	Full	50%	25%			25%	
10	CPP-F/V	TOU or Current	Full	25%	50%			25%	
11	CPP-F/V	TOU or Current	Full	25%	50%			20%	5%
12	Current	None						100%	
13	Current	None						100%	
14	Current	None						100%	
15	Current	None						100%	
16	TOU	CPP-F or Current	Partial	**80%**	10%			10%	

The percentages in **bold** indicate assumptions required by the Ruling. Percentages are of the total of C&I customers meters. * Indicates calculated assumption using MMI model.

Table 2-6
GS-1 C&I Customer Tariff Adoption Rates by Business Case Scenario

Scenario	Default Tariff	Other Tariffs	Full or Partial Deploy-ment	TOU	CPP-F	CPP-V	CPP-P	Current
3	TOU	CPP-F or Current	Full	**80%**	10%			10%
4	CPP-V	TOU or Current	Full	10%		**80%**		10%
5	Current	CPP-P	Full				34%	66%
6	Current	CPP-F/V	Full		22%	12%		66%
7	CPP-V	TOU or Current	Full	10%		80%		10%
8	Current	CPP-P	Full				34%	66%
9	TOU	CPP-F or Current	Full	50%	25%			25%
10	CPP-V	TOU or Current	Full	25%		50%		25%
11	CPP-V	TOU or Current	Full	25%		50%		25%
16	TOU	CPP-F or Current	Partial	**80%**	10%			10%
17	CPP-V	TOU or Current	Partial	**10%**		80%		10%
18	Current	CPP-P	Partial				31%	69%
19	Current	CPP-F/V	Partial		29%	9%		62%
20	Current	CPP-P	Partial				31%	69%
21	Current	CPP-V	Partial		29%	9%		62%
22	TOU	CPP-F or Current	Partial	50%	25%			25%
23	CPP-V	TOU or Current	Partial	25%		50%		25%

The percentages in **bold** indicate assumptions required by the Ruling. Percentages are of the total of C&I customers meters. * Indicates calculated assumption using MMI model.

Table 2-7
GS-2 C&I Customer Tariff Adoption Rates by Business Case Scenario

Scenario	Default Tariff	Other Tariffs	Full or Partial Deploy-ment	TOU	CPP-F	CPP-V	CPP-P	Current
3	TOU	CPP-F or Current	Full	**80%**	10%			10%
4	CPP-V	TOU or Current	Full	10%		**80%**		10%
5	Current	CPP-P	Full				34%	66%
6	Current	CPP-V	Full		22%	12%		66%
7	CPP-V	TOU or Current	Full	10%		80%		10%
8	Current	CPP-P	Full				34%	66%
9	TOU	CPP-F or Current	Full	50%	25%			25%
10	CPP-V	TOU or Current	Full	25%		50%		25%
11	CPP-V	TOU or Current	Full	25%		50%		25%
16	TOU	CPP-F or Current	Partial	**80%**	10%			10%
17	CPP-V	TOU or Current	Partial	10%		80%		10%
18	Current	CPP-P	Partial				31%	69%
19	Current	CPP-F/V	Partial		29%	9%		62%
20	Current	CPP-P	Partial				31%	69%
21	Current	CPP-V	Partial		29%	9%		62%
22	TOU	CPP-F or Current	Partial	50%	25%			25%
23	CPP-V	TOU or Current	Partial	25%		50%		25%

The percentages in **bold** indicate assumptions required by the Ruling. Percentages are of the total of C&I customers meters. * Indicates calculated assumption using MMI model.

Business case scenarios with high CPP customer adoption include significant marketing and customer education costs to maximize customer participation in CPP events and to maintain high levels of tariff enrollment. This cuts against market research that indicates customer adoption rates under opt-out default enrollment is inversely proportional to customer awareness. The higher the awareness of the default rate, the lower the likely market share. However, for CPP, low awareness is problematic because customers who are not aware of their rate will not respond consistently to CPP events, by definition. Because we are assuming demand response levels as experienced in the SPP, where customers were fully aware of their rates, we included marketing costs necessary to maximize customer awareness and maintain the participation levels over time. The issue of customer awareness and adoption is described further below.

b) Uncertainties Concerning Customer Adoption of TDRs

Despite a thorough SPP program and much analysis of customer preferences, significant uncertainty still remains regarding the level and reliability of demand response that will be achieved consistently under various demand response rate options. This is due to the substantial uncertainty regarding how many customers will remain continuously on a CPP rate structure. As shown in the business case scenario results, much higher demand response benefits are derived from CPP rates than from TOU rates because the estimated demand reduction per customer for CPP is generally higher than that for TOU rates. Thus, the assumption regarding the level and persistence of enrollment on a CPP rate is critically important in determining potential long-term MW and MWh reductions resulting from this rate structure.

There are several reasons for a high level of uncertainty regarding this critical assumption. First, there is only limited experience with customer acceptance of CPP-type rates in the residential class. CPP rates have not been implemented in a mass market, other than pilots, in the United States and thus, customers are unfamiliar with such rates.[18] Moreover, these rates may

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[18] Customers are generally familiar with peak/off peak time-of-use rates in the communications industry. However, CPP rates differ in that only certain sporadic days, when called by the utility, have very high rates. Customer notification is important and customer understanding of and reaction to that notification, good or bad, has not been examined outside of the SPP experiment where customers received incentives to participate in the program.

appear to be too risky to residential customers in comparison to the potential benefit. Only very few large SCE customers have signed up for the CPP tariff since it was offered in December 2003. The primary barriers to participation are: 1) the effect on products or productivity; 2) the level of on-peak prices or non-performance penalties; 3) the amount of potential bill savings; and 4) the inability to reduce peak loads.[19] Second, more than forty percent of customers surveyed preferred a tiered or flat rate over a variety of time-differentiated rates.[20] The utilities had difficulty recruiting customers for participation in the SPP experiment. Less than five percent of the customers initially contacted actually enrolled in the program, despite a $175 incentive payment. Moreover, the utilities contacted customers individually by telephone to get their agreement to participate in the SPP. Third, the results of market research conducted in the SPP concerning enrollment varied widely depending upon expected bill savings and customer awareness of the rate options available to them.

On a voluntary affirmative opt-in enrollment basis, the market research shows that less than ten percent of residential customers would adopt a CPP rate.[21] Only nine percent preferred CPP rates and twenty-nine percent of customers preferred TOU rates in a SCE market research study.[22] The fact that less than one percent of large C&I customers across all three respondent utilities have enrolled in CPP rates available today indicates a general lack of customer interest in such rates. The SPP market research found that the CPP-F pilot rate would yield an opt-in market share of ten percent of customers that had thirty

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[19] WG2 Evaluation Update – Market Survey Results, Quantum Consulting, Inc. and Summit Blue Consulting Inc., July 13, 2004, p. 16.

[20] Flexo Hiner & Partners, Inc., Final Report, February 11, 2003.

[21] Customer Preference Market Research Core Product Discrete Choice Simulator Residential Version 2.3 (with extrapolations) and Customer Preference Market Research Core Product Discrete Choice Simulator for Business Version 1.4 prepared by MMI.

[22] Flexo Hiner & Partners, Inc., Final Report, February 11, 2003.

percent awareness of their rate options, seventeen percent enrollment with fifty percent awareness, and thirty-four percent enrollment with one-hundred percent awareness.[23]

Of critical importance is whether default (opt-out) enrollment in CPP would actually result in high initial adoption rates. This must be balanced against the need for customers on a CPP rate to be fully aware of the need or opportunity to respond on CPP days. Enrollment by default, wherein customers do not fully understand their options, and only remain enrolled because they have taken no action, will not produce meaningful participation. In order to be effective, this type of enrollment must be coupled with educational outreach and gaining full customer awareness so that customers understand their rate structure and are in a position to respond to CPP events.

Customers who fully understand their electric rate options and the consequences of their actions are much more likely to actively and meaningfully participate. Customers who do not fully understand what it means when they are on CPP rates would not, by definition, adjust their usage during CPP events. The SPP experiment only tested the behavior of customers who were fully aware of the CPP rate. To use the SPP results for CPP, for example, full customer awareness must be assumed and the cost to achieve that awareness must be incorporated. The SPP demand reduction results for well-informed "treatment customers" on CPP rates would not be transferable to "unaware" customers. Therefore, we would need to take actions necessary so that customers are made aware of their new rate and that they know to reduce their usage during CPP events. Such actions include requesting that customers respond to mailings and attempting to contact by telephone those customers who do not respond. Their efforts would also include a

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[23] Momentum Market Intelligence, "Customer Preferences Market Research, A Market Assessment of Time-Differentiated Rates Among Residential Customers in California," December 2003, p. 98.

multi-year customer educational campaign that utilizes an integrated mix of media, including mass media, targeted ethnic media, and bill inserts, to affect long-term cultural and behavioral change. The campaign would be designed to: 1) raise awareness and educate customers about program specifications and benefits; 2) recruit customers; and 3) retain customer enrollment over time. A more detailed discussion of the necessary customer education and enrollment efforts is included in Volumes 3 and 4.

Such an outreach effort will likely reduce the enrollment of customers on CPP but will make their rate choice more meaningful with respect to the ultimate goal of demand response. We incorporated the costs of customer outreach to gain 100 percent awareness in the preliminary business case analysis in Volumes 3 and 4. Customer outreach is expensive. The cost of enrollment, education, awareness and retention in the SPP experiment was over $700 per customer.[24]

For certain business case assumptions, SCE used the MMI simulation model developed in the SPP to predict initial customer enrollment on tariffs based upon customer awareness and potential bill savings. Although the model results provide a point estimate, the margin for error in this approach is significant.[25] To determine default enrollment with heightened awareness (through outreach efforts), we used the MMI model to determine a range of potential customer adoption rates. The results of the model indicated very low customer adoption rates for CPP on an opt-out or default basis.

Sustained customer acceptance of non-mandatory CPP rates is also important. The assumption that eighty percent of customers will indefinitely

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24 The cost of marketing and enrolling SCE's 724 customers on the program was $510,000.

25 Momentum Market Intelligence, "Customer Preferences Market Research, A Market Assessment of Time-Differentiated Rates among Residential Customers in California," December 2003, p. 6.

remain on CPP rates required by the Ruling has never been demonstrated and is highly unlikely given the research completed to date. No utility has tested residential customer adoption of CPP rates on a default (opt-out) enrollment basis. Even the CPP treatment group in the SPP had an attrition rate of four to six percent, despite the offering of financial incentives to continue to participate in 2004.[26]

Moreover, sustained enrollment is not addressed in the MMI model and there is no experience elsewhere with residential CPP rates. Over time, customers who default onto a rate will become more aware of their options and will gravitate toward the one that is most beneficial. Market research shows that there is always inertia caused by perceived risk of a change in rates. One factor that could reduce inertia against change is that on average, customers tend to move residences every five to seven years and doing so would provide the customer an opportunity to reconsider his or her rate choices.

Thus, CPP adoption rates under a default scenario are difficult to predict due to a lack of real experience with such rates. Results of the SPP research indicate that customers respond more to very high on-peak prices under CPP rates than to the more moderate on-peak prices of TOU rates. Yet, the research also found that the vast majority of customers do not want CPP rates. If implemented on a default or mandatory basis, CPP could create a customer backlash. The repeal of the Puget Sound Energy's (PSE) short-lived TOU rate program is evidence of what can happen when customers become dissatisfied with TDRs. When PSE provided quarterly report cards to customers showing them how much they saved or didn't save on their TOU rate program, many customers realized that they saved very little or even paid more on the new rate and became

[26] Monthly Report on Statewide Pricing Pilot to California Public Utilities Commission and California Energy Commission, Exhibit B, January 15, 2004.

very upset. This initially resulted in a public relations problem and ultimately in PSE's decision to cancel the program.[27]

2. Customer Response to TDRs is Also Critical to Demand Response Benefits But is Uncertain

a) Approach to Estimating Customer Response to TDRs

Our approach to estimating the benefits of customer response to TDRs is based on the results of the SPP for Summer 2003. Where SPP results for a specific tariff are inconclusive, we relied on reasonable proxies. The SPP consultant, Charles River Associates (CRA) determined statistically significant findings for residential customers' response to CPP-F and CPP-V rates and small commercial customers' response to the CPP-V rate. Only the CPP-F results are directly applicable to the business cases. For other tariffs we used the following proxies as described below:

(1) TOU rates: SPP results were inconclusive for customers on TOU rates. However, CPP-F customers had a TOU rate on non-CPP days and the observed customer behavior on these days, as represented by a price elasticity, was used as a proxy for residential customers' demand response. For C&I customers, the TOU price elasticity was assumed to be twenty-five percent of that for residential customers. This estimate is supported by CRA and the literature.

(2) CPP-F for Commercial customers: SPP results were inconclusive. As a proxy, we used a price elasticity for C&I that is twenty-five percent of the residential price elasticity found in the SPP. This estimate is supported by CRA and by current literature.

(3) CPP-V for residential and commercial customers: CPP-V results in the SPP were for a select group of customers who also had enabling response technologies

[27] Williamson, Craig, "Primen Perspective: Puget Sound Energy and Residential Time-of-Use Rates – What Happened?," Energy Use Series, Volume 1, Issue 10, December 2002, p. 4.

and were therefore not representative. SCE used price elasticity for CPP-F as a proxy for CPP-V. CRA supports this proxy assumption.

(4) CPP-Pure for residential and commercial customers: This rate was not tested in the SPP. We used the price elasticity for CPP-F as a proxy. CRA supports this proxy assumption.

(5) Two-part RTP for large customers: Two-part RTP rate was investigated in WG 2 and no conclusions or guidance on how a rate could be designed were provided. We therefore used the literature to develop an approach to large customer response to RTP. This approach is described below.

(6) With respect to the number of customers eligible to enroll in TDRs, we assume that all customers equipped with AMI meters would be eligible, including customers eligible for CARE rates. We ignored the legislative requirements of AB1-X, as directed by Agency Staff in WG3.

(7) For Demand Response plus Reliability cases, we assume that customers on TOU rates would be eligible, but customers on CPP-F or CPP-Pure rates would not be eligible for ACCP participation. For commercial customers adopting CPP-V, we did not include an additional load control option. We assumed that the current Smart-Thermostat program covered that option.

There are two key components of estimating the demand response from TDRs; (1) the existing energy use by rate period for customers in the target population prior to the introduction of a new rate and (2) price elasticities, which are used to predict the change in energy use by rate period. Our approach to each of these components is described below.

(1) Existing Energy Use

We estimated the existing average energy use by climate zone and rate period for residential, GS-1 and GS-2 customers from our load research data. Our average energy use assumptions are shown in Table 2-8 below.

Table 2-8 Existing Average Energy Use by Class and SCE Climate Zone								
Rate Group	**SPP Climate**	**CPP Day**		**Non-CPP Week Day**		**Summer Week Day**		**Weekend/ Holiday**
	Zone	**Peak**	**Off Peak**	**Peak**	**Off Peak**	**Peak**	**Off Peak**	
Residential	**2**	0.67	0.53	0.63	0.50	0.64	0.50	0.55
	3	1.63	0.91	1.28	0.79	1.31	0.80	0.96
	4	1.73	1.02	1.44	0.89	1.47	0.90	1.08
GS-1	**All**	2.29	1.26	2.14	1.22	2.17	1.22	1.08
GS-2 < 200 kW	**All**	27.01	16.62	25.52	16.06	25.78	16.16	18.56

(2) Price Elasticities

The price elasticity econometric models were developed by CRA derived from statewide observations in the SPP. Two summary measures of price response used in this analysis are the elasticity of substitution and the daily price elasticity of demand. As described above, the elasticities used in the analysis are largely based on the SPP analysis. The SPP Elasticity data for all of California are found in Table 5 of the CRA August 9, 2004 report and are summarized for SCE climate zones below.

Table 2-9 Summary Measures for Price Responsiveness for CPP-F Rates CES Model Specifications						
Climate Zone	**Elasticity of Substitution (Weekday Peak to Off-Peak Electricity Use)**			**Price Elasticity for Daily Weekday Electricity Use**		
	CPP Days	Non-CPP Days	All Week-Days	CPP Days	Non-CPP Days	All Week-Days
2	-.061	-.053	-.054	-.029	-.026	-.027
3	-.099	-.091	-.092	-.014	-.010	-.011
4	-.121	-.109	-.111	-.032	-.024	-.025

Price elasticities for SCE were adjusted based on the weather conditions (*see* Table 2-10) and the central air conditioning (CAC) saturations representative of populations in our Climate Zones 2, 3, and 4 (see Table 2-11).

Table 2-10 Cooling Degree Hours by Zone and Period for Normal Year						
Climate Zone	**CPP Day**		**Non-CPP Day**		**Average Summer Day**	
	Peak	**Off Peak**	**Peak**	**Off Peak**	**Peak**	**Off Peak**
2	10.39	1.90	1.83	0.17	2.60	0.31
3	21.60	5.59	8.13	1.24	9.45	1.63
4	27.16	12.44	15.95	5.88	17.02	6.47

Table 2-11 SCE Central Air Conditioning Saturations	
Climate Zone	**CAC Saturation (Percent)**
2	21.2
3	57.81
4	60.89
All	41.91

With the guidance from the SPP consultants CRA, and a load reduction simulation tool, we derived load reductions for customers in our territory by making adjustments for air conditioning saturation and cooling degree hour. The impact estimates for residential CPP-F and TOU TDRs are shown in the table below. We used the same impact estimates on peak for CPP-V and CPP-Pure.

Table 2-12
Impact Estimates for SCE Specific Residential Tariffs
CES Model Specification

Climate Zone	Impact Measure	CPP-F Rate		TOU Rate	
		CPP Day Peak	Non-CPP Day Peak	CPP Day Peak	Non-CPP Day Peak
Zone 2	Change (kWh/hr)	-.12	-.01	-.02	-.02
	% Change	-17.92	-1.54	-3.23	-3.23
Zone 3	Change (kWh/hr)	-.40	-.06	-.07	-.07
	% Change	-24.82	-4.38	-5.28	-5.28
Zone 4	Change (kWh/hr)	-.45	-.09	-.10	-.10
	% Change	-26.00	-5.91	-6.60	-6.60

b) Customer Response to TDRs is Uncertain

Generally, customers tend to reduce their purchases of a commodity when faced with higher prices. The SPP experiment for 2003 provided certain estimates of customer behavior under CPP-F rates for residential customers statewide, under CPP-V for select residential customers in SDG&E's service territory, and under CPP-V for small commercial customers in SCE's service territory. CPP-V customers were equipped with smart thermostats that aided customer response to CPP events. The observed behavior in the SPP was within the range of customer price elasticity estimates found in the relevant literature.

The California SPP experiment – although limited in scope – likely provides more reliable estimates of price elasticity for electricity than an approach that derives likely customer behavior from past research of different rate structures from other parts of the world. Numerous studies of customer response to TDR have been performed since the energy crisis of the 1970s. The parameters of those studies varied widely, as did the results. The SPP experiment observed Californians in the current economy and employed parameters more closely resembling a potential AMI deployment. We used the SPP results as a basis for estimating demand response to the dynamic pricing scenarios. However, there are still issues and considerations regarding customer responsiveness to dynamic pricing that create substantial uncertainty in reliably estimating customer demand reductions in the business case scenarios. These issues and considerations include:

1) <u>Persistence</u>: The SPP results for 2003 are important, but additional study is needed to fully understand their persistence. Because AMI is a fifteen-year investment, sustained behavior, and therefore sustained demand response benefits, is critical. For example, the SPP experiment in 2003 and 2004 did not include any extended heat storms or highly unusual weather. The number of summer cooling degree days in 2003 and 2004 were 923 and 858, respectively. This is slightly cooler than the 1994-2003 period, for which the ten-year average was 1,050. How customers would respond to CPP events after several days of an extended heat storm or over a very hot summer is not yet known. Also, it is unknown whether customers will respond more or less to TDRs over time. Long-run price elasticities tend to be higher than short-run elasticities, suggesting that demand reductions would grow as customers make home improvements or make permanent behavior adjustments. However, long-run elasticities remain uncertain because of the unique aspects of the CPP rate model.

2) Applicability of SPP Results: SPP results reflect customers who voluntarily selected the rates (opted in) and were provided a substantial participation incentive, which likely served to mitigate some downside risk. It is doubtful that all customers placed on a CPP rate by default would behave in the same way as these SPP participants who voluntarily elected a change in rates for a limited-duration experiment and an incentive payment. Customer behavior for those who opt in without an incentive is also unknown.

3) Price Elasticity: The estimates of price elasticity in contemporary literature vary widely. Although the SPP observed behavior is the most relevant for estimation in this preliminary analysis, actual customer behavior could vary significantly according to the prior research.[28]

4) TOU Customer Demand Response: The SPP experiment found no statistically-reliable demand response in the TOU rate treatment group. For the purposes of this preliminary analysis, we used the demand response from the TOU portion of the CPP rate. This is not necessarily representative of customer behavior on TOU rates alone because CPP customers were notified individually of CPP events.

5) CPP Demand Response for commercial customers: The SPP experiment found no statistically-reliable demand response from TOU or CPP rates for commercial customers. Because prior studies generally indicate that commercial customers have about one-fourth of the price responsiveness as residential

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[28] The SPP only tested short-run price elasticities. Literature on the subject suggests that long-run price elasticities can be much higher than short-run because customers will make investments in response to prices. This is likely to be true, although long-run price elasticities may have little effect on the business case. Long-run effects include customer investments such as insulation or new appliances over a long period of time, especially towards the end of the study period where the impact would be highly discounted in present value. *See, e.g.,* King, Chris, "Summary of Dynamic Pricing, Demand Response, and Advanced Metering Studies," October 1, 2002. Also, Essential Services Commission, Melbourne, Victoria Installing Interval Meters for Electricity Customers – Costs and Benefits, Position Paper, November 2002, pp. 61-67. .

customers, we used that ratio and applied it to the demand responsiveness estimates of residential customers that participated in SPP.[29] This is a very preliminary estimate, which makes the demand response benefits analysis for commercial customers less certain or reliable.

6) CPP Pure Rates: The SPP did not test CPP-Pure rates, although one of the Ruling's required business case scenarios involves a CPP-Pure tariff option. We simply do not know how customers will respond to such rates. The rates are similar to CPP-F, but they do not have a seasonal TOU component and the non-CPP event (off-peak) rate component is higher than the off peak component of CPP-F rates. Some customers on CPP-F may have set their programmable thermostats to respond during peak hours on both CPP and non-CPP days (for the TOU portion). While we used CPP-F demand response estimates from the SPP for CPP-Pure, that the assumption may represent the high end of the range of expected customer response.

7) CPP-V Rates: The SPP experiment determined customer response to CPP-V rates only for a select group of customers in the San Diego area with larger homes and air conditioning who were already part of a Smart Thermostat pilot program. This customer sample is not representative of the population as a whole. Thus, we used the CPP-F demand response estimates from SPP for CPP-V in our analysis. It is not known whether customers on CPP-V would respond more or less than CPP-F customers.

8) CPP-F Rates: Our proposed CPP-F revenue-neutral rates have a price ratio of fourteen to one between the critical-peak price and the off-peak-price. The SPP experiment used rates with a price ratio of about five to one. A higher price ratio is thought to result in greater demand response, but this cannot

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[29] *Id.* Essential Services Commission, p. 66. Ahmad Faruqui of CRA, confirms that 25% of residential price elasticity is a reasonable estimate for small commercial customers.

be confirmed by SPP results. We estimated a higher demand response under the proposed rate using the CRA demand reduction simulation tool[30] compared to the SPP rates. We also did preliminary analysis of rates similar to the SPP rates for SCE and found the demand response to be lower than the rates we propose herein. We recognize that we are likely pushing the CRA simulation tool beyond its reasonable limits thereby increasing the range of probable results. The customer acceptability of the proposed rates and the actual demand response has not been tested.

In sum, where available, we applied the demand response observations from SPP. For reasons discussed above, these estimates are preliminary and yield uncertain demand response results. These substantial issues and uncertainties must be resolved before a final decision to deploy AMI can be reached.

3. Two-part RTP (>200 kW Customers)

Our basic approach to estimating large customers' response to an RTP rate was to start with the results of the study that Christensen Associates performed for the California Energy Commission (CEC)[31] to estimate the statewide savings due to the potential implementation of RTP across the three major California investor-owned utilities. We applied those results, by Standard Industrial Classification (SIC) code, to the population of SCE customers with peak demands over 200 kW.

We also considered two scenarios, one in which all customers over 200 kW were moved to an RTP tariff, and one in which those customers currently served

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[30] Charles River Associates, Inc. Pricing Impacts Simulator Model (PRISM). PRISM results show that the higher the price differential, the higher the demand response.

[31] Potential Impact of Real-Time Pricing in California, by Steve Braithwait and David Armstrong (Christensen Associates), January 14, 2004.

on an interruptible rate (Schedule I-6) remained on the interruptible rate, and those served on any of the firm service rate schedules were moved to an RTP tariff.

Using the results of the Christensen report, we were able to make a preliminary estimate of the MW savings at system peak from firm and interruptible customer groups. The estimates are shown in the table below. The process we employed to arrive at these preliminary estimates is described more completely in Appendix A of this volume.

Table 2-13
Estimated Demand Reductions from RTP Tariff for Customers with Demand >200 kW

Group	Total Group Contribution to System Peak	Estimated Savings at System Peak	Percent Savings
Firm	4,318.5 MW	185.4 MW	4.3%
Interruptible	795.2 MW	175.9 MW	22.1%
Total	5,113.7 MW	361.3 MW	7.1%

These estimates reflect the mix of SCE customers over 200 kW and the price response from the Christensen analysis done using real-world experience of the Georgia Power RTP program. They do not reflect the actual load shapes of these particular SCE customers, or the prices that SCE customers paid during September 2003, when the system peak load data were collected. However, by using the same responses and load shapes that were used by Christensen, the results of our analysis are consistent with the statewide estimates from the Christensen analysis.

4. <u>Demand Response Benefit Categories Approach and Assumptions</u>

The Ruling identified four potential Demand Response benefit categories to be evaluated in the business cases. Those categories are:

a) DR-1: Procurement cost reduction
b) DR-2: System reliability benefits (capacity buffer)
c) DR-3: Dynamic fuel switching/dynamic integration of conventional and distributed supplies
d) DR-4: Avoided/deferred transmission and distribution (T&D) additions/upgrade costs

For SCE, only DR-1 and DR-2 provide quantifiable benefits that should be included in the business case analyses. Our approach and assumptions for each Demand Response benefit category is described in the subsections that follow.

a) **DR-1: Procurement Cost Reduction**

TDRs enabled by AMI that result in peak load and energy reductions would yield a reduction in the utility's procurement costs. Such costs that are truly avoided should be counted as benefits in the business case. Avoided costs can be estimated by a "proxy method" where a simple assumption is made that the procurement costs avoided are calculated assuming a single avoided resource cost for capacity and for energy, at all times, as an approximation of the actual costs avoided which in practice vary hour by hour and day by day.

The Commission directed parties to use a "proxy method" namely, $85/kW-yr for capacity savings and $70/MWh ($63/MWh for peak energy plus $7/MWh for congestion) for the energy savings provided by AMI. Off-peak energy was assigned a value of $45/MWh. The values for peak energy are similar to the levelized capital cost of a combustion turbine (CT) operating at a gas price of close to $6/MMBTU. Equating these resources in value is incorrect given the different benefits provided by these resources. In addition, there are other demand-side programs at SCE's disposal. SCE analyzed alternative demand and supply options and compared the cost-effectiveness of SCE's option versus an AMI program.

(1) Portfolio Valuation Approach to Valuing Demand Response

SCE filed its LTPP in R.04-04-003. A least-cost, best-fit portfolio of supply and demand-side resources was developed based on a forecast of expected demand. Existing supply and demand resources were included in the portfolio and the residual end-use demand was met by new demand and supply-side resources. The resource portfolio was designed to meet resource adequacy and renewable resources targets and adhere to the Commission's preferred resource loading order. Details of SCE's portfolio method can be found in testimony filed in R.04-04-003.[32]

We determined the amount of supply-side resources that are necessary to achieve our required reserve margin on the basis of peak demand. The resource adequacy requirement is equal to expected peak demand plus a margin of fifteen percent. Expected load reductions from TDRs and other demand-side programs are included in our portfolio design process as peak demand modifiers. A demand-side program not only reduces the actual demand we must serve but also reduces the reserve margin target (the latter is considered as a capacity buffer benefit (DR-2)).

For selected scenarios, the procurement cost impact of AMI was determined by comparing the portfolio of each scenario (9, 10, 11, 22 and 23) to SCE's least cost-best fit portfolio using a medium load forecast. The residual demand requirements for the portfolios are met with least cost-best fit resources.

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[32] *See* Volume 1, Section 5 of SCE's 2004 Long-Term Procurement Plan, filed on July 9, 2004.

SCE's portfolio relies on ALC and peaking products similar to a combustion turbine to meet our resource adequacy targets.

(2) Observations on the Ruling's Assumptions for Calculating DR-1 Benefits

The Commission has overvalued the benefits of demand reductions from TDRs by directing the use of $85/kW-yr for capacity and $70/MWh for peak energy. The capacity value is overstated given the supply and demand options available to SCE. The capacity value of $85/kW-yr should be reduced to reflect the cost of a combination of the levelized capital cost of SCE's peaking resource options and the cost of SCE's proposed ALC program. Our portfolio of supply-side peaking resources and our ALC program proved more cost-effective over the range of scenarios.

b) DR-2: System Reliability Benefits (Capacity Buffer)

We agree that for load reductions from proven load response to TDRs, reserve requirements are avoided. For the Ruling's required scenarios, we included the entire load reduction from the TDRs. In those cases, we also apply a system reliability benefit of fifteen percent reserves. We calculate a value for this benefit at the avoided capacity cost defined by the Ruling ($85/kW-year) for inclusion in the required business case scenarios and we use our portfolio method to value this avoided capacity in Scenarios 9, 10, 11, 22 and 23.

c) DR-3: Dynamic Fuel Switching/Dynamic Integration of Conventional and Distributed Supplies

TDRs enabled by AMI do not provide reliable and rapid response that would enable or improve the dispatch of resources on our system above and beyond the current methods and system capabilities. For example, we have system monitoring and metering at a substation level. It unclear how increased granularity from interval metering at the end use will provide us additional information to facilitate fuel switching or the integration of distributed generation. The avoided cost savings attributable to AMI for dynamic integration benefits are included in the capacity payment since this payment reflects the cost of a combustion turbine that provides full dispatch capability. Including a separate adder would amount to double counting the savings attributable to dynamic integration benefits.

AMI metering at the residential level is not likely to be aggregated or evaluated in a way timely for fuel switching. AMI does not provide measurable benefits since the amount of energy saved by the AMI program is minimal. Significant fuel diversity savings are caused by programs that save a significant amount of energy thereby affecting the fuel mix required to produce energy.

Moreover, it is unknown how such information, assuming more geographic granularity is better, would translate to quantifiable benefits. Of course, if there were potential benefits to consider, the costs associated with the required systems and applications would also need to be included. Accordingly, without better information concerning this category at this point, we have omitted it from our scenario analyses.

d) DR-4: Avoided/Deferred Transmission and Distribution (T&D) Additions/Upgrade Costs

For a number of reasons, we do not believe that TDRs enabled by AMI provide reliable and durable load reductions which avoid transmission and distribution upgrades. Transmission network upgrades or expansions are required to avoid congestion. However, congestion on specific transmission lines can be caused by generator or system outages and more typically occurs during shoulder months rather than at peak times, when most supply-side resources are available. Secondly, TDRs are subject to change. If a transmission upgrade was deferred due to expected demand reduction from a TDR and the rate is modified, system reliability could be immediately threatened. SCE does not believe that demand reductions from TDRs can be counted on in transmission planning until there are many years of experience.

With respect to distribution additions/upgrades, we believe that there again are no quantifiable benefits from TDRs for the same reasons discussed above. Moreover, TDRs, especially if CPP programs were implemented widely, could actually cause more loading on the distribution network when the rate changes from peak to off peak. For example, assume a residential distribution circuit sized to handle 20 MW of otherwise diversified residential customer load. By signaling a high priced CPP event, customers are encouraged to not use energy during high system peak periods. When the CPP event is over and those customers who responded to the program begin to use energy again, there is a risk that the increased coincidence associate with this load will overload the distribution circuit. The phenomenon of distribution system loading can be understood by examining the actual load profile of SPP participants on a CPP day where a higher peak than would otherwise occur was observed in the evening hours.

5. **<u>Economic Perspective For Analysis</u>**

We are using the all-ratepayer or societal perspective for this preliminary analysis. The costs are the investment and operational costs of implementing AMI. The benefits are the operational savings and demand response benefits (*i.e.*, resource cost savings), less the value of service loss to customers. The implications of value of service loss on the analysis have not been extensively discussed in workshops leading up to this filing. However, value of service impacts are an essential element of a proper analysis.

If customers are forced to curtail usage to avoid higher bills, they essentially face a decline in service for the same money or incur a loss in the value of service previously provided. While usage curtailment at peak would reduce the utility's production costs, customers may be worse off to the extent that they experience less comfort or have to change usage habits. This value of service loss should be taken into account as a societal cost that offsets societal benefits of reduced production costs. This is discussed below in detail.

The traditional method the Commission has used to evaluate utility demand-side management programs is the Demand Side Management Standard Practice Manual (SPM).[33] The SPM recommends presenting results from a variety of perspectives, including those of the program participants, other ratepayers (non-participants), and all ratepayers or society. The all-ratepayer or societal perspective is a measure of overall economic efficiency, while the participant and other ratepayer perspectives address the distributional (cost shifting) impacts of a program. The participant perspective can also be helpful in the design of appropriate incentives.

Programs involving dynamic pricing demand response options, such as those enabled by AMI technologies, cannot be directly evaluated using the SPM equations, however, because these equations omit the impact of price-induced changes on customer usage behavior.[34] Changes in customer usage affect the value

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[33] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, Interagency Green Accounting Working Group, October 12, 2001.

[34] Although the equations contained in the SPM do not reflect value of service impacts, there is some indication that the authors intended such impacts to be considered: "However, attempts should be made to quantify indirect costs customers may incur that enable them to take advantage of TOU rates and similar programs. If no customer hardware costs are expected or estimates of indirect costs and value of service are unavailable, it may not be possible to calculate the benefit-cost ratio and discounted payback period." *Id.*, p. 17

or benefit that a customer obtains from using electricity, and this needs to be taken into consideration in program evaluation. For example, an attic insulation program allows a customer to use less electricity while maintaining the same house temperature, so there is no effect on customer value. In contrast, a dynamic pricing program which raises prices on hot summer afternoons achieves lower usage by inducing the customer to increase the thermostat setting and thus forego some level of comfort. This loss of comfort (*i.e.*, maintaining the home at a higher temperature than the customer otherwise would) has some lost value associated with it. Introducing an additional term in the SPM equations to reflect this value of service loss is thus necessary to properly value pricing demand response programs.

As set forth in Appendix B to this volume, we have developed a mechanism for determining a value for the loss of service and we have applied it to many of the business case scenarios. The approach found that the benefit of demand response declines significantly. Thus, it is imperative that in the Commission's review of the cost effectiveness of AMI and of demand response programs, the full costs, including the loss of value from service, are included. The SPM formulas, with the inclusion of a value of service loss element, yield an appropriate measure of the economic efficiency gain from introduction of price-based demand response programs. In contrast, using just resource cost savings as a criterion does not produce appropriate results.[35]

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[35] *See* Acton and Bridger, *op. cit.*, p. 23 ("Despite the widespread agreement among economists that the welfare measures constitute a correct measure of the impacts on well being, the criteria are frequently ignored in evaluating rate changes" and ". . . both the fuel savings criteria and the fuel plus capital savings criterion are wrong in principal, and in general, will lead to substantially incorrect measures of benefits").

C. Rate Design and Bill Impact Assumptions

Consistent with the Ruling, all rates (various CPP and TOU) designed for the AMI business case scenarios for residential, small commercial, and medium commercial customers were designed to be revenue neutral to their respective otherwise applicable tariff (OAT). For each rate class, rates were designed with TOU periods being consistent with existing or experimental CPP rate structures). The design structures are summarized in Table 2-14 below and discussed in detail in Appendix C.

Table 2-14
Experimental/Existing CPP Rate Structures

	RES	GS-1	GS-2
Existing CPP Tariff =>	TOU-D-CPPF	TOU-GS-1-CPPV	GS-2-TOU-CPP
On-Peak/CPP Event =>	S/W: 2pm-7pm	S/W: Noon-6pm	S: Noon-6pm
Season-Months =>	S/W - 6/6	S/W - 4/8	S/W - 4/8
Rate Structure =>	S/W: On/Off	S/W: On/Off	S: On/Mid/Off W: Mid/Off
	Proposed AMI CPP Rate Structures		
	RES	GS-1	GS-2
On-Peak/CPP Event =>	S/W: 2pm-7pm	S/W: Noon-6pm	S/W: Noon-6pm
Season-Months =>	S/W - 6/6	S/W - 4/8	S/W - 4/8
Rate Structure =>	S/W: On/Off	S/W: On/Off	S: On/Mid/Off W: Mid/Off

The process we used to analyze our proposed rate design and bill impact analysis is described in Appendix C of this Volume.

Under CPP-F, customers are subjected to a fixed number of hours per daily CPP event (Residential: five hours, Commercial: six hours). Under CPP-V, customers are subjected to three hours per CPP event day. CPP-Pure (CPP-P) is designed as an overlay of existing rates, with the added revenue during CPP hours being offset by a percent reduction in the charges of the OAT. Using 2003 annual rate group load data, CPP "events" were defined with 100 percent certainty to occur on the system peak demand days. This is an unlikely scenario but adjustments in rates to account for this level of uncertainty would be difficult. Uncertainties of this type are more appropriately included as a de-rating factor associated with the value of the demand response.

CPP "adders" were constructed as the avoided $85/kW-year capacity cost divided by the number of hours subject to the CPP-F peak period prices. CPP peak rates for rate schedules with fewer hours were capped at the CPP-F levels as they already exhibited a fairly high ratio relative to their otherwise applicable summer on-peak rate (6.1:1 in the case of non-AB1-X compliant CPP-F residential rates).

No customer cost differences that may occur due to this rate design were considered. For example, no additional meter costs or avoided meter reading costs were included. Estimated bill impacts were produced from our load research samples used in rate design not only to insure correct revenue neutral rate designs to class averages, but to assess the degree to which the customers might be impacted by these cost-based rates. Observing the level of bill impacts under a variety of customer response assumptions helps us to gauge customer acceptance of these rate designs. Other distinct advantages in using the rate design load research sample data include larger sample sizes and insurance against any participation bias as these accounts had their meters installed several years ago.

The results of our CPP-F rate design and bill impact analysis shows that without any load reduction during CPP events under the CPP-F scenario, the number of residential customers experiencing at least a ten percent annual bill increase is above twenty percent. Further, at the twenty percent load reduction level, about thirteen percent of residential customers still see bill increases of more than ten percent, while only about sixteen percent of our residential customers would see an annual bill decrease of at least ten percent.

Similar CPP-F bill impact analysis shows that for smaller GS-1 commercial customers, about twenty-two percent will experience annual bill increases of at least nine percent, while about twenty-six percent will experience a bill decrease of at least nine percent, assuming no load response. Assuming a twenty percent response, about thirty-one percent of GS-1 customers would see an annual bill reduction of at least nine percent, while fourteen percent would still see an annual increase of nine percent.

D. Financial Assumptions

Our key financial assumptions to develop the cost and benefit information used in the preliminary business case analysis are discussed below.

1. Labor Costs

All of our labor estimates are based on annualized Full Time Equivalent (FTE) employee requirements. Non-represented labor costs were determined by the SCE Market Reference Point for specific job titles. Represented labor costs were determined by our current labor contract for the appropriate job title. Pensions and benefits costs for health care, pension, and benefit plans were determined using marginal costs and escalation rates that are consistent with SCE's 2006 General Rate Case. Installation and meter-handling labor is allocated sixty percent to installation of new meters, and forty percent to removal of old meters. Where required, severance costs were estimated by our Human Resources Department using existing severance plans and policies. Severance is contemplated for certain positions under various scenarios, while some positions will be reduced solely through attrition. In some scenarios, additional facilities are required for added workers. Incremental facility costs for field personnel, for Customer

Communications, and for Billing staff were estimated using market lease rates for the specific required facilities.

2. Capital Costs

Capital costs for AMI meters include meters, installation labor, direct supervisory costs, and related vehicle, material, and supply costs. Tax depreciation for cash flow purposes is based on relevant Internal Revenue Service rules. Capital costs of replacing any devices (*i.e.,* servers, computers, meter batteries), whose useful lives expire between 2006-2020 are included in the analysis. Although significant capital replacements for meters, communications equipment and IT hardware would be scheduled to occur in 2021, costs for these replacements were excluded from our analysis.[36] The estimated net salvage value of $1.00 per meter has been credited against removal expense. Unrecovered capital costs at the end of 2021 are not included in the analysis, but would be recovered over future periods.[37]

3. Taxes

For cash flow purposes, we used tax rates of 35 percent for federal and 8.84% for state. Tax benefits from early write-off of the removed meters are included in the cash flow and revenue requirement analysis.

4. Cost of External Financing

The Ruling requires the utilities to evaluate various financing options for the large capital expenditure anticipated for a full deployment of AMI. Specifically, the Ruling required the utilities to evaluate both an internal financing/implementation approach as well as an outsourcing approach in which

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[36] *See* Section IV.3, Risk Assessment

[37] Unrecovered capital costs in 2021 were estimated to be approximately $19 million and $190 million respectfully for the partial (Zone 4) and full deployment scenarios.

AMI acquisition, installation, and O&M would be obtained under contractual arrangements with third-party providers.[38]

Any large contractual obligation on the part of SCE has a detrimental impact on SCE's credit rating. For any outsourcing arrangement where we are the counterparty, such as contracting to pay a third-party for fifteen years for meter installation/ownership or for meter O&M, rating agencies equate the capital lease with a debt instrument. Thus, in addition to cost of the cash payments to the third-party, capital leases appear on our balance sheet and must be offset by adding equity to the capital structure. Importantly, as will be discussed in those outsourcing business case scenarios, none of the potential AMI outsource providers demonstrated the ability to provide superior financing terms above our own notwithstanding the capital lease issue.

5. Net Present Value Analysis and Assumptions

As detailed in Volumes 3 and 4, all operating costs and benefits were estimated in 2004 dollars, and then escalated to nominal (year-incurred) dollars. Annual nominal cash flows were then summarized and discounted back to 2004 dollars using Excel's "NPV" function, with a 10.5% discount rate. All references in these volumes to "2004 NPV" or "2004 Present Value" use this approach. Demand Response benefits were analyzed using the levelized capacity and energy values specified in the Ruling.

In this preliminary analysis, we present our NPV analysis under two approaches. Under the first approach, we calculated the NPV of each scenario using a standard discounted cash flow approach. Each year's nominal costs and

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[38] *See* Ruling, Attachment A, pp. 4, 8.

benefits were summarized along with their tax impacts,[39] to produce an after-tax cash flow NPV.

The revenue requirement analysis utilized the same nominal costs and benefits, but used regulatory (or "book") depreciable lives for capital assets and included the carrying costs of new capital investments. It also incorporated the rate impact of the accelerated recovery of the existing meters, which would be removed in an AMI deployment.

The after-tax cash flow analysis demonstrates that, on a financial basis, projects with negative NPVs are a poor use of capital. The revenue requirement analysis demonstrates whether a project will have a beneficial or negative impact on customer rates.

To calculate the annualized or monthly revenue requirement impact, the annual revenue requirements for each scenario were discounted back to a 2004 present value.

6. Revenue Requirement Analysis and Assumptions

Revenue requirement impacts, including both the operating expenses and capital costs associated with AMI implementation, were assessed. SCE estimated net AMI-related revenue requirement impacts for each of the twenty-three scenarios included in its preliminary analysis[40] for years 2006 through 2021. These estimates, which are detailed in Volumes 3 and 4, were determined by subtracting expected revenue requirement reductions from estimated AMI-related revenue requirement. Revenue requirement reductions include cost savings from Customer Service-related O&M reductions, existing meter revenue requirements

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[39] Higher O&M costs and depreciation would provide a tax deduction, while demand response benefits and O&M savings produced higher taxes.

[40] *See* Table 1 of Section II – General Approach for Scenario Definitions

reductions and procurement cost reductions. AMI-related revenue requirement includes: 1) anticipated O&M expenses and capital costs associated with expected rate base amounts for new AMI-related meters and related infrastructure and 2) stranded costs associated with the undepreciated balance of existing or replaced meters, which SCE proposes to amortize over the five-year new meter deployment period. SCE estimates for the full deployment, the total project revenue requirement PV ranges from $0.794 billion for Scenario 7 to $1.287 billion for Scenario 9. For a partial deployment, SCE estimates that the total project revenue requirement ranges from $(219.7) million for Scenario 12 to $441.7 million for Scenario 14. Results are discussed in detail in Volumes 3 and 4. Revenue requirement impacts were assessed for analysis purposes only. SCE plans to provide a cost recovery or ratemaking proposal to recover the AMI-related revenue requirements as required, in our formal application.

7. Treatment of Costs not Clearly Anticipated by the Ruling

a) Pre-2006 Start-up Costs

The Ruling mandates a "2006 to 2021 analysis period,"[41] but in order to meet the five-year deployment target, some costs would have to be spent in 2005 to prepare for a 2006 rollout. These pre-2006 costs have been included in the business case scenarios as 2006 costs.

b) Stranded Costs

To implement AMI, all existing meters that do not meet the communication and interval data capabilities required by the Ruling would have to be replaced, even though those meters that still have much of their useful life left.

[41] Ruling, Attachment A, p. 12.

As of June 2004, we have approximately $318 million in undepreciated meter capital, after adjusting for the small percentage of out-of-scope meters in the Full Deployment scenarios. Accounting rules require SCE to charge the undepreciated balance of the retired meters, along with the cost of their removal (net of salvage value realized) against accumulated depreciation. This total is estimated to be approximately $380 million for the Full Deployment scenarios. We have incorporated this cost into the business case, as code "MS-9 Salvage/Disposal process for removed meters." These costs need to be recovered contemporaneously with the system installation through an appropriate cost recovery mechanism.

IV.

RISK ASSESSMENT

Any endeavor of the magnitude envisioned here will inevitably carry with it a number of uncertainties and risks. The Ruling requires the applicants to evaluate and address the key risks of AMI deployment both quantitatively and qualitatively. The extent of variation in business case scenarios addresses certain quantitative risks by assigning values to assumptions that vary widely. We further assessed the quantitative risks for each scenario by developing range estimates for most likely high and low sensitivities for each cost and operational benefit category with estimates greater than $5 million. We then used these values in statistical analyses using Monte Carlo simulation to identify the confidence levels of our estimates and potential contingency values. In each of the business case scenarios, our original estimates had very low confidence levels. We believe that a ninety percent confidence level, or the chance of not overrunning the cost, is reasonable for this type of project. As such, we should include contingency based on the statistical analysis. While we identify the respective contingency for several significant scenarios, we did not include the resulting contingency values in the cash flow analysis or revenue requirement due to insufficient time. However, we will consider including contingency for the final application.

Qualitative, or difficult-to-quantify, risks are by nature more problematic and can be addressed as a whole by setting a high financial hurdle rate or high positive NPV threshold. We believe that certain risks can be mitigated by Commission action, while others cannot. This Section is a qualitative discussion of key risk areas and what steps could be taken to reduce uncertainties.

In a general sense, we believe that full, simultaneous statewide deployment of the scale and scope envisioned in the Ruling would be a first-of-a-kind endeavor with associated uncertainties and risks. SCE is not aware of any other previous AMI deployment anywhere in the country of the size, scope, or complexity envisioned by the Ruling. We understand that in several states, utilities have undertaken fairly large AMR programs with a significant installation of electronically-read meters (similar to the more than 500,000 meters we currently read as part of our AMR program), but that these deployments are simple AMR programs (for which usage data is cumulative and the meters are read once per month), not AMI with interval meters and demand response (for which the usage data is divided into hourly or smaller intervals and collected at least daily with the capability of next-day customer access). In addition, we are aware of several projects around the country deploying certain demand response programs to residential customers, but certainly not on the scale and within the parameters and functionality of the required business case.[42] Thus, an assessment of key risk areas and what is needed to reduce uncertainties is warranted.

As described in Volume 1, SCE supports new technology and innovation as long as risks can be reasonably addressed and resolved. While there are myriad risks of varying magnitudes, we focus here only on the key risk

[42] In SCE's attempt to research other utilities' experience with AMR and price responsive rates, SCE was unable to find another utility that had deployed AMI to the scale and scope envisioned by the Ruling, and was collecting and billing on interval metering data. Although PPL Electric Utilities has deployed advanced meters to roughly 1 million customers, we understand that only a small fraction of those customers are on a price-responsive rate. Likewise, although Puget Sound Energy placed roughly 270,000 customers on a TOU rate before the program was discontinued, this program did not involve the collection, billing and storage of interval data or the complex communications infrastructure required by the Ruling.

areas that must be resolved before AMI can reasonably move forward. These areas include:

- AMI technology availability, maturity and reliability;
- Scale and scope of simultaneous AMI deployment;
- Longevity of AMI compared to other resource options;
- The uncertainty of true gains in economic efficiency;
- The existence of statutory restrictions against default price responsive rates; and
- The reliability of demand response at anticipated levels.

Each of these risk areas and what is necessary to reduce or resolve them is described below.

A. The Uncertainty Concerning the Reliability of AMI Technology Must Be Resolved for AMI to Be Successful

As noted above, we are not aware of any deployments of AMI in the United States at the scale and functionality envisioned by the Ruling. While some utilities, such as Xcel Energy, Ameren and Exelon, have deployed interval data meters communicating with a fixed network, these utilities are only collecting monthly meter read data and have not yet implemented an end-to-end integrated system that can collect and process 15-minute and hourly data and bill customers on a large-scale. As such, there are a number of technological uncertainties and risks associated with a full deployment of AMI that must be resolved before an AMI deployment could be successful.

Although interval metering has been available for some time and is a fairly proven technology with which California and other utilities have experience, the communications aspect of the AMI network is more unpredictable. Because the two-way RF communications aspect of AMI is a fairly recent innovation and thus, is largely untested in real installations, there is risk of unexpected and unpredictable delays and problems. These problems will become magnified, given the size of a full scale deployment and the speed of the Ruling's contemplated roll-out period.[43] In addition, due to the sheer size and geographic diversity of SCE's service territory, there is a chance that there may be less-than-expected coverage, which could require additional collectors and other hardware than estimated, which adds additional risk of delay and cost overruns. Moreover, some components of the infrastructure are still being developed and integrated with existing AMI network technology, so there are substantial risks that the communication hardware may not interface properly with these yet-to-be designed in-home displays (*e.g.*, for CPP notification) or load control devices.

Because of the communication aspect of the technology, if there is a technical problem resulting in a communication failure, there is the increased risk of lost data which would then require an estimated bill, therefore increasing ongoing operating costs. The complexity of collecting, validating, billing, and storing the large volume of interval data vastly increases the magnitude of work and costs involved compared to once-monthly meter reads. This increased amount of data also increases the potential for data voids and the need for billing

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[43] In SCE's deployment of RTEMs to customers with demand of 200 kW or greater, many of the defects and ensuing delays were caused by communications problems. For example, from 2001 through 2004, we have purchased 16,158 remotely communicating interval meters for the initial RTEM deployment and for the SPP, during which 7,774 (or roughly 48%) meters were returned for warranty repair (66% due to meter recalls and 34% resulting from workmanship related or material defects). The majority of trouble reports, approximately 54%, were related to communication issues, including failures in the communications modules, wireless coverage, wired phone lines, or the meter itself. These meter defects and recalls twice forced the RTEM deployment to stop altogether until the meter quality issues could be resolved, causing substantial delay in the deployment schedule of these 12,000 meters.

exceptions, which would contribute to increased ongoing operations and maintenance costs.

In addition to the risks associated with a newer technology, there is also the potential for technological obsolescence. For example, we have determined that based on today's costs and the Ruling's prescribed system requirements, the most cost-effective technological solution for AMI would be a RF hybrid mesh network. However, in a few years, one of the developing technologies, such as a power line carrier, may prove to be more reliable and cost effective, depending on technological advances and economies of scale. If eventually this or another technology proves to be a superior and lower-cost alternative to today's RF solution, there is the risk that today's investment will become stranded.

Given the attention AMI is receiving around the world and given how quickly the marketplace can adapt to technological innovations (*e.g.*, advances in computers, cellular phones, television technology, *etc*.), the possibility that there is a better, faster, cheaper and more reliable technology right around the corner is very real. As such, an additional technological risk is investing in a nascent technology too soon or at too high a cost. The metering and communications equipment vendors must demonstrate that AMI technology with the functionality specified in the Ruling is commercially available and proven before any decision on AMI deployment can be made. The Commission should exercise due care before ordering a deployment of emerging rather than proven technologies.

As described above, there are several technology challenges and substantial associated risks that are further compounded by the fact that the vast majority of AMI technologies available today are each proprietary. This means that none of the existing AMI communication technologies are not compatible. As such, a failure for a vendor or its technology to perform would mean that another vendor's technology would be required to retrofit the non-performing system. This type of event would create a significant negative financial and schedule impact.

Another considerable risk is the availability of integrated ALC functionality within the LAN/WAN/Metering architecture. Most AMI technology solutions, including that selected by SCE as the technology of choice (given the Ruling's aggressive near-term hypothetical deployment), do not yet possess commercially available hardware with related embedded ALC functionality. Although most of the vendors providing responses to our RFI proposal stated they were willing to explore development with third-party vendors, were currently working on hardware prototypes or were willing to further explore the issue without providing any details whatsoever, there are inherent risks associated with near-term true commercial availability.

For AMI to be successful, the substantial uncertainty about the reliability and cost of the technology currently available must be resolved.

B. The Uncertainty Concerning the Feasibility of a Simultaneous Statewide Deployment Must Be Resolved for AMI to Be Successful

A significant risk of full-scale deployment is the possibility that all three respondent utilities would simultaneously undertake their own mass deployments in their respective service territories. On a statewide basis, this deployment would encompass replacing more than 15 million electric and gas meters within the five-year deployment window, which would have definite impacts on the utilities' ability to manage a handful of vendors and compete for a limited supply of materials and skilled labor force. We are not aware of any other AMI or AMR deployment in the United States even close to this magnitude that involves the same level of complexity in system functionality and operational requirements, and thus, we question whether the vendors are or will have time to become prepared for a mass deployment starting in 2006.[44]

Specifically, simultaneous statewide full deployment by the utilities would likely stress the metering equipment vendors' ability to deliver materials on time and to handle component failures quickly. During the deployment of approximately 12,000 RTEMs during the energy crisis, we experienced a number of delays in obtaining a sufficient supply of meters to keep pace with the installation schedule and several significant delays in getting numerous technical defects corrected.[45] On a statewide basis, the five-year deployment window will require the installation of more than 12,000 meters per day.[46] Any delay in meter availability or quality control problems will quickly create an enormous backlog and hinder such a deployment.

The aggressive five-year full-scale deployment window also poses several challenges which could be multiplied on a statewide basis. Ideally, the installation of the communications network should precede the installation of meters so that the communications link can be verified at the time the meter is installed. To roll out the required volume of meters within the prescribed time-frame, however, meter installations will need to commence prior to the completion of the communications network and back office system interfaces. As such, when these initial meters are installed, there is no way to know until the network is operational whether the meters can communicate properly or whether additional communications hardware will be required. As a result, there will be

[44] The only meter deployment that is in this range is for the Italian Utility Enel where 30 million meters are being installed. This national program involved a unique meter design and we do not have specific information as to its functionality.

[45] Our 12,000 RTEM installations were anticipated to take one year, but the actual installation period due to these meter availability problems and product defects causing meter recalls was stretched to two years.

[46] Based on roughly 15 million gas and electric meters statewide, assuming a five-year deployment and a five-day work week.

the need for additional return visits to investigate and repair communications failures.

Given this substantial uncertainty concerning the feasibility of a simultaneous statewide deployment, it may not be prudent for California to undertake a simultaneous statewide installation because if there are problems, they would likely occur threefold. One way to mitigate these risks would be to do a staged deployment, with one utility deploying first and the other utilities deploying with the benefit of the lessons learned and experience gained from that first deployment. A simultaneous statewide deployment essentially puts "all of the eggs in one basket" by imposing the risks of AMI deployment across the entire state, instead of taking a more cautious phased-in approach, which would reduce these risks and uncertainties before full scale statewide deployment.

C. <u>The Uncertainty of the Longevity of the AMI System Compared to Other Resource Options Must Be Considered</u>

In moving to an AMI system, meters will have solid state technology, which is a newer technology with sensitive electronic components. The generally-accepted lifespan for solid state meters and meters with electronic components is fifteen years, compared to the industry-average lifespan of thirty years for mechanical meters (*i.e.*, those currently in use today for the majority of residential customers). This shorter lifespan of the AMI meters will require more frequent replacement of meters and network components than we currently experience, including a large "bubble" beginning fifteen years after the AMI implementation, where many, if not all, AMI meters will again have to be replaced.

Assuming a 2006 start date for AMI systems installation, this fifteen-year lifespan of solid state meters would mean that we would have to begin replacing meters in mass no later than 2021, which is the end of the Ruling's business case analysis period of 2006 through 2021. These start-up and installation activities would include materials procurement and the hiring and training of supplemental installation staff, plus likely installation of some actual meters, depending on the roll-out plan developed at that time.[47]

In addition, having gone down the path of AMI, there are other non-metering hardware aspects of the infrastructure, such as communication network or IT hardware that would also need to be refreshed throughout the Ruling's sixteen-year analysis period (2006-2021) in order to maintain the AMI system. Some non-metering hardware components, such as our field data collection infrastructure,[48] also have a fifteen-year lifespan and would have to be refreshed in 2021 in order to be capable of continuing to support AMI. Other hardware components necessary for AMI, including servers and related software, have a five-year refresh cycle, and assuming installation beginning in 2006, will have a necessary refresh cost in 2011 and 2016. These hardware components would also necessarily have to be refreshed in 2021 after the next five-year refresh cycle in order to continue to support AMI going past the Ruling's analysis period.

These significant replacement costs for metering and non-metering hardware that will necessarily be incurred in 2021 have *not* been included in the

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[47] Given the estimated failure rate of the meters under a full scale meter deployment, a certain number of meters (estimated to be roughly 31%) will likely have already been replaced well before the fifteen-year lifespan has expired, and thus, SCE anticipates that it would only need to replace those remaining meters nearing the end of their anticipated fifteen-year life and continue this process over time. Depending on the number of failed meters actually replaced, it is possible that SCE could design its second AMI deployment plan accordingly either to (i) proactively replace 100% of the meters including meters that might only be a few years old, or (ii) replace the meters in piecemeal fashion as they actually fail, recognizing the possibility of extremely high number of failures within a shorter duration and the associated customer and billing impacts.

[48] *See* Section 3(a) AMI Technology Assumptions

current analysis even though they will be incurred during the Ruling's required analysis period (2006-2021). The estimates regarding the possible costs for these anticipated activities are highly uncertain, given that they are more than fifteen years away, and technological advances might result in deploying a different technology that is not available or cost effective today. Some costs are expected to increase over time, such as labor, but others could possibly decrease, such as the cost of technology. Thus, it is too uncertain to even begin to project the cost implications of the second wave of AMI installations beginning in 2021 with any precision. Moreover, because we are not counting the potential benefits to be derived from the future wave of AMI deployments in this analysis, we decided it is most comparable to leave these refresh costs out of the analysis, despite the fact that dealing with the post-2021 bubble of meter and related hardware replacements will cause very significant costs during the 2006-2021 business case analysis period. Thus, the shorter estimated lifespan of AMI meters and other hardware creates significant uncertainty regarding the true costs of AMI compared to other resources that have a longer lifespan and more predictable maintenance record. For AMI to be successful and to be a cost-effective resource among other resource options, these uncertainties must be resolved so that the full costs of AMI can be compared to other resources.

D. The Uncertainty of Economic Efficiency Gains and Societal Benefits Should Be Considered

Although TDRs may induce certain customer behaviors producing demand reductions, it is difficult to assess whether such behaviors directly translate to economic or societal gains. As noted in Volume 1, one of the fundamental requirements for AMI to be successful is that dynamic pricing tariffs must approximate actual market prices, rather than be designed solely to elicit demand response. To meet this principle, it is imperative that the uncertainty in the development of a functioning electricity market that is capable of providing appropriate price signals be resolved.

Second, if rates only approximate actual market prices some of the time and signal customers with wrong prices the rest of the time, there could be perverse and undesirable outcomes. Generally, economists want prices to be "just right" for maximum economic efficiency. This is a noble, but elusive goal in regulatory ratemaking. Only real-time retail prices that track wholesale prices in a functioning wholesale market will accomplish that goal. Rates such as CPP, TOU or tiered rate designs designed to track market prices must necessarily be designed to recover a utility's overall revenue requirement. This "second best" adjustment may interfere with the efficiency of these rates. In addition, there is no readily available source for market prices today. The ISO maintains a real-time market today, but there are significant questions about whether this would provide an appropriate measure due to the small volume traded, the influence of large quantities of bilateral contract obligations (principally the California Department of Water Resources (CDWR) contracts), and ongoing ISO market-redesign efforts to incorporate capacity and locational pricing.

Third, the actual avoided costs of generation from demand response will change depending on the market. Recently, the Commission has ordered load serving entities to maintain a fifteen percent reserve requirement to ensure resource adequacy. This requirement will force SCE to have sufficient capacity to meet 115 percent of its peak demand, which is intended to alleviate energy and capacity shortages. We anticipate that as a result of these resource adequacy requirements, the overall market will stabilize, therefore producing less variation in prices between peak and off-peak periods and reducing the frequency and effect of CPP days. With this market stabilization, we would expect the marginal costs of energy to also stabilize, thereby reducing the differential between on-peak and off-peak rates. Reducing the differential would also reduce expected price-induced demand response.

E. The Uncertainty of the Existence of Statutory Restrictions Against Price-Responsive Rates Must Be Resolved for AMI to Be Successful

The Ruling requires the utilities to analyze several different tariff structures in an effort to determine the costs and benefits associated with the deployment of AMI.[49] The Ruling recognizes, however, that in the near term, legislative constraints on rate design modifications may have a considerable impact on the benefits derived from the full scale deployment of AMI.[50] The legislative constraint alluded to in the Ruling is the result of Section 80110 of the California Water Code enacted by AB1-X as a result of the 2000-2001 energy crisis. Section 80110 prohibits the Commission from increasing any electricity charges for residential customers' usage of up to 130 percent of their existing baseline allowances. This prohibition is in place until the CDWR power contracts expire, which is currently expected to occur in 2013.[51]

As the Ruling recognizes, the rate design restrictions required by Section 80110 will impede the ability to derive substantial benefits from the demand response full deployment scenario in the years prior to 2014. This is because rates simply cannot be designed to reflect critical peak or time-of-use price signals for a residential customer's entire usage given that those customers' usage up to 130 percent of baseline could not be subject to a dynamic price. In

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[49] Ruling, Attachment A, pp. 4-5, 10.
[50] Ruling, p. 3.
[51] This sunset is based on the assumption that AB1-X is in effect until the last CDWR power contract expires, which is presently 2013.

fact, a residential customer using less than 130 percent of its baseline allowance would never be charged time-of-use or critical peak prices due to the constraints of Section 80110. As a result, any demand response contributions these customers could make will never be realized and thus, the AMI benefits will be reduced.

In clarifying the demand response scenario analytical framework laid out by the Ruling, we were instructed in the WG3 process to use the assumption that the requirements of Section 80110 do not exist. While using this clarification allows for application of dynamic prices to residential customers, it violates the requirements of Section 80110. Thus, the demand response analysis results derived from the experimental CPP programs and used in the required business case scenarios are overstated because there is no indication that Section 80110 will definitely be repealed prior to its sunset in 2013.

We are concerned about inappropriately using analytical results based on rate structures that do not comply with the law, given that the analysis will incorrectly account for demand response that cannot occur as long as Section 80110 is in effect. If Section 80110 remains in place as well as the Commission's current interpretation thereof, dynamic pricing schedules under a default or mandatory tariff enrollment would not be allowed until 2014. Therefore, in those cases, demand response benefits would not occur until 2014, drastically reducing the potential demand response benefits of AMI.

The CEC staff recently suggested that Section 80110 could be interpreted to apply to monthly bills rather than rates. We have not analyzed how price differentiated tariffs would work nor what the effect would be on demand response under this alternative interpretation other than it would still be very problematic. About seventy percent of SCE's residential kWh sales is to customers with monthly usage at or below 130 percent of their baseline allowance. It is not clear how a dynamic rate program would apply to customers whose monthly bill is capped. Also, it is not clear how dynamic prices would apply to customers whose usage is near the 130 percent threshold. How would they respond to a dynamic price that may or may not increase their monthly bill? Finally, the SPP experiment did not cover a scenario or rate design with AB1-X in place, so the elasticity effects and load reductions from the experiment are significantly overstated unless the restrictions are removed.

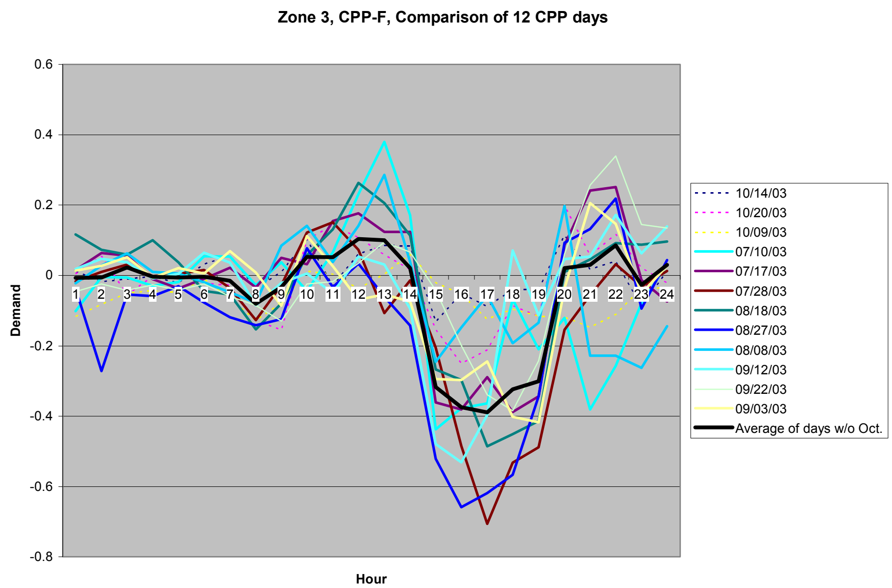
F. The Reliability of Demand Response Must Be Better Understood

The highest-value benefit of demand response is the reduction in the system's peak load. TDRs can induce customers to change behaviors and forego levels of comfort in a way that reduces their electricity usage in peak periods. The total amount of demand reduction from TDRs is the result of two key factors: (1) the customers' collective usage reductions coincident with system peak, and (2) the number of customers on TDRs. As described in the assumptions section above, both of these factors are highly uncertain and will remain so until many years of experience are gained with TDRs. Until these uncertainties are resolved, the level and reliability of demand response cannot be accurately predicted.

It may take many years of experience to determine a reliable amount of load reduction and the persistence of that reduction over time. At the low end of the range, it can be argued that "countable" demand response from a new CPP rate should be near zero percent until proven to be durable and reliable. If customer acceptance of CPP rates is unknown and regulatory policy concerning AB1-X could cause the utilities to withdraw such rates due to customer complaints, then load reductions must be highly discounted or de-rated until such risks can be mitigated. At the high end of the range lies the assumption that price-responsive demand response is as reliable and callable as a combustion turbine and should not be de-rated at all. The likely outcome lies somewhere in between, but the uncertainty regarding the reliability of demand response will impact the value it brings to the resource portfolio.

The day-to-day variation of customer response to TDRs has not been determined. To get a sense of the variation between days, we calculated the estimated savings for each CPP day during the summer of 2003 using the "difference of differences" method described in the CEC report "Response of Residential Customers to Critical Peak Pricing and TOU Rates During the Summer of 2003." We illustrate these data in Figure 2-2 below. Note that while nearly all CPP days in July-September show savings, there is a great deal of variation in the level of savings for each day. Some of this variation is probably due to weather, but there may be other factors as well.

Figure 2-2
Comparison of CPP Days in Zone 3



The results of SPP for 2004 may provide additional information but it is likely that many years of experience with TDRs will be necessary to improve the reliability of forecasting demand response to TDRs.

Appendix A

Estimating Preliminary Demand Savings from Potential Two-Part Real Time Pricing

APPENDIX A

ESTIMATING PRELIMINARY DEMAND SAVINGS FROM POTENTIAL TWO-PART REAL TIME PRICING

This Appendix describes how SCE developed a preliminary estimate of the MW savings at system peak from firm and interruptible customers who would potentially be on the two-part RTP rates. Our basic approach was to start with the results of the study that Christensen Associates performed for the California Energy Commission (CEC)[52] to estimate the statewide savings due to the potential implementation of RTP across the three major investor-owned utilities (IOUs) in the state. We applied those results, by Standard Industrial Classification (SIC) code, to the population of SCE customers with peak demands over 200 kW.

We considered two scenarios, one in which all customers over 200 kW were moved to an RTP tariff, and one in which those customers currently served on an interruptible rate (I-6) remained on the interruptible rate and those served on any of the firm rates were moved to an RTP tariff.

A. Description of the Christensen Report

The Christensen report was based primarily on an analysis of Georgia Power's RTP program, serving about 1,600 large C&I customers. The analysis showed that the degree of price-responsiveness to RTP rates was related to SIC code. The report provides a list (Table 2 in the report) of 18 SIC codes that were found to be price responsive to some degree. For each SIC code, the report further disaggregated these groups into high, moderate, and low responders, and provided the percentage of Georgia Power customers that had each level of responsiveness for

[52] Potential Impact of Real-Time Pricing in California, by Steve Braithwait and David Armstrong (Christensen Associates), January 14, 2004.

each SIC code. The report provided one elasticity parameter (the peak-period elasticity of substitution) for each responsiveness level for each SIC code.

Using statewide population information, PG&E's dynamic load profiles, historic rates, and historic "pre-energy crisis" wholesale costs, Christensen estimated the total statewide load savings at the system peak for each SIC code, for both a "very high price day" and a "high price day." The load savings by SIC code, both on an absolute and a percentage basis, is shown in table 4 of the report. Note that these savings (a total of 814 MW, or about 17% of the total load for the group on the very high price days) represent the expected statewide savings.

B. <u>Determining Impacts on SCE's System Peak</u>

In order to determine the impact on SCE's system peak from SCE's customers with peak demands over 200 kW, we first summarized the contribution to the system peak for these customers by SIC code and rate (including firm vs. interruptible). We then applied the percent load savings for each price-responsive SIC Code from table 4 of Christensen's report, using the very high price day information (in order to reflect the load likely to be dropped on extreme days), and totaled the load reductions across the SIC codes to estimate the total load reductions that SCE can expect if RTP tariffs are applied to all customers over 200 kW. Those SIC codes that were not listed in the report were not price responsive, so we assumed that there would be no load reduction by SCE customers in those SIC groups.

Most of the current SCE population of customers with demand over 200 kW already have interval data recorders, but some do not. Contribution to the 2003 system peak data were available for 10,585 of these customers, and 1,170 customers did not have interval data at that time. For the customers with interval data available, we used the actual contribution to the system peak hour. For those customers without interval data we applied the rate class average coincidence factor for September 2003 to their September 2003 billing demand to estimate the contribution to the system peak hour. The actual demands and the estimated demands were then combined to provide results for the entire population of customers with demands over 200 kW.

We did not include agricultural (AG&P) customers in this analysis. We could find no evidence of agricultural customers being served on RTP rates anywhere in the literature, so there was nothing upon which to base the calculations.

We then split the SCE load for customers with peak demands over 200 kW into two groups, interruptible and firm, in order to estimate the load reduction if the firm customers were moved to the RTP Tariff and the interruptible customers were left on their current interruptible rates. This required making a few additional assumptions. The first was that the interruptible customers would be in the high responding part of each SIC code group. This was based on the fact that they were already curtailing a significant amount of load when called to do so, so they were certainly capable of responding. The interruptible load for some of the SIC code groups was more than the percent of high responders from the Christensen report, so in those cases, we assumed that all of the high responders in the SIC group were interruptible, and part of the moderate responders were interruptible as well.

C. <u>Determining Load Reductions by SIC Group</u>

The Christensen Report did not provide the load reductions by response level either in the aggregate or for individual SIC code groups. We contacted Christensen to ask for the reductions by response level, but they were not able to provide this in the short time frame necessitated by the AMI business case filing schedule. Thus, we made one additional assumption. Because the Christensen Report did provide the peak-period elasticity of substitution for each response level within each SIC code group, we made the simplifying assumption that the load reductions in the high and moderate responding groups were proportional to the peak-period elasticity of substitution for the groups. Based on the Georgia Power results, the elasticity in low responding groups is zero. Therefore we assume that there is no load response among this group. As such, there is enough information to allocate the load response by SIC code group to the high and moderate responders. The assumptions used are described in the following three equations:

$$totpctsavings = pctsavings_h \cdot pct_h + pctsavings_m \cdot pct_m + pctsavings_l \cdot pct_l$$

$$\frac{pctsavings_h}{pctsavings_m} = const = \frac{elasticity_h}{elasticity_m}$$

$$pctsavings_l = 0$$

In this formula, "*totpctsavings*" is the total savings for the SIC code group, expressed as a percent, "*pct*" is the percent in the SIC group for each response level, "*const*" is the ratio of the high responder elasticity parameter to the moderate responder elasticity parameter for the SIC group, "*elasticity*" is the elasticity parameter, and "*pctsavings*" is the estimated percent savings for each response level. The subscripts indicate the response level of high, moderate, or low.

Based on these relationships, for each SIC code group, we estimated the percent reduction by response level for the moderate and high responding groups as follows.

$$totpctsavings = const \cdot pctsavings_m \cdot pct_h + pctsavings_m \cdot pct_m + 0 \cdot pct_l$$

$$pctsavings_m = \frac{totpctsavings}{(const \cdot pct_h + pct_m)}$$

$$pctsavings_h = const \cdot pctsavings_m$$

Once the percentage reductions for each SIC group was estimated in this way, we applied those percentage reductions to both the interruptible and firm loads for each SIC group and each response level. We then aggregated the firm loads together and the interruptible loads together, to get total estimated reductions from each group.

Appendix B

Estimating the Value of Service Loss

APPENDIX B

ESTIMATING THE VALUE OF SERVICE LOSS

This appendix describes the method we used to estimate the value of the loss of service as described in Section IV of this volume from all the ratepayer perspective. We used the Standard Practice Manual's (SPM) definition of the all-ratepayer or societal perspective as a measure of overall economic efficiency. The participant and other ratepayer perspectives address the distributional (cost shifting) impacts of a program. The participant perspective can also be helpful in the design of appropriate incentives. The SPM equations can be written as follows:

Table 2-15
Standard Practice Manual Perspectives

	Participant Perspective	Other Ratepayer Perspective	All Ratepayer Or Societal Perspective
Benefits	Bill Savings	Resource Cost Savings Operational Savings Metering Charge Revenues	Resource Cost Savings Operational Savings
Costs	Value of Service Loss Metering Charges	Participant Bill Savings AMI Costs DR/DP Admin Costs	AMI Costs DR/DP Admin Costs Value of Service Loss

SCE used this analytical framework for evaluating advanced metering infrastructure investments.

A. Description of the Estimating Method

We have presented the various business case analyses set forth in Volume 2 using the "all ratepayer" perspective, in order to emphasize economic efficiency. Cases are presented both with and without customer value of service loss to show the effect that this variable has on the analysis results. Consideration of distributional impacts is better addressed in the design of individual pricing demand response programs. It should be noted, however, that because these programs improve the accuracy of price signals which customers receive, any distributional impacts will, in general, reduce the level of cross-subsidy which is imbedded in current rate designs.

B. Calculation of Value of Loss of Service

Value of service loss can be calculated based on information on customers' response to dynamic pricing derived from the recent pilot studies. Consider a situation where the price of energy in a peak period increases from a flat-rate of fifteen cents to a "real time price" of twenty-five cents as a result of a dynamic pricing program, and a customer reduces monthly consumption by 100 kWh as a result. We know from this behavior response that the customer values the use of this electricity by a minimum of fifteen cents, but less than twenty-five cents. If the customers' demand response is linear (straight line) then the average value that the customer would have received from the 100 kWh reduced usage is twenty cents, the simple average of the flat rate and real time price. Therefore, we can infer a value of $20 to the foregone consumption (twenty cents times 100 kWh).

This approach is consistent with the economics literature addressing time of use and real-time pricing. Acton and Bridger,[53] and Borenstein, Jaske and Rosenfeld,[54] discuss a general societal welfare (benefit) analysis that includes customer value of service impacts. The resultant change in social welfare from a change in pricing strategy from flat rate to time of use or real time rate is shown by the equation:

$$\Delta \text{ Societal Benefit} = -\tfrac{1}{2}\Delta P_1 \Delta Q_1 - \tfrac{1}{2} \Delta P_2 \Delta Q_2$$

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[53] Acton, Jan Paul and Bridger M Mitchell. "Welfare Analysis and Electricity Rate Changes," The Rand Foundation Note # N-2010-HF/FF/NSF, May 1983.

[54] Borenstein, Severin, Michael Jaske, and Arthur Rosenfeld. "Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets", University of California Energy Institute, Center for the Study of Energy Markets, October 2002, CSEM Working Paper # 105.

The ΔPs represent the change in prices and the ΔQs represent the change in quantity. This formula is based on two time periods, but generalizes to any number of periods. Because price and quantity change move in opposite directions (an increase in price decreases usage), overall societal benefit is increased by moving to time-of-use or real time pricing. Using similar nomenclature, where P_1 and P_2 are the time-of-use or real time prices, resource cost savings and value of service loss can be expressed as follows:

Δ Resource Cost Savings = $-P_1 \Delta Q_1 - P_2 \Delta Q_2$

Δ Value of Service Loss = $-(P_1 - \frac{1}{2} \Delta P_1 \Delta Q_1) - (P_2 - \frac{1}{2} \Delta P_2 \Delta Q_2)$

Given that the objective of time of use or real time pricing is to set rates equal to incremental resource costs associated with consumption, the change in resource costs is given by $P\Delta Q$. Value of service loss is calculated as described above, the average of flat rate and time of use prices times the change in quantity. Subtracting value of service loss from resource cost savings results in the equation for societal benefit shown above.

C. <u>Results of Calculation</u>

The values that result from the calculation method above are contained in the following table.

Table 2-16
Value of Service Analysis Impacts on Demand Response Benefits by Business Case Scenario
($2004 Present Value in Millions)

(1)	(2)	(3)	(4)=(2)+(3)	(5)	(6)	(7)=(5)+(6)-(4)
Scenario	Value of Service Loss - On-Peak	Value of Service Benefit - Off-Peak	Net Value of Service Loss Effect*	DR-1 Benefit	DR-2 Benefit	Impact = DR-1 + DR-2 - Net Value of Service Effect*
3	$115.0	($14.4)	$100.5	$191.8	$24.1	$115.4
4	$377.6	($38.0)	$339.6	$579.7	$79.5	$319.6
5	$81.9	($0.3)	$81.6	$142.7	$20.1	$81.2
6	$91.1	($9.2)	$81.8	$140.4	$19.3	$77.9
7***	$377.6	($38.1)	$339.6	$701.7	$97.6	$459.8
8***	$81.1	($0.3)	$80.9	$509.3	$71.3	$499.8
9	$51.6	($14.4)	$37.1	$174.2	$0.0	$137.0
10	$252.2	($25.0)	$227.3	$285.5	$0.0	$58.3
11***	$252.2	($25.0)	$227.3	$386.8	$0.0	$159.6
12**	**	**	**	$206.9	$31.0	$237.9**
13**	**	**	**	$408.4	$61.3	$469.7 **
16	$14.0	($3.2)	$10.8	$25.0	$3.1	$17.3
17	$36.6	($3.7)	$32.9	$67.5	$9.2	$43.8
18	$10.4	($0.1)	$10.4	$18.8	$2.7	$11.0
19	$11.6	($1.0)	$10.5	$20.5	$2.8	$12.7
20***	$10.4	($0.1)	$10.4	$386.2	$53.8	$429.6
21***	$11.6	($1.1)	$10.5	$387.9	$54.0	$431.4
22	$6.3	($0.8)	$5.5	$34.4	$0.0	$28.9
23	$25.1	($3.0)	$22.1	$44.2	$6.5	$28.6

* Totals may not add due to rounding error.

** Value of service loss also applies to this scenario but has not yet been calculated.

*** Value of service loss for the ALC portion of demand response also applies but has not been calculated.

Appendix C

Rate Design and Bill Impact Analysis

APPENDIX C

RATE DESIGN AND BILL IMPACT ANALYSIS

This Appendix describes the process we employed to design the experimental/existing CPP rate structures. This Appendix also describes our approach to and results of our analysis of bill impacts expected from these experimental CPP rate structures.

A. Rate Design Process

1. Domestic (Residential) Rate Design Process

Two sets of residential rates for the AMI business case scenarios were developed to be revenue neutral to the Schedule D energy charges. No changes were made to customer charges. AMI residential rates are based on a six-month summer, and six-month winter season, consistent with the existing SPP experimental rate structures, with the exception of CPP-P, which is an overlay of existing residential tiered rate structure with a four-month summer, and eight-month winter season.

A default two-part D-TOU-2 rate was developed with an on-peak period of 2:00 p.m. to 7:00 p.m., summer and winter weekdays, and all other hours as off-peak. This structure is consistent with existing experimental SPP time periods, and is used as the basis for CPP-F and CPP-V rate design. All rates were constructed to be revenue neutral to Schedule D, assuming no load alterations. Two sets of residential rates were constructed for analytical purposes, the first compliant with AB1-X provisions, and the second ignoring the AB1-X restrictions. In the non-AB1-X compliant rates, the TOU rates along with their CPP components would be more clearly understood by customers since they would understand exactly what the cost of electricity is at any point in time. Designing rates compliant with AB1-X restrictions with usage below 130 percent of baseline not subject to CPP or TOU pricing and usage above 130 percent of baseline subject to dynamic pricing would be extremely confusing to customers as it would be difficult for a medium-usage customer to respond to CPP prices if only a pro-rated portion of its above-baseline consumption were subject to the CPP rate. Customers using less than their baseline allowance would never actually be charged the CPP rate, which would eliminate any demand response contributions they could make. During the twelve-month period ending April 2004, seventy-four percent of SCE's residential customers' usage was billed at or below 130 percent of baseline (Tiers 1 and Tier 2). In fact, about thirty-four percent of residential customers never exceeded their Tier 2 usage levels, meaning a significant portion of customers would be exempt from participating in CPP rates in an AB1-X compliant case.

For both sets of rates, the existing D-TOU-2 rate option[55] is used as a basis for TOU rate design. The CPP Event rate was based on the D-TOU-2 summer on-peak energy rate, plus an approximate $1.1333 per kWh ($85 prescribed avoided peak demand cost divided by seventy-five hours) adder. Because this CPP peak rate is significantly above the CPP Pilot rate, it established the cap on the CPP rate (even though the reduced number of CPP hours assumed in the CPP-V rate would demand an even higher CPP rate using the same methodology).

The D-TOU-CPP-F rate was modeled after the existing experimental TOU-D-CPP-F rate and assumes twelve Summer Peak days and three Winter Peak days at five hours per CPP Event day, for a total of seventy-five CPP hours annually. The D-TOU-CPP-V rate was also modeled after the existing experimental TOU-D-CPP-F rate using twelve Summer Peak days and three Winter Peak days with only three hours per CPP Event between the hours of 2:00 p.m. to 5:00 p.m., for a total of forty-five CPP hours annually. The D-TOU-CPP-P rate used the basic

[55] D-TOU-2 is a modified form of TOU-D-1 to account for variations of seasonal and peak period designations

tiered residential rate with a CPP adder based on twelve Summer Peak days and three Winter Peak days at five hours per CPP Event, for a total of seventy-five CPP hours annually. In all scenarios, the added revenue resulting from high priced CPP events reduces the remaining non-CPP rate levels to maintain revenue neutrality.

2. GS-1 Rate Design Process

All Small Commercial customers' rates for the AMI business case scenarios were developed revenue neutral to the Schedule GS-1 energy charges. No changes were made to customer charges. These rates are based on a four-month summer, and eight-month winter season, consistent with the existing CPP experimental rate structures.

A default two-part GS-1-TOU-2 rate was developed with an on-peak period of noon to 6:00 p.m., summer and winter weekdays, and all other hours as off-peak. This structure is consistent with existing experimental CPP time periods. This default rate was constructed revenue neutral to the existing GS-1 rate, and used the existing GS-1-TOU option as a basis for TOU rate design.

The CPP Event rate was based on the summer on-peak energy rate, plus a $0.9444 per kWh ($85 divided by ninety hours) adder. Similar to the residential rate structures, this CPP event rate is used for GS-1-CPP-F and GS-1-CPP-V, and GS-1-CPP-P rate schedules. GS-1-CPP-F was modeled after the existing experimental GS-1-CPPV rate using twelve Summer Peak days and three Winter Peak days at six hours per CPP Event, for a total of ninety CPP hours annually.

GS-1-CPP-V was modeled after the existing experimental GS-1-CPPV rate, based on twelve Summer Peak days and three Winter Peak days with three hours per CPP Event between the hours of 2:00 p.m. to 5:00 p.m., for a total of forty-five CPP hours annually.

GS-1-CPP-P was based on twelve Summer Peak days and three Winter Peak days at six hours per CPP Event, for a total of ninety CPP event hours annually. To preserve revenue neutrality, the added revenue resulting from CPP events resulted in a reduction to the OAT energy charges.

3. <u>GS-2 Rate Design Process</u>

All Medium Commercial customers' rates for the AMI business case scenarios were developed revenue neutral to schedule GS-2 energy charges. No changes were made to the demand or fixed charges. These rates are based on a four-month summer and eight-month winter season, consistent with existing GS-2-CPP rate structure but with the additional allowance of CPP events occurring in the winter season.

The existing (revenue neutral) GS-2-TOU rate option is used as the TOU default, thus no default two-period TOU rate structure was developed for this rate class. The CPP Event rate is based on the GS-2-TOU summer on-peak energy rate, plus a $0.9444 per kWh ($85 divided by ninety hours) adder. The resulting CPP event rate is used for GS-2-CPP-F, GS-2-CPP-V, and GS-2-CPP-P rate schedules.

GS-2-CPP-F is modeled after the existing GS-2-CPP rate, with the exception of adding winter CPP events, and includes twelve Summer Peak days and three Winter Peak days at six hours per CPP Event, for a total of ninety CPP hours annually. GS-2-CPP-V is modeled after the existing GS-2-CPP rate using twelve Summer Peak days and three Winter Peak days at three hours per CPP Event between the hours of 2:00 p.m. to 5:00 p.m., for a total of forty-five CPP hours annually. GS-2-CPP-P is based on twelve Summer Peak days and three Winter Peak days at six hours per CPP Event, for a total of ninety CPP hours annually. The added revenue resulting from CPP events at the CPP rate was offset by a fixed percentage reduction to the other GS-2-TOU energy charges.

Rates used in the business case analysis are:

Table 2-17
Rates Structure for Preliminary Analysis

DOMESTIC			
D-TOU-2-Basis		Rate	
Summer	On	0.28026	<<= 6 Month, 2pm-7pm On-Peak
	Off	0.11566	
Winter	On	0.13133	<<= 6 Month, 2pm-7pm On-Peak
	Off	0.1099	
CPP-F		Rate	
CPP Event			
Summer	On	1.41359	<< = 12 Summer Top Peak Days @ 5 hours/Day, 2 pm-7 pm
Winter	On	1.41359	<< = 3 Winter Top Peak Days @ 5 hours/Day, 2 pm-7 pm
Non-CPP Event			
Summer	On	0.22816	
	Off	0.09416	
Winter	On	0.11864	
	Off	0.09928	
CPP-Pure			
CPP Event		Rate	
Summer	On	1.41359	
Winter	On	1.41359	
CPP-V			
CPP Event		Rate	
Summer	On	1.41359	<< = 12 Summer Top Peak Days @ 3 hours/Day, 2 pm-5 pm
Winter	On	1.41359	<< = 3 Winter Top Peak Days @ 3 hours/Day, 2 pm- 5 pm
Non-CPP Event			
Summer	On	0.24991	
	Off	0.10313	
Winter	On	0.12413	
	Off	0.10388	
GS-1			
GS-1-TOU-2-Default		Rate	
Summer	On	0.34731	<<= 4 Month, Noon-6pm On-Peak
	Off	0.10982	

Winter	On	0.11614	<<=8 Month, Noon-6pm On-Peak
	Off	0.10706	

CPP-F

CPP Event		Rate	
Summer	On	1.28731	<< = 12 Summer Top Peak Days @ 6 hours/Day
Winter	On	1.28731	<< = 3 Winter Top Peak Days @ 6 hours/Day
Non-CPP Event			
Summer	On	0.28254	
	Off	0.08934	
Winter	On	0.10478	
	Off	0.09658	

CPP-Pure

CPP Event		Rate
Summer	On	1.28731
Winter	On	1.28731

CPP-V

CPP Event		Rate	
Summer	On	1.28731	<< = 12 Summer Top Peak Days @ 3 hours/Day, 2 pm-5 pm
Winter	On	1.28731	<< = 3 Winter Top Peak Days @ 3 hours/Day, 2 pm - 5pm
Non-CPP Event			
Summer	On	0.31511	
	Off	0.09964	
Winter	On	0.11069	
	Off	0.10203	

GS-2

GS-2-TOU-2-Option/OAT		Rate
Summer	On	0.12796
	Mid	0.09435
	Off	0.08484
Winter	Mid	0.09921
	Off	0.08484

CPP-F		Rate	
CPP Event			
Summer	Noon-6pm	1.06796	<< = 12 Summer Top Peak Days @ 6 hours/Day
Winter	Noon-6pm	1.06796	<< = 3 Winter Top Peak Days @ 6 hours/Day
Non-CPP Event			

Summer	On	0.10463	
	Mid	0.07715	
	Off	0.06937	
Winter	Mid	0.08285	
	Off	0.07085	
CPP-Pure			
CPP Event		Rate	
Summer	On	1.06796	
Winter	On	1.06796	
CPP-V		Rate	
CPP Event			
Summer	Noon-6pm	1.06796	<< = 12 Summer Top Peak Days @ 3 hours/Day
Winter	Noon-6pm	1.06796	<< = 3 Winter Top Peak Days @ 3 hours/Day
Non-CPP Event			
Summer	On	0.11646	
	Mid	0.08587	
	Off	0.07722	
Winter	Mid	0.09127	
	Off	0.07805	

A. Bill Impact Analysis

1. Residential Bill Impacts

Residential bill impacts, which are incorporated into the MMI simulation tool, provide the basis for estimating customer adoption rates for TDRs for Opt-in scenarios. Additionally, an understanding of bill impacts is necessary to gauge future program success.

As part of the revenue neutrality component in the rate design process, SCE computed average bills for each of the nearly 3,300 customers in its load research residential rate group sample. After applying the relevant sampling weights, rates were scaled to insure that the total bills recovered the same revenue for each customer class. The larger load research sample was used instead of the

SPP sample data to gauge these impacts through the use of a larger sample size and to eliminate any impact of participation bias.

Figure 2-3 below displays the distribution of bill impacts for the CPP-F, CPP-V, and TOU rates versus the current tiered Domestic rate for the residential customer class assuming no price-induced demand response. Although the revenue-neutral rate design arithmetically centers the distribution around zero, the relatively wide distribution of bill impacts is brought about by a more equitable cost allocation by the CPP rate structures in two ways. First, the elimination of AB1-X price cap results in low usage customers experiencing the largest percentage bill increases. Most of the nearly fifteen percent of customers experiencing an annual bill increase of at least fourteen percent are lower usage customers (see Table 2-18). Second, those customers residing in the hotter weather zones using higher amounts of high cost summer on-peak energy also see bills commensurate with their (higher) cost (see Table 2-19).

Figure 2-3
Annual Bill Impacts for Residential Customers – Assuming No Load Reductions

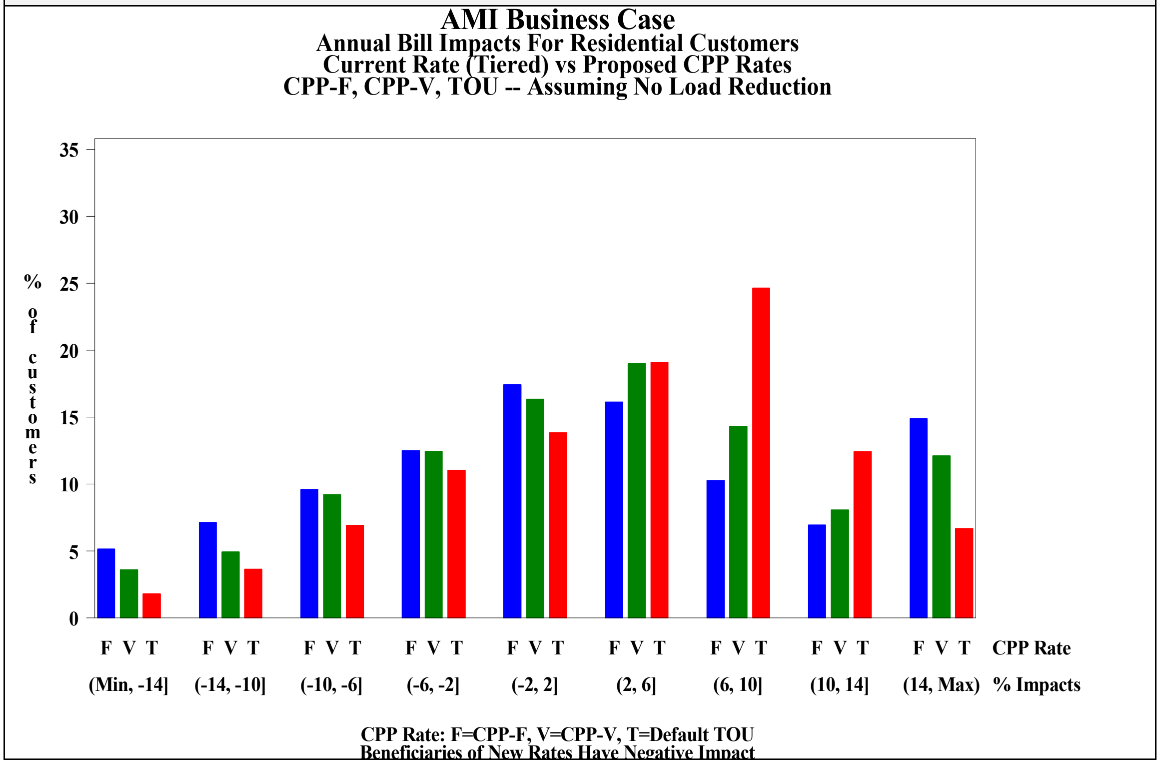


Table 2-18
Residential Bill Impacts - Tiered vs. CPP-F -Percentage Distribution of Accounts by Average Monthly Usage and Percent of Bill Impact

Average Monthly Usage	(Min, -14]	(-14, -10]	(-10, -6]	(-6, -2]	(-2, 2]	(2, 6]	(6, 10]	(10, 14]	(14, Max)	Total
0 - 400 kWh	0.5	1.2	1.9	4.9	10.1	10.9	6.1	3.0	6.3	44.9
401 - 800 kWh	1.6	4.0	5.2	5.4	5.3	3.7	3.2	3.1	7.6	39.1
> 800 kWh	3.1	2.0	2.5	2.1	2.0	1.6	1.0	0.8	1.0	16.1

Note: Positive bill impacts indicate a higher CPP-F bill relative to the tiered OAT.

Table 2-19
Residential Bill Impacts Tiered vs. CPP-F
Percentage Distribution of Accounts by Climate Zone and Percent of Bill Impact

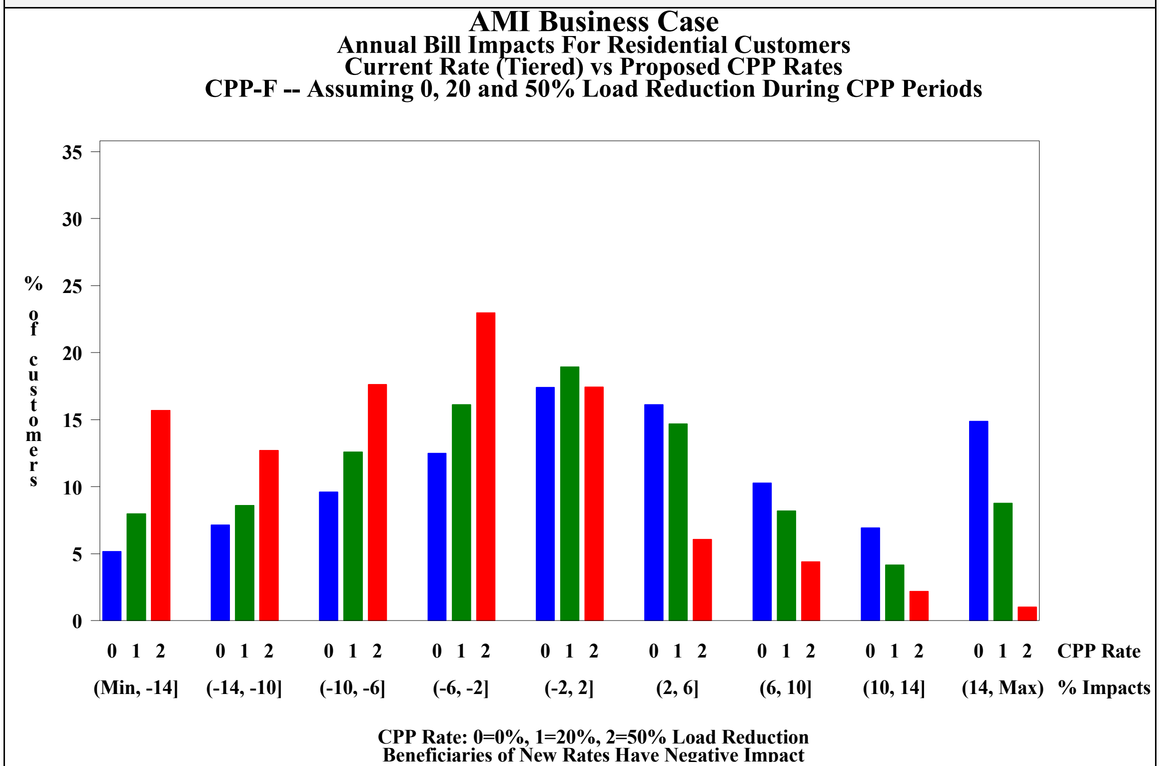
Climate Zone	(Min, -14]	(-14, -10]	(-10, -6]	(-6, -2]	(-2, 2]	(2, 6]	(6, 10]	(10, 14]	(14, Max)	Total
2	3.5	4.7	4.9	6.9	9.1	8.5	4.1	1.4	1.5	44.7
3	1.2	2.2	3.8	4.7	7.1	6.4	5.0	4.8	11.3	46.5
4	0.4	0.2	0.9	0.9	1.2	1.2	1.2	0.7	2.0	8.8
Total	5.2	7.1	9.6	12.5	17.4	16.1	10.3	6.9	14.9	100.0

Note: Positive bill impacts indicate a higher CPP-F bill relative to the tiered OAT.

Overall, the TOU and CPP-F rates shift about six to eight percent of the overall revenue burden from the winter season into the summer season, respectively. This type of revenue/cost shift can be accomplished with the existing metering via seasonal energy charges though the peak demand impact of such a seasonal revenue allocation shift would need to be explored. The cost/benefit associated with this option would prove valuable as incremental cost would be negligible and there would almost surely be some demand response benefits.

Figure 2-4 below displays three annual bill impact distributions (CPP-F non AB1-X compliant versus their tiered OAT rate) for the residential population assuming three different levels of load reduction (0%, 20%, and 50%) for all customers billed on a CPP-F rate. For simplicity, no load shifting was assumed nor were rates re-calibrated to preserve revenue neutrality. Without any load reduction during CPP events, the number of customers experiencing at least a ten percent annual bill increase is above twenty-two percent. The most striking component of the bill impact analysis is that the lowest usage customers whose bills would otherwise be frozen by the provisions of AB1-X would see significant bill increases. At the twenty percent load reduction level, typical of the maximum load reductions seen in the SPP pilot, about thirteen percent of residential customers still see bill increases of more than ten percent while only about sixteen percent of our customers would see an annual bill decrease of at least ten percent.

Figure 2-4
Annual Bill Impacts for Residential Customers – Assuming Load Reductions During CPP-F Periods



The risk associated with such distributions is that if customers save such small amounts while making significant efforts to alter their behavior, they could likely become disillusioned with the program. The cause of this low bill impact despite rather large demand response is that the number of hours designated as CPP periods represents less than one percent of the total hours of energy consumption in the year (seventy-five CPP hours versus 8760 total hours/year). While the CPP rates designed for this application have even a higher ratio to otherwise applicable on-peak rates (at a 6:1 ratio) versus the CPP-Pilot rates, customer bill reductions remain relatively small in spite of significant customer response. It is this type of minimal billing impact despite significant load shifting/reduction is exactly that led to the demise of Puget Sound Electric's system-wide TOU deployment. Despite customer response, low bill reductions to those who responded and bill increases associated with the TOU meter cost (at a relatively modest $1/month) led to overall bill *increases* that caused such customer backlash that Puget Sound Energy cancelled the program after less than two years.[56]

Exit interviews of the SPP customers will prove valuable at the end of the SPP pilot to gauge ongoing interest and cost savings relative to the effort required to achieve those savings. It is only when customers shed fifty percent of their load during the CPP periods (an extremely unlikely case especially for low usage customers) do significant cost reductions occur (though still not in all cases). In general, the most significant discretionary load capable of providing such a large reduction in load is air-conditioning equipment. It is this overlap that makes us believe that focus on the ALC program is the best alternative for providing cost effective price-induced demand response. Figure 2-5 displays similar information using the CPP-V rate design.

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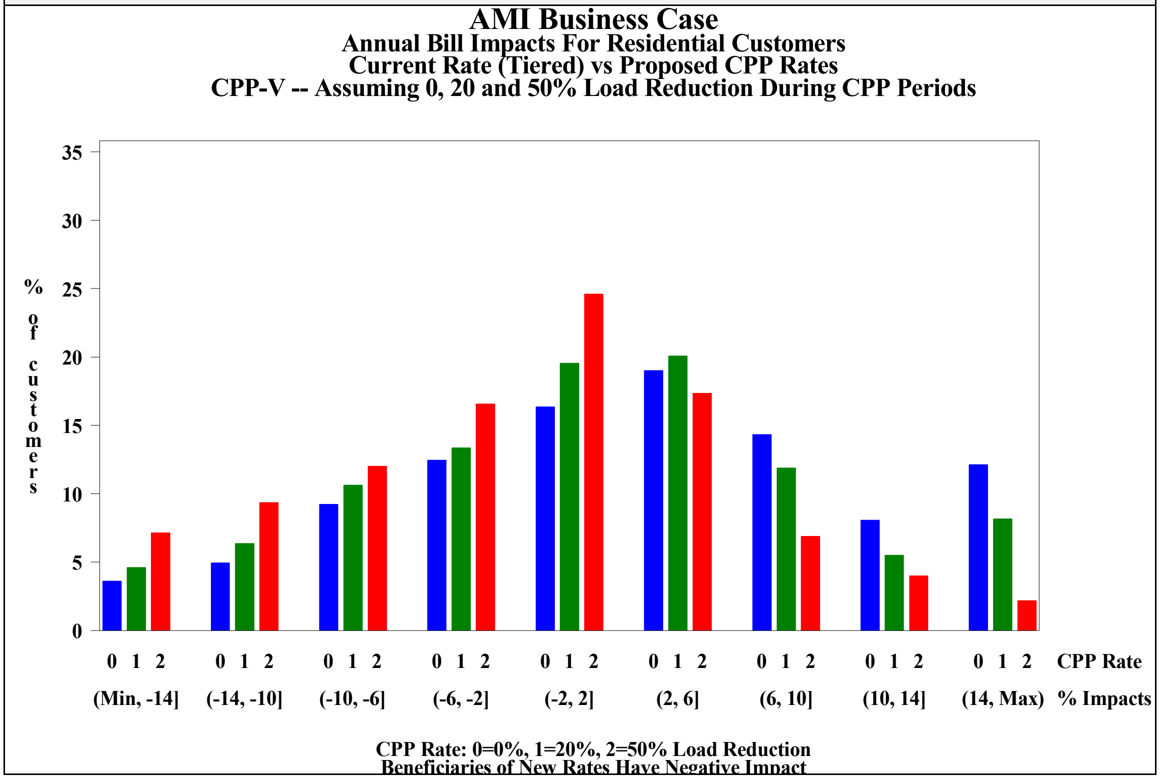
[56] Williamson, Craig, "Primen Perspective: Puget Sound Energy and Residential Time-of-Use Rates – What Happened?," Energy Use Series, Volume 1, Issue 10, December 2002.

Figure 2-5
Annual Bill Impacts For Residential Customers –
Assuming Load Reductions During CPP-V Periods

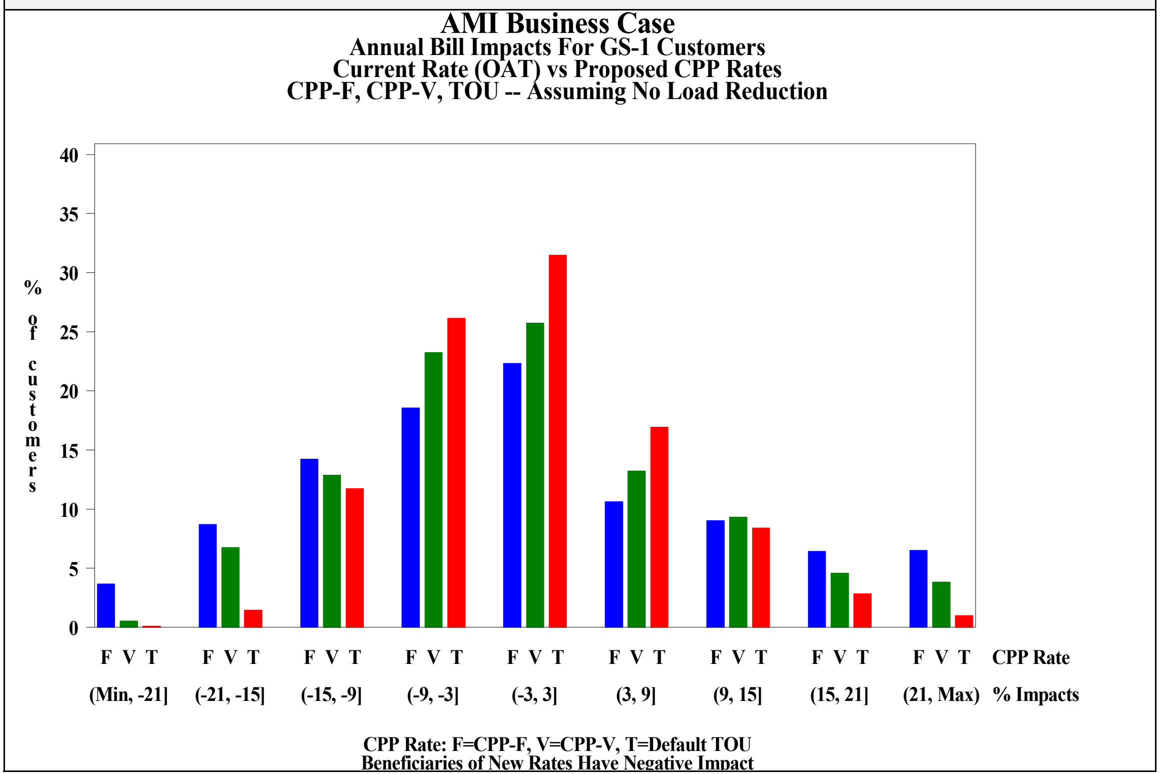


2. <u>Commercial Bill Impacts</u>

As part of the revenue neutrality component in the rate design process, SCE computed average bills for each of the 3,100 and 3,500 customers in its GS-1 and GS-2 load research rate group samples. After applying the relevant sampling weights, rates were scaled to insure that the total bills recovered the same revenue for each customer class. The large load research samples were used instead of the Statewide Pricing Pilot (SPP) sample data to gauge these impacts due to their larger sample sizes and to eliminate any impacts of participation bias.

Figure 2-6 displays bill impact distributions for the small commercial (GS-1) population for the CPP-F, CPP-V, and TOU rate schedules relative to the current GS-1 rate. Again, no load shifting as a result of price response was assumed here. While all three distributions center around zero, under the CPP-F program, about twenty-five percent of GS-1 customers will experience an annual bill increase of at least nine percent, while about twenty percent of the GS-1 population will experience a bill decrease of at least nine percent due to the more precise cost allocation nature of these rates versus a rate with only seasonal energy charges. The CPP-V and TOU bill impacts have narrower dispersions.

Figure 2-6
Annual Bill Impacts for GS-1 Customers –
Assuming No Load Reduction



Figures 2-7 and 2-8 display bill impact distributions (CPP-F and CPP-V versus their OAT) for the GS-1 populations assuming three different levels of load reduction (0%, 20%, and 50%) for all customers during CPP periods. Load reductions associated with businesses are generally less than residential customers, making the twenty percent and fifty percent cases that much more unlikely (except perhaps in such instances where the utility directly controls the customer's load). The GS-1 and GS-2 bill impact distributions display similar results to the residential population.

Figure 2-7
Annual Bill Impacts for GS-1 Customers – Assuming Load Reductions During CPP-F Periods

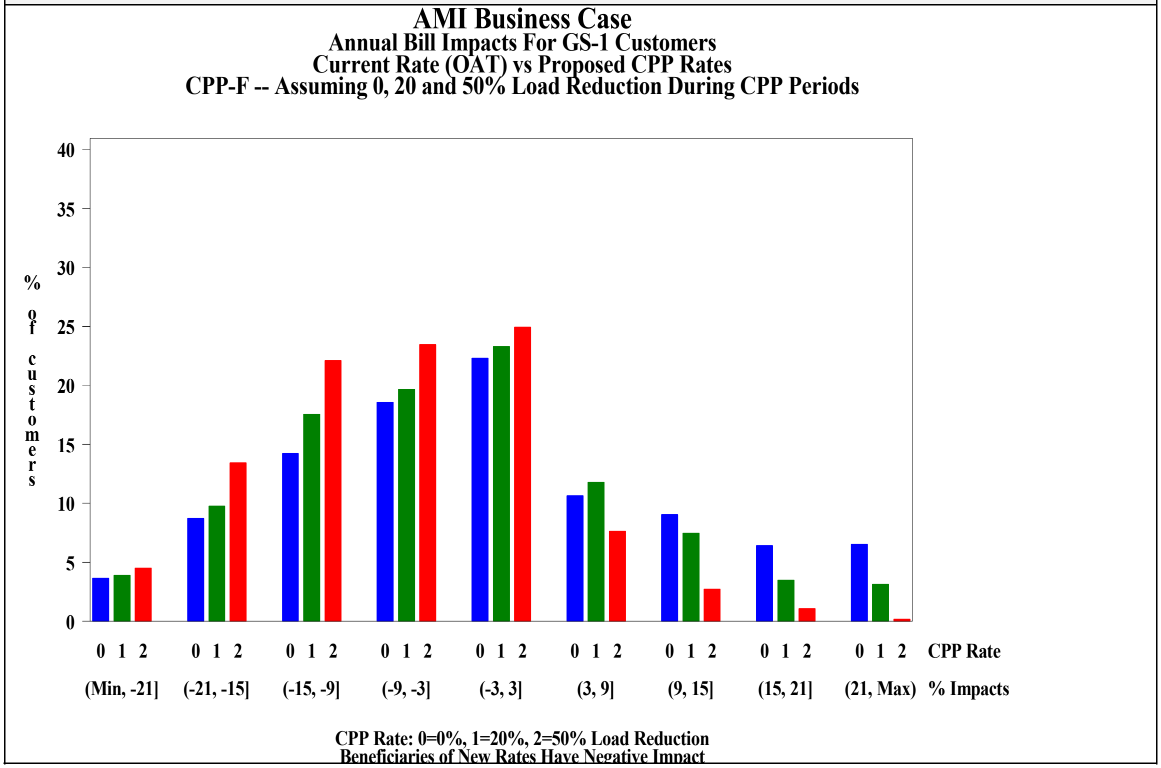


Figure 2-8
Annual Bill Impacts for GS-1 Customers –
Assuming Load Reductions During CPP-V Periods

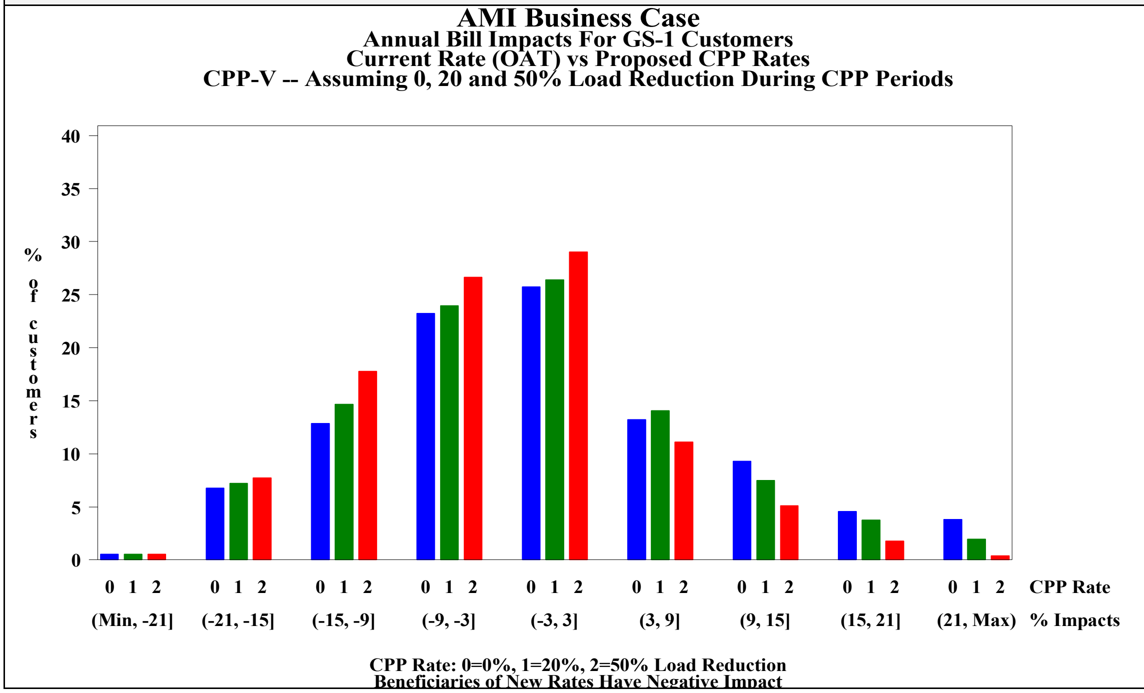


Figure 2-9 displays bill impact distributions for the medium commercial (GS-2) population for the CPP-F, CPP-V, CPP-P and TOU rate schedules relative to the current GS-2 rate. Again, no load shifting as a result of price response was assumed here. Compared to the GS-1 bill impact distributions, the GS-2 distributions are somewhat less dispersed as a significant portion of the rate group's total revenue is recovered via demand charges. For these rates, all demand charges were set to equal the existing GS-2 rate constraining the differences between the rates to energy charges. Figure 2-10 and Figure 2-11 show that the largest bill impacts occur when customers shift fifty percent of their energy consumption out of CPP-F and CPP-V periods. The magnitude of the bill impacts, under the twenty percent reduction scenarios is somewhat subdued as only about eleven percent of these customers realize an annual bill reduction of nine percent or more.

Figure 2-9
Annual Bill Impacts for GS-2 Customers – Assuming No Load Reduction

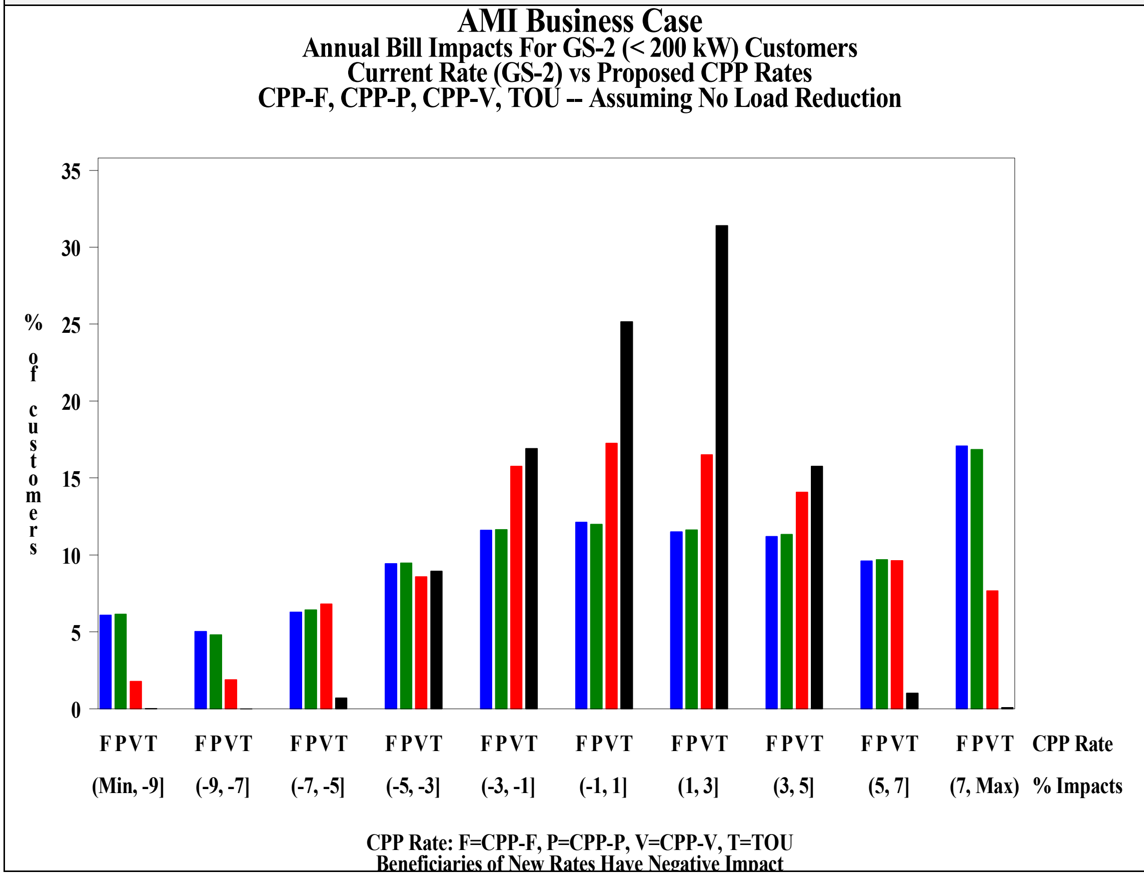


Figure 2-10
Annual Bill Impacts for GS-2 Customers – Assuming Load Reductions During CPP-F Periods

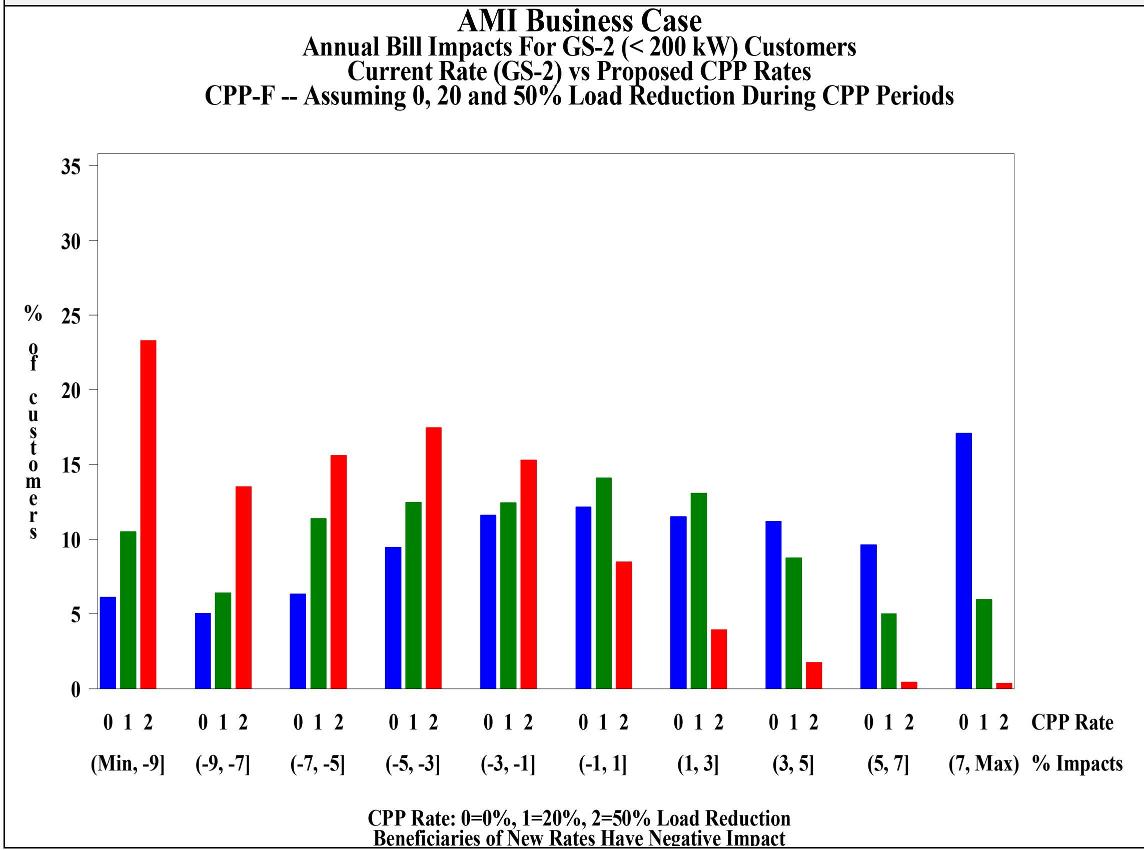
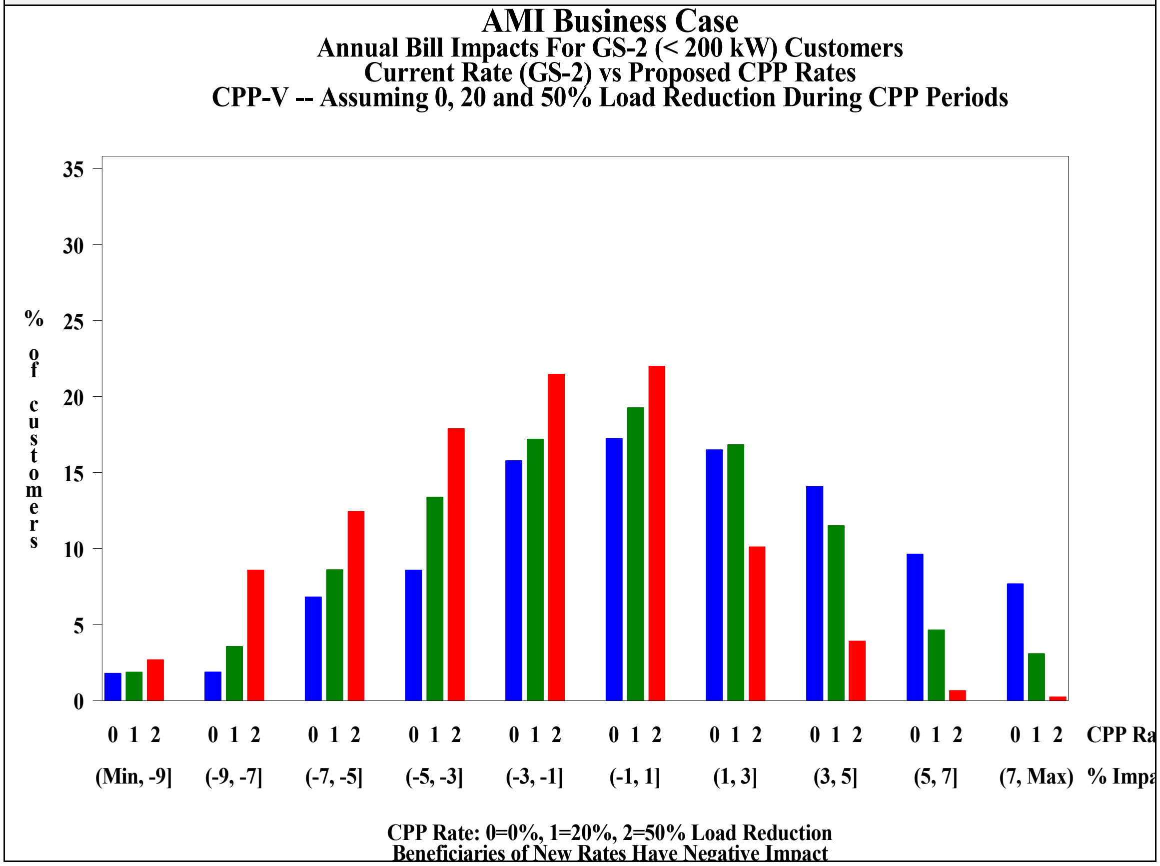


Figure 2-11
Annual Bill Impacts for GS-2 Customers –
Assuming Load Reductions During CPP-V Periods



Proceeding No.: R.02-06-001
Document No.: SCE-3

SOUTHERN CALIFORNIA
EDISON

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(U 338-E)

Advanced Metering Infrastructure Business Case Preliminary Analysis

Volume 3 – Analysis of Full Deployment Business Case Scenarios

Before the
Public Utilities Commission of the State of California

Rosemead, California
October 22, 2004

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PRELIMINARY ANALYSIS OF ADVANCED METERING INFRASTRUCTURE BUSINESS CASE

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I.

INTRODUCTION

The purpose of this volume is to present our detailed preliminary business case analysis as required by the Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure (AMI) issued on July 21, 2004 (Ruling). This volume sets forth our preliminary business case analysis of full deployment of AMI on a scenario-by-scenario basis as identified in Attachment A of the Ruling.

Attachment A of the Ruling identified eight different full deployment scenarios that the utilities are to analyze. Since we believe some of the required assumptions are improbable, especially with regard to customer acceptance of CPP rates, we have provided three additional scenarios with what we believe to be more reasonable assumptions. Recent market research studies showed approximately thirty-five percent of residential customers surveyed, "never give much thought to utilities until the water or power goes out".[1] Given the apparent apathy approximately one-third of our 4 million residential customers have toward their utility services, we feel it will be difficult to implement the necessary behavioral changes many of the scenarios require. Thus, we are presenting detailed preliminary analysis of three additional scenarios with reduced customer participation expectations, for a total of eleven different full deployment business case scenarios. We have chosen the fifty percent participation rate for our alternative analysis scenarios not because we have support for that number either, but because it will provide a reasonable mid-point for purposes of determining the

[1] ARD0075 Residential Segmentation: Southern California Edison Customer segmentation Research, December 2003.

sensitivity of both costs and benefits to varying a critical assumption within the Ruling.

Section II describes the expected impacts to our various business processes, operations and systems resulting from the full deployment scenarios using the AMI technology solution described previously in Volume 2.

Based on the impacts identified in Section II, Section III provides the detailed cost analysis in the Ruling's three major analytical categories (start-up and design; installation; and operations and maintenance) along with the five applicable cost categories[2] and seventy-nine individual cost codes associated with these cost categories. The benefit analysis is also provided in these sections by the four major benefit categories and forty individual benefit codes associated with these benefit categories. Section III also includes a discussion of the risks and uncertainties that we've been able to identify and presents the NPV analysis based on the costs and benefits identified for each scenario.

Section IV sets forth the preliminary revenue requirement impacts for each full deployment scenario based on the detailed cost and benefits information provided in Section III. The preliminary customer impacts we expect for each of the full deployment scenarios are also provided in Section IV. A detailed cost recovery proposal will be part of our final analysis and formal application that will be filed later in this proceeding.

In the process of compiling the preliminary results of this analysis, several errors have been discovered, and are footnoted as they apply throughout this Volume and Volume 4. Some of these errors overstate the costs and some understate costs; thus they tend to offset one another as they relate to the total impact on any given scenario. We expect to correct all identified errors before our

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[2] The Ruling specifies a sixth category for natural gas impacts. These costs are not applicable for SCE's business case analysis and thus, are not included.

final showing in December and we don't expect these corrections will have a material impact on the overall conclusions of this analysis.

II.

OVERVIEW OF FULL DEPLOYMENT BUSINESS CASE

This section describes the impacts of a full deployment case on all of the various operations, processes and information technology systems throughout the company. As required by the Ruling, this section describes the functional capabilities of the advanced meters and supporting network using the RF technology solution described in Volume 2. This section also describes how full deployment would be rolled out, including the schedule of deployment and how we will achieve the customer coverage required by the Ruling. To help facilitate the Commission's understanding of the implications of full deployment, this section describes the full deployment case by its impact on our operations, using the Ruling's five applicable cost categories. The costs and benefits for each scenario of the full deployment case are discussed in Section III, on a scenario-by-scenario basis and quantified using the cost and benefit codes identified in Appendix A of the Ruling.

A. Metering System Installation and Maintenance Category

This section describes the operation, processes and systems that are impacted by full deployment for activities that fall under the Ruling's meter system, installation and maintenance category. Under the full deployment cases, this category involves our meter procurement, supply chain management, testing, installation and associated support activities. In order to gain a better perspective of the impact of full deployment on these activities, this section also describes the number of customers who would receive AMI meters in the full deployment business case and our process for determining how we arrived at that number. This discussion is required by the Ruling.

1. Number of Customers Receiving AMI Meters Under Full AMI Deployment

The Ruling requires that full deployment reach no less than ninety percent of SCE's customer base.[3] For SCE, this means that AMI must be deployed and operational to approximately 4.46 million of the 4.95 million meters throughout our service territory. In order to properly determine the specific coverage capabilities of the communications technology infrastructure discussed in Section III of Volume 2, a comprehensive study would be required in order to identify the specific locations that can be supported cost effectively. For example, the RF path between a specific meter and the data collector can be obstructed by hills or large structures, thus creating a RF "blind-spot" even when the meter is located within the effective range of the network. Without an actual field survey of specific locations, it is not possible to determine which or how many meters will be affected. However, given the short timeframe to conduct the business case analysis, such a study was not performed. Instead, we are providing an estimate of the deployment needed to meet the Commission's objective of reaching ninety percent of the customer base. We estimate that we will need to deploy AMI meters to ninety-seven percent of the existing meters (4.81 million meters) so that ninety percent of the total meters will communicate with the network, as required. We also estimate that approximately three percent of our meter population simply will not be included in the full deployment because it will not be economically feasible (primarily due to remote locations) to do so or the meters are not owned by SCE (*e.g.*, DA customer-owned meters). For the ninety-seven percent of the meters that are deployed, we assume that once the RF networks are operational, approximately seven percent of the deployed meters will fall within RF "blind spots" and thus will

[3] Ruling, Attachment A., p. 6.

not possess remote read capability due to the unique positioning of the meter itself and/or its physical surroundings. The seven percent estimate is based on our experience with the existing RF infrastructure and a review of the meters that will likely fall outside of the planned coverage area because of the unique geographical terrain and customer population densities.

a) Roll-Out Plans for Full Deployment

In order to fully deploy 4.81 million AMI meters in a five-year period as contemplated in the Ruling, we are required to pursue an extraordinarily aggressive deployment schedule throughout our service territory. Our service territory is comprised of twenty-four service centers servicing the densely populated metropolitan areas of our service territory and ten service centers serving the expansive yet sparsely populated rural areas of our service territory. Approximately ninety-eight percent of the 4.81 million meters are associated with the service centers serving the metropolitan areas. SCE decided to stage the startup of deployment to the 24 service centers, as depicted in Table 3-1.

Table 3-1 Full Deployment Start Date by Service Center			
Service Center	2nd Quarter - 2006	3rd Quarter - 2006	4th Quarter - 2006
Covina	X		
Long Beach	X		
San Jacinto Valley	X		
Compton	X		
Ventura	X		
San Joaquin	X		
Foothill		X	
Whittier		X	
Santa Ana		X	
Huntington Beach		X	
Ontario		X	
South Bay		X	
Thousand Oaks		X	
Antelope Valley		X	
Fullerton			X
Saddleback			X
Redlands			X
Palm Springs			X
Montebello			X
Monrovia			X
Santa Monica			X
Santa Barbara			X
Valencia			X
Victorville			X

The full deployment process will begin in the second quarter of 2006 and will start with the six largest service centers in terms of number of meters eligible for deployment. In the third quarter of 2006, the deployment efforts will be expanded to eight additional service centers. In the fourth quarter of 2006, the efforts will be expanded to the remaining ten service centers.

Our deployment strategy took into consideration meter densities, as well as concentrations of already deployed AMR meters. As discussed in Section II of Volume 2, we have already deployed AMR throughout our service territory, concentrated in areas where it was most cost-effective to do so. The vast majority of these meters are read through a van-based process under contract with a third party provider. To meet the metering requirements of the Ruling, we expect these AMR meters will have to be replaced with the AMI meters and the meter reading contract will have to be terminated prematurely. In order to mitigate the effects of full deployment on this investment in AMR, we took into consideration the concentration of AMR meters associated with each service center. We will begin replacing the AMR meters as late in the five-year deployment as possible in order to mitigate costs associated with stranding this investment. We expect to complete the deployment in all of the twenty-four service center areas by the end of 2010, as directed by the Ruling.

For the ten service centers that serve the rural areas of our service territory, full deployment will begin in the second quarter of 2006 and will be completed by the end of 2010. As discussed in Section III, in order to mitigate costs with full deployment in the rural areas, we expect to have one installer in each service center beginning in the second quarter of 2006.

b) Annual Deployment Volumes

As required by the Ruling, Table 3-2 shows the annual volumes of AMI meters by customer class under the full deployment case.

Table 3-2
Annual Deployment Volumes by Customer Class

Year	Customer Class: Residential and Small Commercial	Customer Class: Commercial and Agricultural (20 kW - 200 kW)		TOTALS BY YEAR
2006	520,407	53,648		574,055
2007	1,075,421	69,543		1,144,964
2008	1,075,421	73,517		1,148,938
2009	1,075,421	77,491		1,152,912
2010	706,871	81,465		788,336
Total				4,809,205

2. Description of Meter System Installation and Maintenance Activities Impacted by Full Deployment

The meter system installation and maintenance category involves all of our activities associated with meter procurement, supply chain management, testing, installation and other support. The impacts on these activities as a result of full deployment are described in detail in the following subsections.

a) Meter Procurement

Based upon the various types of meter sites in our service territory, we will procure five different types of meters for AMI deployment. In addition to procuring the AMI meters, we will modify some of our inventory activities to accommodate full deployment. First, under a new process, each newly procured meter will be equipped with a Radio Frequency Identification (RFID) tag. This allows us to automate the procurement and supply chain processes from the initial receipt of the meter from the vendor all the way through the dissemination of the meter to field personnel for installation. In addition, we will need to procure meter lock rings that will be installed on each meter at the time of deployment.

Finally, we will also need to procure external antennas for a portion of meters requiring such an installation at the time of deployment.

b) Supply Chain Management

Currently SCE's Procurement and Material Management (PAMM) group receives, stocks, and distributes approximately 120,000 meters per year. Under full deployment, PAMM will increase distribution to a peak of approximately 1.2 million meters a year. In addition, it is estimated that there will be approximately 1.4 million additional meters that will need to be processed from 2006 to 2021 due to meter replacements that result from failures in the field. The estimated number of meter failures by year end under full deployment is shown in Table 3-3 below.

Table 3-3
Estimated Meter Failures by Year

Year	Estimated Meter Failures
2006	20,977
2007	168,206
2008	143,301
2009	120,290
2010	95,774
2011	95,609
2012	95,413
2013	95,186
2014	94,927
2015	94,643
2016	94,332
2017	93,997
2018	93,637
2019	93,253
2020	92,848

Given our prior experience with meter vendor reliability and the massive scale of full deployment, we propose to maintain approximately three months worth of inventory in our distribution facility. In order to meet the full deployment schedule described earlier in this Section, the distribution facility will need to begin stocking meters by the fourth quarter of 2005. This will allow PAMM to distribute 100,000 meters per month to various SCE locations beginning in January 2006 to support deployment and installation beginning April 2006.

Under full deployment, PAMM will deliver meters to the service centers one to two times a week so that materials are received on a just-in-time basis and thereby avoiding additional secure storage requirements. Additional personnel will be required in the service centers to process the meters when they are received. The meters are then stored in a secure area until the point they are scheduled for distribution. Due to the short-term nature of this project, we propose to use a Temporary Project Accountant position to process the meters at the service centers.[4] The Temporary Project Accountants will also be responsible for the distribution of the meters to the installers according to the installation schedule that will be developed. Once the installers replace the existing meter with the new AMI meter, the returned meters will be processed at the various service centers for salvage purposes.

c) Meter Testing

For residential meters, we plan to test 100 percent of the first two shipments of meters for quality assurance purposes. After that point, we will use a statistically significant sampling method to test the meters. For commercial meters, we plan to test 100 percent of the first 10,000 commercial meters for quality assurance purposes. Similar to the residential meter testing, we plan to use a statistically significant sampling method for testing the remainder of these meters.

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[4] Use of this temporary position assumes that we will be able to secure IBEW approval for such a position.

Meter testing will be conducted at our existing meter shop facility that will need to be reconfigured to handle the increased volume of work. Although full deployment of AMI will reduce some of the existing meter test work, the meter testing workload will increase overall because of the scale and pace of full deployment. As such, additional personnel will be required to handle this increased testing.

d) Meter Installation

(1) Residential and small commercial (less than 20 kW)

As discussed in detail in Section III of Volume 2, the communications network and information technology applications will not be operational until June 2007. Thus, we expect to continue our current meter reading and field service practices for all meters, even those that receive an AMI meter before June 2007.[5] We analyzed various methods to handle the AMI installations and continue our existing field work. Because full deployment is short-term in nature, we determined that it would be more cost effective to hire temporary personnel rather than full-time personnel so as to avoid incurring severance costs for full time resources when the deployment concludes[6]. The use of temporary resources depends on the assumption that we will receive IBEW concurrence to reactivate the "Project Temporary Meter Reader" job classification and approve the creation of a "Project Temporary Installer" job classification[7]. Another full deployment impact in this area is the use of mandatory overtime. Given the cost

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5 As described above in Section III of Volume 2, in addition to manually-read meters, we currently have over 350,000 AMR meters that are being read via van-based automated meter reading. In addition, we currently collect interval data on a daily basis from more than 12,000 commercial customers with RTEMs.

6 Severance costs are estimated at $58,530 per meter reader.

7 IBEW approved the use of the project temporary meter reader job classification for the 2000 AMR deployment.

and performance trade-offs of utilizing overtime as an alternative to hiring incremental personnel, we expect to utilize both of these options.

(2) Complex Meter Installations

In our service territory, we have approximately 356,000 meters that are considered complex and are therefore handled by our Meter Technicians who have specialty training. These complex meters are associated with Rate Schedule GS-2 and accounts with monthly demands above 20 kW. These also include 240v three-phase accounts and residential accounts with current transformers and potential transformers. In order to support the aggressive full deployment schedule, we will rely on both full-time and contract resources, as well as the use of mandatory overtime, to install these complex meter configurations.

e) Support Related Costs

In order to support the AMI deployment, our field personnel will need to attend various training classes. As new meter readers are hired to backfill for those who have taken Field Service Representative or Project Temporary Installer positions, they will need to attend new hire meter reading training. As existing Meter Readers transition to Field Service Representative positions to backfill for those who have taken Project Temporary Installer positions, they will need to take classes on handling billing inquiries and using various customer service systems. Project Temporary Installers, who will handle the meter installations for the residential and less than 20 kW commercial accounts, will need to undergo a training program that covers the Meter Installation Procedures and Practices manual as well as training on how to use our meter tracking systems.

B. Communications Infrastructure

As detailed in Section III of Volume 2, the radio frequency communications system selected for full deployment will be comprised of collectors, packet routers, and Metricom Communication Controller (MCC) take-out points. Our AMI technology solution leverages our already-existing network and expands from there. New collectors will be mounted primarily in the power space of a utility pole or streetlight and will communicate with the radios in the residential and less than 20 kW meters to transmit meter data throughout the network to the MCC take-out points. In the RFI response, the vendor indicated that SCE would need to install 8,000 collectors throughout the service territory in order to achieve the ninety percent coverage requirement. Based upon our experience with the RF infrastructure currently operating within our service territory, we believe it is prudent to install an additional twenty percent, or 1,600 collectors if necessary to achieve the ninety percent coverage. As such, our business case analysis assumes the installation of 9,600 collectors.

The meter technology for greater than 20 kW customers includes the use of a "radio under the meter cover" technology that will provide a RF "mesh-type" network of an additional 168,000 radios to the overall AMI communications network. Given the large number of meters in full deployment, we anticipate heavy congestion on the communications network, particularly for those locations in close proximity to the MCC take-out points. The installation of a packet router will help ease this congestion and ensure that the data is transmitted to the SCE network in a timely manner so that it is available for bill calculation. We have assumed the installation of ninety-six packet routers.

Installation of the MCC take-out points is required to collect the meter data and transmit it to our computing network where it can then be accessed for billing purposes. Under full deployment, we expect to supplement the 100 MCC take-out points we have in place today with 181 additional MCC take-out points.

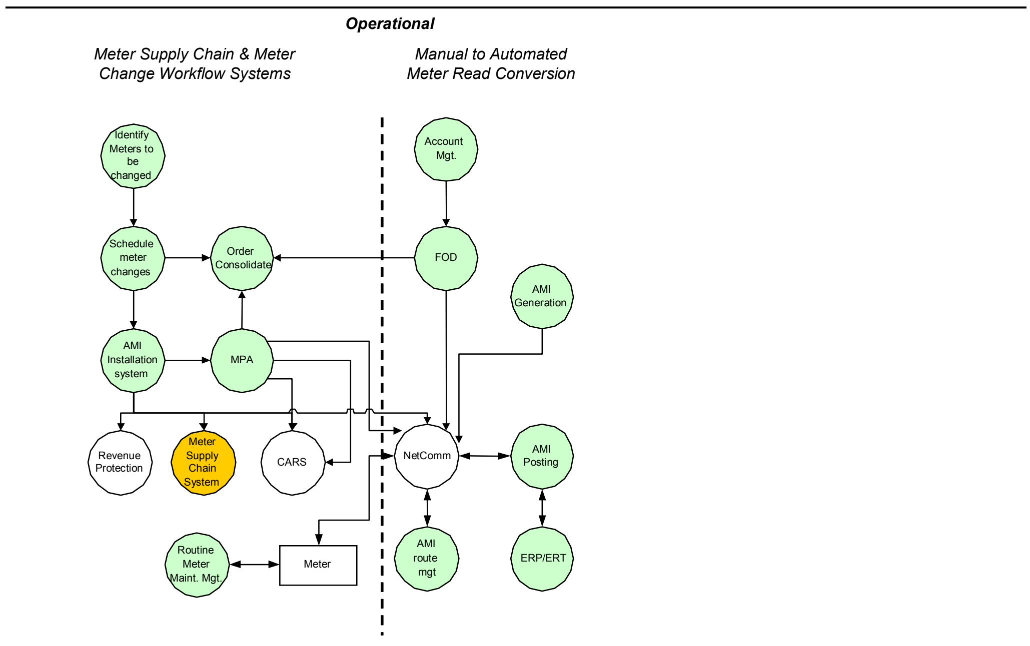
C. Information Technology Infrastructure

The Information Technology (IT) and application cost category captures the costs associated with applications and computer services necessary to support AMI. These activities are described in more detail in the sections that follow.

1. Applications

Under full deployment, we will need to enhance certain existing IT systems and develop new ones. Figure 3-1 illustrates the conceptual system architecture of the IT systems that will be required for full deployment.

Figure 3-1
Full Deployment IT Systems Architecture



The IT systems that need to be developed or enhanced to support full deployment are in the operational areas of meter supply chain management, meter change workflow, and meter read conversion. The following subsections briefly describe each of these operational areas and the systems that will be developed or the enhancements that will be made to existing systems.

a) <u>Meter Supply Chain Management</u>

We will need to make changes to the Meter Supply Chain (MSC) System so that the following procurement processes can be automated under full deployment:

- Order and delivery tracking from the meter vendor

- Verifying receipt of the meters and reconciliation with the order
- Logging the meter as an SCE asset
- Testing of new meters
- Distribution of meters from the warehouse to Service Centers for installation

Each pallet of meters received from the vendor will be equipped with RFID tags. Upon receipt of the meters in SCE's warehouse, the RFID tags on the meters and pallets will be "read" into the system to verify and reconcile the order. RFID tags on individual meters will transmit unique asset identifications into the MSC system to track meters throughout the entire deployment workflow. The MSC system will register meters as SCE assets and manage the distribution of the meters to our service centers for installation.

The MSC system will also be capable of interfacing with several related systems. For example, the MSC system will interface with the AMI Installation system, described later in this section, to pass meter delivery information automatically to the service centers. Further, MSC system will interface with SCE's general ledger system to record new and retired asset information as meters are replaced and installed during full deployment.

b) <u>Meter Change Workflow Systems</u>

As shown above in Figure 3-1, a number of new IT systems will be needed to handle the meter change workflow in the areas of:

- New Meter Identification
- Meter Changes Order Scheduling
- AMI Installation
- Meter Order Consolidation

- Meter Process Automation

First, a new system will be necessary to identify the meters that that will require a change to the new AMI metering. This application will have the functionality to identify sites by location where the AMI meters need to be installed. The application will interface with the MSC system to identify the exact meters to be installed at a particular site.

In addition, full deployment will require development of a new system to track and schedule meter change orders. Our current Meter Process Automation (MPA) system handles meter change requests at an individual meter site level and could not handle the significant volume of meters involved in a full deployment. Therefore, a new system is required to handle the significant volume of meter changes associated with full deployment. The new Scheduling Meter Change system (SMC) will need to interface with the new AMI Route Management system that verifies all meters for a route are, in fact, ready for AMI integration. The SMC system also automates the switching to the AMI network. It will need to interface with the current Customer Data Acquisition Management (CDAM) system which maintains the route information. Building this interface will ensure that the SMC system efficiently schedules meter change orders. The new SMC system will also be used to track planning activities, (*e.g.*, city or field inspections), related to AMI meter installation. This system will have the ability to issue and cancel orders, as well as schedule appointments or reprioritize orders as field conditions warrant.

Full deployment will also require a new system to handle the collection of necessary meter information to properly route the meter installation request to the field personnel installing the AMI meter. This new AMI Installation (AMI-I) system will provide the field personnel with the route information necessary to locate the meters that will be changed. As meter removals and installations are completed by the field personnel, the AMI-I system will process completion information, including global positioning system (GPS) data, and deliver it to the Meter Inventory system for further processing.

The AMI-I system will also interface with the SMC system to reschedule orders that were not completed. This system will also generate various exception situations that will require special processing. An order download/upload process will be built to perform interface functions between the host mainframe system and the Field Tool system. The users of the Field Tool will have the capability to view orders and input completion information. The Field Tool will also have the flexibility to allow users to cancel or defer orders, if appropriate.

As a result of full deployment, a new system is required to interface with the existing MPA system which currently schedules, tracks, and posts data on meter orders. The Order Consolidation (OC) system will be developed to examine various meter orders for the same installed service account to consolidate them and maximize operational efficiency.

To accommodate full deployment, we expect to make enhancements to the existing MPA system. Enhancements are necessary because the current MPA system is not capable of managing the meter volumes expected in full deployment. An interface to the new AMI-I system will be required to provide a link to the MPA system. In addition, enhancements are required so that the MPA system can store GPS data that is being returned from the field to facilitate meter location tracking.

c) Meter Read Conversion

As shown in Figure 3-1, under full deployment, a number of new systems need to be developed to handle the meter read conversion. Additionally, enhancements to existing meter-related systems are required.

As a result of full deployment, we expect that enhancements to the current Account Management (AM) system will be required. The AM system is responsible for the various administration and maintenance activities associated with each customer's account. For full deployment, user functions will need to be modified to handle interval data usage. As an example, the Bill Correction function will need to be changed so that users have the ability to input interval data usage in situations where the data is not available for certain periods of time. Another example of a user function requiring modification involves changing the data validations and prorating algorithms to handle interval data usage.

We also expect enhancements will be needed to the current Field Order Dispatch (FOD) system to accommodate full deployment. The FOD system is currently responsible for the management of field visits related to metering and communications incidents that may include error detection, failures and replacements. New enhancements will need to be developed to route field events from the FOD system to the AMI communications network support group and meter support groups.

Full deployment will also require the development of a new system to monitor the status of accounts on each of the meter reading routes to determine when all of the installed AMI meters on a particular route are communicating with the network. Once this new AMI Route Management system has validated that all newly installed AMI meters on a route are successfully communicating with the network, the meter reading route can then be switched to an AMI route.

We expect full deployment to require a new system to generate requests for meter reads from the communications network. An AMI Generation system will be developed to identify and generate accounts that are scheduled to be billed on any particular day. Based upon this data, the AMI Generation system will create requests for the network to gather meter data from these accounts so that bills can be prepared.

Under full deployment, a new system is needed to collect meter read information from the communications network; validate the data; and post the data in the Customer Service System (CSS) meter reading tables. If the data fails certain validations, the new AMI Posting system will generate a new exception to be included in the CSS exception table.

We anticipate that full deployment will require enhancements to the existing Exception Reporting and Routing (ERR) system, which is responsible for reporting, routing, and handling various exceptions. Enhancements will be made to the ERR system so that non-communicating equipment (meters, collectors, etc.) will be reported to the ERR system from the network through an electronic file. In addition, enhancements for the ERR system will be developed to address new exceptions created by AMI processes. If exceptions cannot be resolved automatically by the ERR system, they will be routed to a bookkeeper for resolution.

Each of the new or enhanced systems represented in Figure 3-1 require computing services infrastructure to support the software handling the full deployment AMI data. Computing Services includes the actual procurement and installation of the necessary infrastructure. Computing Services infrastructure and hardware fall into the following broad areas:

- Additional servers
- Additional processors to increase MIPS on the mainframe
- Additional processors to increase processing capacity on Reduced Instruction Set Computer (RISC) and Wintel systems
- RFID tag reading equipment

- Additional Laptop and Desktop computers
- Additional Storage (DASD)
- Incremental personnel to manage installation of additional infrastructure
- Additional operating system and database licenses
- Computer network upgrades

D. Customer Service Systems Category

This section describes the customer service operations, processes and systems that are impacted by full deployment of AMI. These changes are needed to provide an adequate level of customer services essential to assuring efficient installation and operations of the full deployment of the AMI infrastructure. Specifically, the customer services discussed in this section include Billing, Call Center, Meter Order Processing, and Customer Communications (Marketing) activities. This section will not include meter reading and field services activities, because these functions are essential to the Meter System Installation and Maintenance costs discussed above.

1. Description of Billing Activities Impacted by Full Deployment

SCE's Billing Organization currently processes and delivers over fifty-six million customer billing statements each year. For the most part, this process is automated and only a small percentage of the total bills produced require manual intervention. Historically, the two situations having the largest impact on the manual billing processes are meter changes and rate structure changes, both of which play a significant role in our AMI full deployment scenarios. Under a full deployment of AMI, we will need to supplement the current billing system that depends primarily on manual reads in the field to a system that can generate a bill based on AMI data transmitted through the network communications. Billing Operations will also be impacted due to the incremental change out of an additional

1.4 million meters throughout the fifteen-year analysis period, due to the anticipated AMI meter/communication failures.

Under the "operational-only", full deployment scenario discussed below in Section III, we assume that we will read the vast majority of meters remotely only once per month and that there is no need for interval data beyond that which is being collected today. Thus, our processes associated with aggregating, validating, and processing interval data are not impacted in the Operational-Only scenario. As we discuss later in this volume, the processing of interval data has a significant impact on billing costs; this will be particularly evident in the Demand Response scenarios discussed below in Section III, where the majority of accounts will require interval data processing in order to determine consumption and demand readings by time period and/or during critical peak periods. The processing of interval usage data is vastly more complex than simple monthly meter reads and requires an additional layer of validations and the resultant exception processing in order to assure the integrity of each fifteen-minute or hourly read.

At the outset of the operational-only full deployment case, we expect the need for start-up costs associated with the specification of security systems, the development of data retrieval strategies, network planning, and the meter RFP proposal specifications. The largest full deployment impact on the Billing Organization operations and processes occurs during the installation phase resulting from the mass exception processing that is expected to occur as meters are changed out. A small percentage of the changed meters will result in billing related problems (exceptions) requiring manual processing to assure timely and accurate billing. Though small in terms of percentage of the total, the initial change-out of nearly five million meters will result in a significant increase in the number of billing exceptions being processed.

A major contributor to the increased exception processing is the anticipated failure rate of AMI meters in the initial stages of full deployment. When a meter fails in the middle of a billing period, a determination must be made as to how the affected bill (and subsequent bills) will be processed. This process becomes considerably more complex when the affected account depends on the accuracy of interval consumption data. Depending on the nature of the meter failure, a judgment call is often required with regard to estimating consumption. This sometimes involves contacting the customer in order to assure a fair and equitable resolution. A similar process is followed when rate related billing exceptions occur.

We estimate that fifty percent of all meter failures will require exception processing within the Billing Organization. Meter failures are expected to peak at 168,000 in 2007, and drop to a level of 96,000 by 2010. We expect, however, that beyond the initial installation phase, meter failures will continue at a steady state rate of approximately two percent through their useful service life.

Another contributing factor to billing installation impacts is related to the development of new validation routines to replace the validations that currently take place in the field as meters are being read manually. Reading meters remotely adds a whole new layer of data quality concerns, not only attributable to new meter technology, but to the likelihood of communication system failures which will inevitably occur. We know this from experience, not only with the recent implementation of RTEM, but from our earlier experience in implementing 350,000 van-based AMR meters.

Overall, under full deployment, we expect a slight improvement in metering accuracy. We also expect higher meter failure rates and will experience the loss of field validations.

2. **<u>Description of Call Center Activities Impacted by Full Deployment</u>**

Our Call Center receives and handles over 11 million calls per year. Full deployment of AMI is expected to result in call volume increases ranging from a low of 50,000 calls per year for the operational only scenario to a high of 1.6 million calls per year for certain Demand Response scenarios. The majority of the anticipated call volume increases results from customers calling to inquire about the new time-differentiated rate in the Demand Response full deployment scenarios. Our estimate includes the number of customers who will opt-out, in addition to a number of customers who will call to inquire about opting out, but choose to stay on the new rate. In determining the impacts to the Call Center due to full deployment opt-out Demand Response, we estimated that seventy percent of the customers that call to inquire about opting-out would actually opt-out. This estimate is based on our assumption that most customers who call to opt-out will have already made up their mind, however, with proper training of Call Center personnel, we feel we should be able to convince thirty percent of such callers to stick with the program.

We expect that as AMI is deployed and operational, call volume reductions will result from more accurate billing. Billing inquiries today are received for several reasons, one of which is an inaccurate meter read. Based on analysis of 2003 data, 22,791 calls were a result of meter reading errors. We used this number as a percentage of all calls to determine the percent of calls in subsequent years that would be projected as meter read error calls. For the business case, we assumed that 100 percent of these calls would be avoided with automated meter reads. Ultimately, we expect call volume will be reduced by approximately 24,000 calls per year for most scenarios.

E. Management and Miscellaneous Other

This section describes the overall Project Management and miscellaneous "other" costs not previously identified. Other costs include centralized training costs, personnel recruiting costs, employee communications, and miscellaneous start-up costs. For the most part, these costs fall into the Ruling's "start-up" and "installation" categories. The Billing Organization has identified some on-going O&M costs that are expected to continue through the duration of the analysis period.

1. Project Management

For the full deployment scenarios, a project management team consisting of three middle management and two staff support personnel will oversee the five and one-half year installation phase of the project. For the partial deployment scenarios, a similar size project management organization is anticipated, but only for the two and one-half year installation phase. In addition, each of the major operating departments has estimated some project management costs to support the core project management team. We have also determined that in order to meet the deployment schedule proposed in the Ruling, with deployment starting in 2006 and full deployment by 2011, there will likely be project planning tasks that should occur in 2005. However, since the Ruling directed the business cases to start in 2006, the 2005 costs are not included in this filing.

2. Training Costs

Training costs would be incurred within each of the major operating organizations as well as at the corporate level within our centralized Job Skills Training (JST) Organization. Incremental training costs will be incurred not only for specialized instruction related to AMI metering activities and new rate options, but a significant part of the increased training cost will be more generalized, new-employee training. Our JST training includes the cost for development of the curriculum, preparation of the training materials and paying the instructors. JST training is primarily for new employees in the Meter Reading, Call Center and Billing Organizations that will be needed to meet the added workload during the installation phase of AMI. These costs do not include paying the employees themselves for the "seat-time" spent in training sessions. Seat-time costs are included in the cost estimates for each individual operating organization.

3. Customer Communications

Under the "operational-only" scenarios, we expect only a minimum level of direct customer communications costs beyond what we currently experience. If we are required to notify customers of planned meter changes, we expect to comply through a regular monthly bill insert or bill message. Any mass media or other outbound communications that the Commission may feel is needed for purposes of public notification under the operational-only scenario would add incrementally to our estimated costs.

The costs associated with the addition of Demand Response options under the full deployment scenario will differ based on scenario, but the basic structure and approach to the media and information delivery campaign will be similar. The strategic approach of the campaign is to utilize an integrated mix of media designed to affect a long-term cultural and behavioral change. The campaign must be multi-year in order to positively affect long-term change. There are three tenants of the campaign: 1) raise awareness and educate customers about the program and its benefits as well as the behavioral changes required to comply with each specific Demand Response option, 2) develop and implement a strong and comprehensive acquisition effort to recruit customers and meet participation rate expectations, 3) develop and implement a vigorous retention campaign to maintain the customer base over time. The media mix includes:

- Mass Media: Television, radio, and print for education and awareness;
- Targeted/Ethnic Media: Local print, cable television, and strategic partnerships (ethnic business chamber promotion) including the use of in-language media for education and awareness;
- Direct Communications: Bill inserts, direct mail, e-mail notification, voice mail notification, newsletters, face-to-face communication through the account management function for acquisition and retention; and
- “CPP Day” Notification: Use of phone banks, radio, public service announcements, and press releases/press relations to notify customers of CPP Demand Response events.

Each scenario includes a basic level of communication and outreach that is designed to reach 100 percent of our customers, and saturate the customer base with broad based educational campaign as well as specifics on how customers can respond to time-differentiated rates. In addition to the messages contained in the campaign, each full deployment Demand Response scenario will require extensive research to understand consumer attitudes and to adapt messaging appropriately for all geographic and ethnic groups prior to the delivery of the campaign.

The campaign will differ significantly from other SCE campaigns previously undertaken, which are designed to create customer awareness and promote programs on a short term basis. This campaign will create customer awareness and education about behavioral changes required to comply with the chosen Demand Response option, with long-term behavioral and cultural change being essential to the program's success. One of the two main objectives of the campaign is to condition customers to understand why Demand Response requires a behavioral change and move them to change their behavior. Through education, we expect to achieve customers' understanding of their energy usage and the impacts time-differentiated pricing options have on overall costs. This will be achieved through the customer-specific education portions of the campaign. The other main objective of the campaign is to recruit and retain customers on these Demand Response rate programs over time. This will be accomplished through the customer-specific acquisition and retention portions of the campaign.

The cost of the campaign is affected by our location and the customer base we serve. The greater Los Angeles area is the second largest and highest cost media market in the country, and is also very diverse both linguistically and culturally.[8] As such, messages must be created and delivered using languages other than English. Additionally, thirty-five percent of our customer base has demonstrated their lack of interest in electricity issues other than when their power goes out.[9] Customer communications must break through this demonstrated low level of interest and be accomplished through a variety of linguistically and culturally appropriate approaches to properly address the various Asian, Spanish, and African-American cultures and dialects as well as the general population.

Our forecasted average yearly media and advertising costs related to customer communications and education for the Demand Response scenarios are

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[8] 2003 – 2004 Nielson Universe Estimates, DMA Ranking and Advertising Age Magazine, July 24, 2000

[9] ARD0075 Residential Segmentation: Southern California Edison Customer segmentation Research, December 2003.

close in comparison to media and advertising costs for other utilities such as telecoms in the Los Angeles Designated Market Area.[10]

4. Management and Other Costs

This cost category includes other areas where some miscellaneous costs have been identified such as: overseeing the vendor request for proposals (RFP) process, contracts supervision, employee communications costs, personnel recruiting, and employee training and communications relating to customers' access to their own energy usage data. Other management overhead costs that span across two or more functional cost categories, such as project management and the administration of job skills training are also included in this cost category.

[10] 2004, Nielson Media Research

III.

FULL AMI DEPLOYMENT BUSINESS CASE ANALYSIS

This section provides our full deployment preliminary business case analysis. This analysis includes the eight separate full deployment scenarios required by the Ruling, in addition to three full deployment scenarios which we feel better reflect realistic customer participation assumptions for certain demand response and reliability scenarios. Table 3-4 below identifies the full deployment scenarios for which we are providing preliminary analysis.

Table 3-4
Listing of Full Deployment Scenarios

Scenario No.	Description
1	Full: Operational Only (SCE Implemented)
2	Full: Operational Only (Outsourced)
3	Full: Operational + DR (TOU Default with Opt-out)
4	Full: Operational + DR (CPP-F/V Default with Opt-out)
5	Full: Operational + DR (OAT Default with Opt-in to CPP Pure)
6	Full: Operational + DR (OAT Default with Opt-in to CPP-F/V)
7	Full: Operational + DR + Reliability (CPP-F/V Default with Opt-out)
8	Full: Operational + DR + Reliability (OAT Default with Opt-in to CPP Pure)
9	SCE Analysis: Full: Operational + DR (TOU Default with Opt-out)
10	SCE Analysis: Full: Operational + DR (CPP-F/V Default with Opt-out)
11	SCE Analysis: Full: Operational + DR + Reliability (CPP-F/V Default w/ Opt-out)

The following subsections describe the costs and benefits we expect will result from implementing each respective scenario. These costs and benefits are described as "incremental" to our "Business As Usual" case, as presented in Volume 2. As previously described, "full deployment" means changing out ninety-seven percent of our existing 4.9 million meters over a five-year time period, and building the communications infrastructure to allow us to read ninety percent of these meters remotely.

A. Scenario 1: Full Deployment Operational Only - Utility Implemented

In this subsection we describe the operational costs and benefits we expect will result from full deployment by SCE of the AMI metering and communications infrastructure. These costs and benefits have been quantified using the Ruling's assigned cost and benefit codes. We also present a discussion of the uncertainties and risk analysis for this scenario, as well as a discussion of the NPV analysis. As required by the Ruling, "this scenario assumes that no new tariffs are established as a result of the full deployment of AMI, so costs and benefits that derive from the rollout of new tariffs are excluded in this case."[11] The operational activities, processes, and procedures impacted by full deployment under this particular scenario were fully discussed in Section II above.

1. Costs

Appendix A of the Ruling classifies AMI deployment costs into six broad cost categories: Meter System Installation and Maintenance, Communication Systems, Information Technology and Applications, Customer Services, Management and Other, and gas service costs (which are not applicable in any of SCE's scenarios). The Ruling also establishes seventy-nine different cost codes applicable to these cost categories that must be used for analytical purposes. Under the "operation-only" full deployment scenario, we expect to spend a total of $986.7

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[11] Ruling, Attachment A, p. 7.

million including operational and capital investment related costs[12]. Table 3-5 below summarizes our estimated costs for Scenario 1 in the five cost categories.

Table 3-5 Summary of Costs for Scenario 1 (000s in 2004 Pre-Tax Present Value Dollars)	
Cost Categories	**Total**
Metering System Infrastructure*	$754,744
Communications Infrastructure	44,446
Information Technology Infrastructure	128,530
Customer Service Systems	39,745
Management and Miscellaneous Other	19,258
TOTAL:	$986,723

* Includes $2.156 million FSMRO severance cost.[13]

The following subsections provide our preliminary analysis of these cost categories along with the unique cost codes within each cost category.

a) Meter System Installation and Maintenance

(1) Start-up and Design

Appendix A to the Ruling does not identify any cost categories for meter system start-up or design. Any meter system start-up or design activities have been classified as installation costs and are discussed in the next subsection.

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[12] As specified in the Ruling, all costs are presented in 2004 pre-tax present value dollars unless otherwise stated.

[13] These costs were misclassified as an SB-1 cost in the preliminary analysis. They will be reclassified as an MS-1 cost for the December filing.

(2) Installation [MS-1 through MS-11]

The Ruling's MS-1 through MS-11 cost codes correspond to the costs associated with procurement, supply chain management, meter testing, installation and associated support costs. The following subsections describe our preliminary analysis of the costs of each of those cost codes.

(a) Meter Reader Transition Costs (MS-1)

(i) Residential and Small Commercial (< 20 kW) Meters

For the twenty-four service centers in our metropolitan areas, we assume that our current Field Services Representatives (FSRs) and Meter Readers will be selected for the project temporary installer positions, as discussed further in cost code MS-5.[14] A number of our existing Meter Readers will be upgraded and trained to fill the positions of the FSRs placed in the project temporary installer positions. There will also be vacancies in the Meter Reading staff as existing Meter Readers fill new positions such as supervisors, revenue protection investigators and administrative staff needed to support the AMI deployment. Beginning in 2006, we estimate that we will have 292 vacancies in our meter reading staff caused by employee movement to other areas to support AMI deployment. We plan to backfill those vacancies in early 2006.

A critical factor we considered when backfilling these positions is the productivity differential between a new meter reader and an experienced meter reader. During the first month, we assume that new Meter Readers will perform at 60% of the productivity standards of an experienced Meter

[14] The cost for the temporary installer positions are reflected in Cost Code MS-5.

Reader. Their performance steadily increases and by their sixth month, new Meter Readers must perform at similar productivity standards as an experienced Meter Reader. Given this productivity differential, we will need to hire 93 additional project temporary Meter Readers at the outset of 2006 in order to achieve the same levels of productivity we would achieve with an experienced Meter Reading staff. We assume that these 93 incremental Meter Readers will attrition out of the organization as productivity increases over the first six months. Our approach also incorporates the use of overtime. We have estimated that the overtime that will be worked is equivalent to 10.1 incremental full-time employees in 2006. The anticipated cost in 2006 is $7.1 million.

For the ten service centers in our rural areas, we will be relying on our existing FSRs to handle the installations. Existing Meter Readers will be upgraded and trained to handle the FSR job responsibilities to backfill for the FSRs taking the project temporary installers positions. We plan to backfill the vacancies in our Meter Reading staff with project temporary Meter Readers. We estimate that we will need 8 project temporary Meter Readers throughout the 2006 to 2010 deployment period at a cost of $2.0 million.

(ii) Complex Meters

In our service territory, we have approximately 356,000 meters that are considered complex and installations will therefore be handled by Meter Technicians. Given the aggressive deployment schedule, we will rely on both full-time resources (which are discussed in cost category MS-5) and contract resources. With regard to the contract resources, we will hire these employees to assist with the installations beginning in 2007. Our personnel estimates are based on an installation rate of five meters per day. The number of contractors will vary by year, ranging from twenty contractors in 2007 to thirty-one contractors in 2009. The costs associated with the contract employees are $7.1 million over the 2007 to 2010 timeframe.

(b) Supervision of Installer Workforce (MS-2)

With the addition of new staff (as discussed in the cost category descriptions for MS-1, MS-5, and MS-12), we will need to hire additional supervisors and support personnel. We forecast a need to hire an additional FSR supervisor for each of the twenty-four service centers in the metropolitan area. An additional Supervising Field Service Representative will be hired for each of the service centers to handle the rerouting of the remaining manual read accounts, oversee the distribution of work and the resolution of access issues. We also forecast that one administrative aide will be needed for each service center to handle customer contacts, arrange customer appointments and handle administrative personnel-related activities. We also expect to hire six project support personnel to assist with deployment tracking and reporting for all of our service centers in the metropolitan and rural areas. Finally, we expect to add one supervisor to handle the new revenue protection investigators that will be hired (as discussed in cost code MS-12). We estimate the cost of these seventy-eight incremental employees at $26.4 million over the 2006 to 2010 deployment timeframe.

(c) Cost of Purchasing Meters (MS-3)

Based on vendors' RFI responses, our preliminary estimate is that we will procure approximately 7 million meters at a cost of $493 million over the 2006 to 2021 timeframe resulting from the initial AMI deployment, replacing meter failures, and addressing customer growth.[15] We will procure five different meter types for the AMI deployment. Each meter will be equipped with an RFID tag to facilitate our procurement and supply chain processes. Sales tax was added to the meter cost.

To reach the ninety percent coverage required by the Ruling, we will procure 4.8 million meters to replace the existing meters throughout our service territory. Table 3-6 shows the types of meters, quantities, and unit costs associated with full deployment.

Table 3-6
Cost Table for Initial AMI Full Deployment Meter Purchases

Meter Type With Communication Module	Amount	Base Unit Cost	RFID Unit Cost
< 20 kW residential single phase	4,349,762	$50	$2
Residential single phase transformer rated	25,742	$50	$2
< 20 kW residential network	103,779	$130	$2
< 20 kW commercial	176,871	$320	$2
> 20 kW commercial	153,051	$700	$2
TOTAL	4,809,205	N/A	N/A

We will also incur meter equipment costs in addition to the AMI meter and RFID costs. We assume that each AMI meter will need to have a meter lock ring. We expect to be able to use fifty percent of the lock rings currently in place for the new AMI meters. Thus, we will need to procure new lock rings for the remaining fifty percent of the new AMI meters. Another

[15] Upon compiling this preliminary analysis, we discovered that our cost estimates are erroneously based upon procuring 7.4 million meters. In the formal application, we will update our cost estimates to reflect procuring nearly 7 million meters, as appropriate.

additional cost we expect to incur is associated with replacing the current A-base meters. For these meters, we must install an adapter to enable the meter change.

Our preliminary analysis shows that during the full deployment, we will have meters that fail after the three-year warranty period has expired. We estimate that there will be 1 million meter failures during the 2009 to 2021 timeframe based on our projected failure rate.[16] In those cases, we will need to procure and install new AMI meters at these meter sites. Table 3-7 illustrates the meter type and expected volumes associated with replacing these failed meters.

Table 3-7 Meter Failures - Out of Warranty Only (2009 Through 2021)	
Meter Type With Communication Module	**Quantity**
< 20 kW residential single phase	905,503
Residential single phase - transformer rated	5,293
< 20 kW residential network	21,602
< 20 kW commercial	36,358
> 20 kW commercial	31,459
TOTAL	1,000,215

In addition to installing AMI meters on existing meter sites, we will need to install AMI meters as we experience customer growth. We estimate approximately 1.2 million new meter sets during the 2006 to 2021 timeframe due to customer growth. Table 3-8 shows the expected meter type and volumes associated with these new meter sets.

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16 *See* Volume 2, Section III concerning how this failure rate was calculated.

Table 3-8 Cost Table for Growth Meter Purchases Only 2006 Through 2021	
Meter Type With Communication Module	**Quantity**
< 20 kW residential single phase	1,015,765
Residential single phase – transformer rated	8,917
< 20 kW residential network	24,235
< 20 kW commercial	61,267
> 20 kW commercial	53,016
TOTAL	1,163,200

(d) Installation and Testing Equipment Costs (MS-4)

Our analysis indicates that we will incur $25 million in installation and testing equipment costs over the 2006 to 2021 timeframe. With regard to installation equipment, over the 2006 to 2010 timeframe, we will incur costs for tools, equipment, materials, supplies, uniforms and vehicle costs associated with the new installers, meter technicians, meter readers, field service representatives, supervisors, and various support personnel. These costs will continue over the 2011 to 2021 time period for the incremental personnel remaining following the installation period.

We will also incur facility costs over the 2006 to 2010 timeframe. Current SCE service center facilities cannot house the required incremental personnel. Facilities will either be modified to handle the incremental personnel or portable facilities will be leased.

In terms of meter testing equipment costs, we will incur costs to reconfigure our Meter Shop facility to handle the increased workload for the AMI deployment. Seven new meter test workstations must be installed in the Meter Shop during the 2006 to 2007 timeframe. In addition, our material handling conveyer system needs to be upgraded because the existing conveyor will not accommodate additional workstations. We will also need to acquire an additional demand testing board to handle the increased workload for commercial meters.

(e) Installation Labor (MS-5)

(i) Residential and Small Commercial (< 20 kW) Meters

In order to support the aggressive deployment schedule discussed in Section II above, we estimate a need for 207 project temporary installers during the 2006 to 2010 timeframe. We base this estimate on the assumption that an installer in our metropolitan areas will install twenty-five residential meters per day or eighteen commercial/industrial meters per day.[17] The cost for the additional personnel to perform installations is estimated to be $66.3 million over the 2006 to 2010 timeframe.

(ii) Complex Meters

To meet the aggressive full deployment schedule required by the Ruling, we estimate that additional personnel will be needed to handle the 356,000 installations. Beginning in 2006, we will dedicate fifty-five Meter Technicians to full deployment. As the five-year deployment period progresses, we will commit additional resources to the project, peaking at 105 Meter

[17] Installation rates for the 104,256 meters covered by the rural installers are different because of the vast difference in geographic locations between meters. We estimate that rural installers will install twenty residential meters per day and five commercial/industrial meters per day.

Technicians in 2010. These resources will also need to work overtime in order to meet the annual installation targets. We have estimated that the overtime that will be worked is equivalent to between twenty-three and thirty-six incremental full-time employees throughout the 2006 to 2010 timeframe. Our personnel estimates are based upon the assumption that a Meter Technician can install an AMI meter in 2.5 hours on average. The cost for the additional personnel is estimated to be $41.6 million over the 2006 to 2010 timeframe.

(f) Meter Installation Tracking Systems (MS-6)

As discussed in Section III of Volume 2, we expect that there will be meter failures that occur throughout the deployment period. We plan to hire an additional analyst to assist with tracking the meter failures. The analyst will look for trends in the failure data so that we can resolve communication or product issues with the vendor. We estimate the cost for this additional activity at approximately $98,600 per year beginning in 2006.[18]

(g) Panel Reconfiguration/Replacement (MS-7)

When we replace A-base meters during the course of the deployment, we will need to install a socket adaptor in the panel. This socket adaptor allows the new AMI meter to be "plugged" into a customer's older electrical panel. We assume that just under two percent of all meter changes in any given year will be A-base meters requiring the socket adaptor. In addition, during the installation process, our installers may inadvertently damage the customer's

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[18] Upon compiling this preliminary analysis, we discovered that this cost is only reflected in 2006, but should occur through 2010. The overall cost for this cost category will be revised in the formal application, as appropriate.

meter panel. Although the meter panel is the customer's responsibility, we intend to pay the costs for any damages that occur to the panel while we perform the installation work. Based on our experience installing over 350,000 AMR meters, we incurred approximately $50,000 in damages associated with customer panels. For the purposes of this preliminary business case analysis, we relied on this experience to develop a per meter damage cost of $0.14. Overall, the costs associated with these activities are estimated to be $3.8 million over the 2006 to 2010 timeframe.[19]

(h) Potential Customer Claims (MS-8)

We expect to incur costs related to potential customer claims as a result of the AMI deployment. However, for purposes of this preliminary analysis, these costs have been reflected as part of the cost estimate for cost code MS-7 given that we were not able to delineate the customer claim related portion of the costs discussed above.

(i) Salvage/Disposal of Removed Meters (MS-9)

As installers remove non-AMI meters, they will return these meters to the service centers. We plan to contract with a salvage company to handle removing these meters from each of our service centers. As such, we have not assumed any incremental costs to handle these meters.

Throughout the meter deployment period, we anticipate that there will be meter failures in the field. Once the installer returns the meter to the service center, the meters that are still under warranty will be returned to the vendor for replacement. We will require additional personnel to

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[19] Upon compiling the filing of our preliminary analysis, we discovered an error associated with the cost calculation for this cost code and the overall estimate will be revised accordingly in our formal application as necessary.

handle the processing of the meters returned to the vendor. Over the 2006 to 2010 deployment period, we are estimating $0.63 million in labor costs for this activity.

(j) Supply Chain Management (MS-10)

As discussed in Section II of this volume, our PAMM group is responsible for receiving and stocking meters at our central distribution facility. We expect to add more personnel to handle the increased volume of meters that will be received and processed in the central distribution facility. During the 2006 to 2010 deployment period, we estimate the need for nine material handlers responsible for receiving the meters from delivery trucks, storing the meters within the warehouse, and staging the meters for distribution. We also forecast the need for three warehouse clerks to maintain the integrity of the inventory by processing receipts, conducting inventories, and tracking assets. We will need two heavy transportation drivers to deliver new AMI meters to our Meter Shop for testing and then out to the various SCE service centers for installation. Further, we anticipate the need for additional supervisory and project support personnel. Throughout the 2011 to 2021 time period, we will maintain additional personnel to process the meter failures in the field. This processing includes sorting, packaging and shipping the meters back to the supplier as well as receiving and tracking the meters when they are returned. We estimate the cost for the additional personnel at $7.9 million over the 2006 to 2021 timeframe.

Currently, our central distribution facility is at 95% capacity, housing and maintaining a monthly average of 25,000 meters. With full AMI deployment, we expect to increase our meter inventory to 100,000 meters monthly. A new facility will be required to house the meter inventory because our current facility cannot accommodate the volume of meters required for this deployment.[20] Given the forecast monthly meter volumes, we expect to maintain this facility until mid-2011. Other non-labor costs that we will incur from 2006 to 2021 are for miscellaneous equipment, packing supplies and freight costs for delivering materials to the service centers on a just-in-time basis. The estimated non-labor cost is $7.1 million over the 2006 to 2021 timeframe.

As the meters are delivered to the various service centers, additional personnel are required to process the meters at the service center locations. This processing includes verifying receipt of the meter, scanning them into the Field Tracking tool, and resolving variances in expected versus actual deliveries. We estimate the need for fifteen additional employees to handle these activities at an estimated cost of $5.3 million over the 2006 to 2010 timeframe.

A critical assumption in our supply chain management analysis is that we will be utilizing RFID technology to facilitate the meter deployment processes. While this technology is being used in various industries, it is a new technology for us. Given the scale of the AMI deployment, we will engage consultants with experience in this technology to assist in the development of RFID implementation and deployment plans. We estimate a cost of $0.66 million in 2006 for these activities. Our estimate is based on cost information received from a potential vendor of these services.

(k) Training (Meter Installers, Handlers, and Shippers (MS-11)

For employee training needs, we looked at both the trainee-related cost of non-productive (seat) time spent in the classroom, as well

[20] The start-up costs for a new facility are detailed in cost category MS-11.

as the cost of the trainer and training staff. Depending upon an employee's position, they will have to take training classes, ranging from new hire meter reading classes to meter installation classes. We estimate that the seat time costs for our field personnel will be $3.5 million over the 2006 to 2010 timeframe. The cost associated with developing and delivering materials for these training classes is estimated to cost $0.5 million over the 2006 to 2007 timeframe.[21]

As mentioned in cost code MS-10, our current central distribution facility is at ninety-five percent capacity and a new facility will be needed to house the meter inventory. In addition to the actual facility leasing costs, we will incur equipment and supply costs to connect the new facility with our existing communications network. We estimate that we will incur $1.8 million in 2006 to make this facility operational.

(3) Operations and Maintenance

(a) Maintaining Existing Metering Systems (MS-12)

As meter failures occur throughout the deployment period, replacement meters will need to be set. FSRs will handle this work. We estimate the need to hire additional FSRs beginning in 2006 to support the meter replacement activities. Our personnel estimates include costs for 2.8 full time employees (FTEs) in 2006, peaking at 28.5 FTEs in 2007, and reaching a steady state of 15.8 FTEs from 2011 to 2021. Our personnel estimates are based upon a replacement rate of twenty-five residential meters per day and eighteen commercial/industrial meters per day.

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[21] Upon compiling the filing, we discovered an input error calculating our training costs. The overall training estimate will be revised accordingly in our December filing.

Throughout the AMI full deployment, we expect our installers may discover potential energy theft situations that need further investigation. This assumption is based upon our experience with the van-based AMR deployment. We plan to hire additional revenue protection investigators responsible for investigating these potential theft situations. With the increased potential to identify possible theft situations, we expect to increase our current investigator staff from 16 to 32 investigators by 2007.

Currently, potential energy theft situations are usually brought to our attention by our meter reading staff. Given that a majority of the meter reading staff will be eliminated with AMI, we will hire three additional support personnel to analyze meter data to identify potential theft situations to be further investigated.

The labor costs for incremental FSRs, revenue protection investigators and associated support personnel are estimated at $37.4 million for the 2006 to 2021 timeframe. In addition to labor costs, we will also incur equipment costs of approximately $4.1 million for the same period for tools, equipment, materials, supplies, uniforms and vehicle costs associated with the new FSRs, revenue protection investigators and support personnel.

Additional non-labor costs are forecast for battery replacements in the AMI meters installed on the greater than 20 kW commercial accounts. Those meters contain a battery with a ten-year life. In 2016, we will begin the process of replacing these batteries and the replacement process will continue through 2021. We estimate the cost of the replacement batteries at $0.51 million.

As the AMI system is deployed, we anticipate new issues will develop from the implementation of new systems and the large number of meter changes. These will impact our ability to prepare and deliver accurate customer bills in a timely manner. We estimate the need for one FTE per year for project support to resolve AMI issues affecting billing. The estimated cost of this activity is $0.78 million over the 2006 to 2021 timeframe.

The "watts lost" rating of an electronic meter is typically greater than that of the single phase electro-mechanical meter it would be replacing. We estimate the average AMI meter would be rated at 1.9 watts higher than their single phase electro-mechanical counterparts. For our full deployment scenario, this would add 4 megawatts of load 24 hours a day, 365 days per year. This would equal over 35 million kWh per year in added energy consumption. No added cost has been included in this preliminary analysis to account for this loss, however we will likely include this as a Meter System O & M cost under this cost code in our updated December filing.[22]

(b) Pick-up Reads (MS-13)

When a meter fails, the failure can be caused by a registration issue or a communication issue. In either case, it will be necessary to send a Meter Reader to collect a pick-up read from that meter in order to maintain timely and accurate customer billing. We estimate that we will need to hire additional Meter Readers beginning in 2006 for pick-up reads. Our personnel estimates increase in 2007 once the communication network is operational and we start experiencing both registration and communication failures with the AMI meters. Our personnel estimates include costs for 1.3 FTEs in 2006, peaking at 12.7 FTEs in 2007, and reaching a steady state of 7.1 FTEs from 2011 to 2021. These estimates are based upon a pick-up read rate of 56 reads per day. The labor costs for this cost code are estimated to be $5.1 million over the 2006 to 2021 timeframe.

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[22] This would cost $2.8 million per year using the capacity and energy cost assumptions from the ruling.

Non-labor costs of $0.65 million will be incurred for tools, equipment, materials, supplies, uniforms and vehicle costs associated with these new Meter Readers.

(c) Meter Replacement Costs (MS-14)

We described the labor costs that will be incurred for replacing failed meters and collecting pick-up reads associated with failed meters in cost codes MS-12 and MS-13. In cost code MS-14, we captured the costs for performing meter replacements on new meter sets that have failed. The labor costs for this cost code are estimated at $0.26 million over the 2006 to 2021 timeframe.

As we described in cost code MS-12, we will need to replace the batteries for the AMI meters that are installed on the greater than 20 kW commercial accounts. The labor costs to perform this battery replacement are captured in cost code MS-14. Our estimates of $3.5 million include costs for 14 FTEs in 2015, peaking at 20 FTEs in 2019, and tapering off to 2 FTEs from 2020 to 2021.[23]

b) Communications System

(1) Start-up

(a) Review/Specify Security System (C-1)

As we design our new communications infrastructure, it will be necessary to assess the systems needed to ensure the security of the data transmitted within the network. We plan to engage contractor

[23] Upon compiling this preliminary analysis, we discovered an error associated with the cost calculation for this cost category. The costs will be revised in the formal application, as appropriate.

resources to assist us with this assessment. The costs for this assessment will be incurred in 2006 and are estimated to be $72,800.

To ensure the accurate transmission of data from the meter to the billing systems, we will dedicate personnel to review the operational design and system requirements. We estimate the need for additional personnel for these activities from 2006 to 2008 timeframe at a cost of $0.40 million.

(b) Network Placement Site Surveys (C-2)

There are no incremental costs associated with this cost category.

(c) Mapping Network Equipment on Company Facilities (C-3)

We will incur incremental labor costs during the 2006 to 2007 installation timeframe necessary to map MCC take-out point installations. Engineers will need to determine appropriate placement of the 181 MCC take-out points within SCE's service territory. Once the MCC take-out point locations have been identified by the engineers, communication technicians will be responsible for installing the equipment. The labor costs associated with replacing failed MCC take-out points are also included in the estimate for this cost category. Overall, we estimate the labor costs for these activities at $1.26 million.

We plan to utilize contract personnel to handle the installation of the collectors, packet routers and the antennas for the MCC take-out points throughout the entire deployment period. The contract personnel will handle the replacement of any failed equipment as well. Contract personnel will also be utilized during the battery change-out process, which is described in more detail below. The contractor labor and vehicle costs associated with these activities are $5.0 million.

(d) Staging Facilities for WAN/LAN Equipment and Mounting Hardware (C-4)

For the communications infrastructure, we will configure and test 100% of the network infrastructure equipment before it is deployed to the field for installation. The labor costs associated with performing these activities on 9,600 collectors, ninety-six packet routers, and 181 MCC take-out points are estimated at approximately $0.96 million for the 2006 to 2010 deployment period.

In terms of maintaining the communications infrastructure, we currently do not have a facility that can accommodate the eighty-five FTEs needed to maintain the communications network (these personnel costs are further described in cost category I-15). Our cost estimates includes the lease costs for a new facility which will continue over the 2006 to 2021 time period. In 2006, we will incur facility set-up charges such as costs to connect the new facility to our existing communications network. Overall, the costs associated with this facility are estimated at $3.5 million over the 2006 to 2021 timeframe.

(e) Review/Develop Strategies to Retrieve/ Process Data from Meters (C-5)

In determining the appropriate strategies to retrieve and process meter data, we evaluated IT application solutions. Given the data retrieval and processing requirements associated with AMI, we developed new applications or, in some cases, enhanced existing applications to handle these requirements. Section II details the various IT application solutions that need to be developed or enhanced in the areas of meter supply chain management, meter change workflow, and meter read conversion. We have estimated approximately $0.20 million in contractor costs associated with the IT application solution design.

Our Billing and IT organizations will work jointly to determine the system requirements needed to prepare and deliver accurate bills in a timely manner based on data retrieval from AMI meters. We estimate $0.18 million in project management and business analyst support labor costs for these activities over the 2006 to 2008 timeframe.

(2) Installation Costs

(a) Auxiliary Equipment (C-6)

Our analysis indicates that we will incur $4.4 million in auxiliary equipment costs over the 2006 to 2021 timeframe. With regard to the communications infrastructure, auxiliary equipment for the MCC take-out points and collectors is required in order to make the infrastructure operational. For the 181 MCC take-out points, antennas and various equipment will need to be installed on each unit. Each of the 9,600 collectors will be equipped with a battery, which is estimated to have a six year life. This battery is required so that data is not lost in the event of a power failure. Beginning in 2012, we will need to begin changing the batteries in the collectors. In order to minimize installation error, we will provide the contractor personnel handling the equipment in the field with refurbished equipment that allows them to avoid changing the batteries in the field. In 2012, we will purchase 100 new collectors to begin this battery change-out process. The collectors that are removed from the network will be retrofitted with the new batteries and then redeployed to the field.

For the AMI meter installations, there will be a subset of meters that require an external antenna installation so that the meter can communicate properly with SCE's network. We assumed in our preliminary analysis that, based on information from the RFI response, one percent of all residential and less than 20 kW commercial meter installations will require an external antenna. For greater than 20 kW commercial meter installations, we estimate that twenty percent of the installed meters will require an external antenna. This assumption is based upon our experience with the RTEM Project. The majority of the antenna costs will be incurred during the initial deployment period in the 2006 to 2010 timeframe. However, the costs will continue through 2021 to reflect replacement costs for failed meters in addition to new meter sets related to customer growth. Overall, we estimate the cost at $14.6 million over the 2006 to 2021 timeframe.

(b) Pole Replacement (C-7)

We do not forecast that there will be any pole replacements required to support full deployment and thus we do not estimate any costs for this cost code.

(c) Communications Link from Meters to Data Center; WAN/LAN Servers (C-8)

We do not forecast any incremental costs for this cost code.

(d) Install Cross Arms/Mounting (C-9)

We do not forecast any incremental costs for this cost code.

(e) Purchase Network Communication Equipment and Hardware (C-10)

Over the five-year deployment period, we plan to install 9,600 collectors. The majority of the installations will be complete by July 2007, at which time the network will become operational. Once the radio frequency networks are operational, we will be able to determine the specific areas within our service territory that are not communicating with the network and determine whether a collector can be deployed to cover that location or whether it will be a RF "blind spot," and will not possess remote read capability. We also plan to install ninety-six packet routers. We will need to install packet routers to ease congestion on the network and enable data to be transmitted to the network in a timely manner. The equipment costs for the 181 MCC take-out points are also included in this cost code. Each MCC take-out point will need to have four radios installed to make the unit operational.[24] Overall, the estimated costs for the network communication equipment are $13.7 million.

Table 3-9 describes the annual deployment volumes associated with the communication infrastructure.

Table 3-9
Communications Infrastructure Deployment Volumes

Equipment	2006	2007	2008	2009	2010
Collectors	5,333	2,902	455	455	455
Packet Routers	62	34	0	0	0
MCCs	120	61	0	0	0

Throughout the course of the full AMI deployment, we expect equipment failures to occur. These failures will require us to incur additional labor and material costs to replace this failed equipment. Based on information from the RFI response, we assumed an annual equipment failure rate of 0.5% in our preliminary analysis.

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[24] Other equipment is also needed to make the MCC take-out point operational. The costs associated with this equipment are discussed in cost code C-6.

As meters are installed, the installers and meter technicians will utilize an RF tool to verify that the communication module is functioning properly. We will also procure LAN assessment tools to help troubleshoot problems when we determine meters are not communicating with the network. We estimate costs for procuring this equipment in 2006 at $0.23 million.

(f) WAN/LAN Training (C-11)

We do not forecast any incremental costs for this cost code.

(3) Operation and Maintenance Costs

(a) Cost of Attaching Communication Concentrators (C-12)

We do not forecast any incremental costs for this cost code.

(b) Contracts to Retrieve Meter Data (C-13)

We do not forecast the need for contracts to retrieve the meter data and services and have not forecast any incremental costs for this cost code.

(c) Dispatch and O&M of Field WAN/LAN and Infrastructure Equipment (C-14)

We do not forecast any incremental costs for this cost code because there are no dispatch and O&M costs associated with infrastructure equipment.

(d) Electric Power for LAN/WAN Equipment and/or Meter Modules (C-15)

We do not forecast any incremental costs for this cost code.

c) Information Technology and Application

(1) Start-up and Design

(a) Network Planning/Engineering (I-1)

As discussed above, we will install a communications infrastructure comprised of collectors, MCC take-out points, and packet routers. Thus, we expect to incur incremental labor costs of $2.5 million over the 2006 to 2010 period in this cost code for the engineers and project support staff to design this infrastructure.

(2) Installation

(a) Computer System Set-up (I-2)

The full deployment of AMI will require us to enhance our computing systems through the development of new applications and the enhancement of existing applications. To accommodate these changes to our computing infrastructure, new hardware and operating systems, including 71 servers and 1,680 Gb storage, will be required. Because we plan to use the RFID technology in our supply chain management activities, we will need to acquire equipment to make this technology operational. The equipment we will procure includes dock door portals, barcode readers, hand-held readers and laptops. Additionally, we expect to automate the asset tracking and work order aspects of the meter installation and removal processes. This will require us to upgrade existing field laptops and provide additional laptops with GPS capability for the installers.

Incremental SCE FTEs and contractor resources will be required to handle the design and installation of the new hardware. We estimate the costs for computing systems set-up and associated labor at $12.2 million.

(b) Data Center Facilities (I-3)

We do not forecast any incremental costs for this cost code because no new data center facilities are required for the full AMI deployment.

(c) Develop/Process Rates in CIS (I-4)

Full AMI deployment will require us to develop new applications and enhancements to existing applications to properly support processes such as meter supply chain management, meter change workflow, and meter read conversion processes. A critical element of this effort will involve verifying that the new application or enhancement does not adversely affect existing systems that process meter changes and meter reads and calculate bills. We plan to use various comprehensive (and generally accepted) testing techniques, such as regression, integration, unit and system testing. We will engage contractor resources to handle these testing activities during 2006. We estimate the cost for these activities at approximately $25,000.

(d) New Information Management Software Applications (I-5)

The full AMI deployment will require us to automate the procurement processes in our Meter Supply Chain System. The preliminary analysis for this cost code assumes that the Meter Supply Chain automation project described in the 2006 GRC is deemed reasonable and receives cost recovery.[25]

The major drivers for the Meter Supply Chain System changes include: supply chain software enhancements and configuration for meter procurement process; support for RFID additional software enhancements related to tracking meter volume and deployment schedule; and integration with other systems in the meter deployment workflow. The Meter Supply Chain System proposed in our 2006 GRC will also need to be reconfigured to enable the "embedded" modules to support the procurement processes for the AMI meter. Additionally, these enabled modules will require integration with several other procurement management-related systems, including vendor management, asset management, and financial management systems to create a highly automated system to support the end-to-end meter supply chain business process from meter vendor to field installation. Overall we estimate that the system reconfiguration and the related system changes will cost $13.6 million over the 2006 to 2021 timeframe.

(e) Records (I-6)

We expect that new applications will be developed and existing applications will be enhanced to support automating the

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[25] *See* SCE's 2006 GRC NOI

meter change workflow and meter read conversion processes to accommodate the meter change volumes. The costs associated with developing the system requirements and database schema are captured in this cost code. Application development and enhancement is primarily performed by contractor resources. We estimate the cost for these activities at $0.53 million over the 2006 to 2007 timeframe.

(f) Update Work Management Interface to Process Additional Meter Changes (I-7)

Another critical element of system enhancement and development is designing the interfaces between the various systems and verifying that they are working as designed to ensure that information flows appropriately. We will engage contractor resources to handle these activities during 2006. We estimate the cost for these activities at approximately $12,000.

(3) Operation and Maintenance

(a) Maintain Existing Hardware/Software that Translates Meter Reads into Bills (I-8)

Our Billing and IT organizations will work jointly to determine system requirements needed to gather usage data and translate it into billing data. Once the system requirements are identified, these organizations will also assist in the testing of new software. We estimate $1.2 million in project management and business analyst support labor costs for these activities over 2006.

As detailed in the description for cost code I-7, we will engage contractor resources to handle interface design and verification activities during 2006. For cost code I-8, we expect to use contractor resources as well and estimate the cost for these activities at $20,500.

(b) Process Bill Determinant Data (I-9)

As usage data is collected and processed, we expect that additional customer service representatives will be needed to manually process accounts that the system is unable to process due to usage validation failures. For this cost code, we estimate approximately $20.5 million including the cost for 7.2 FTEs in 2006, reaching a steady state of 28.1 FTEs from 2011 to 2021.

In terms of our IT systems, we will also need to dedicate resources to define the rules that will determine whether data is processed by the system or whether it needs to be reviewed manually by a customer service representative. We will engage contractor resources to handle these activities during 2006. We estimate the cost for these activities at $51,700.

(c) Contract Administration and Database Management (I-10)

We do not forecast any incremental contract administration costs for this cost code. The incremental costs for infrastructure database management are included in cost code I-16.

(d) Exception Processing (I-11)

As meter failures occur, we expect that these accounts will fail billing system validations and will require manual intervention. This manual processing involves determining how a bill will be processed when a meter failure occurs during the middle of a billing period. Depending upon the nature of the meter failure, a judgment call is often required to estimate usage. Of the total meter failures, we estimate that fifty percent will require manual processing. Thus, additional customer service representatives will be needed to manually process these accounts so that customers continue to receive timely and accurate bills. Our estimates for this cost code include costs for 3.1 FTEs in 2006, peaking at 10.7 FTEs in 2007, and tapering off to 4.5 FTEs by 2010.[26] The estimated cost of $1.9 million over the 2006 to 2010 timeframe for this cost code is based on processing five accounts per hour for the first three years. As employees become familiar with how to handle these accounts, we expect their productivity to increase to ten accounts per hour, beginning in 2009.

In terms of our IT systems, we will need to dedicate personnel to define and develop the process to handle exceptions. We will engage contractor resources to handle these activities during 2006. We estimate the cost for these activities is $62,500.

(e) License/O&M Software Fees (I-12)

Software licenses are required for the RFID technology solution incorporated in the meter supply chain management system. The estimates in this cost code include an initial software license fee and aggregate ongoing license fees of $3.9 million during 2006 to 2021.

(f) Ongoing Data Storage/Handling (I-13)

The incremental costs associated with ongoing data storage/handling have been captured in the estimates for cost code I-16.

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[26] Upon compiling our preliminary analysis, we discovered an error in the cost calculation associated with this cost code. We will update this number, as appropriate, in our final analysis.

(g) Ongoing IT Systems (I-14)

As previously discussed throughout this section, full AMI deployment will require us to develop new applications and enhance existing applications to facilitate the meter supply chain management, meter change workflow, and meter read conversion processes. The ongoing O&M costs for these applications include applications support, security administration, database administration support, and maintenance and enhancement activities associated with the portfolio of applications that have been developed or enhanced to support AMI. The costs in this category are comprised of both contract and SCE labor. We estimate the costs for the activities in this cost code at $8.4 million during the 2006 to 2021 timeframe.

(h) Operating Costs (I-15)

The fully operational communications infrastructure will contain 168,000 commercial meters with radios, 9,600 collectors, 96 packet routers, and 181 MCC take-out points. As the infrastructure develops during the deployment period and beyond, we will need to phase-in additional personnel to handle the on-going management of this network. By 2010, we estimate that we will need eighty-five incremental personnel. We will utilize a mixture of full-time personnel and contractor resources to meet this need. Based upon our current experience with managing the network, we assume that we will need twenty engineers and IT specialists for every 40,000 radios. We forecast the incremental SCE labor costs from 2006 to 2021 at $31.9 million and the incremental contractor costs from 2006 to 2021 at $13.2 million.

(i) Server Replacements (I-16)

We assume that the computing systems hardware identified in cost code I-2 will be refreshed on a five-year technology refresh cycle. For purposes of this preliminary analysis, a hardware refresh would occur in 2011 and again in 2016. As discussed in Section III of Volume 2, we did not include a final refresh in 2021 based on our assumption that the entire AMI system will be obsolete and need to be renewed with new technology and supporting infrastructure. The design and installation of the new hardware will be handled by contractor and incremental SCE resources, the costs of which are included in this cost code. Incremental SCE labor costs for database management are also included in this cost code. We estimate the costs for refreshing the computing systems and associated labor at $18.5 million.

d) Customer Service Systems

This section describes the Customer Services Systems related cost codes utilized in assigning costs for the "operational only" full AMI deployment scenario. Call Center, Meter Order Processing, Customer Communications and a portion of Billing-related costs are included in this cost category.[27] This section will not include meter reading and field services costs, because these functions are essential to the Meter System Installation and Maintenance costs as previously discussed in this volume.

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[27] The majority of our billing system installation and operating costs are included in the Information Technology section (Section 1.(c) above) because cost codes I-9 and I-11 better described the billing related functions of "validating and creating billing determinate data" and "Exception Processing."

(1) Start-up and Design (None per ACR)

Appendix A of the Ruling did not identify any "start-up and design" related costs in the Customer Service Systems categories. We have, however identified some billing related "start-up" costs. This includes the need for approximately 1.65 FTEs in 2006, going up to 3.16 FTEs in 2008 as the full deployment scenario reaches its peak installation phase. These billing related start-up costs are associated with the specification of security systems, the development of data retrieval strategies, network planning, and the meter RFP proposal specifications. These costs are included under cost codes C-1, C-5, I-1, and M-2.

(2) Installation (CU-1 through CU-4)

This section describes the one-time costs that are expected to be incurred during the installation process for AMI. Generally, these costs are attributable to the implementation process itself, rather than on-going operations. For the most part, these costs will no longer be incurred once the project installation phase is complete.

(a) Customer Records, Billing and Collections Work Associated With Roll-out of the Meter Change Process (CU-1)

The majority of costs in this cost code relate to the processing of meter orders. Meter order processing costs are based entirely on the volume of anticipated meter change orders in excess of those that would normally be processed in the Business As Usual case. These costs are driven by routine change orders that fail to process initially in the automated meter processing system and must be manually reviewed as an exception and reprocessed.

This is a labor intensive process that is estimated to cost $24.2 million through 2021.

We anticipate a need for additional Billing personnel to support the revenue protection activities. As discussed in cost code MS-12, we expect our installers to discover potential energy theft situations that need to be investigated during the deployment process. Our Billing Organization will contribute to the resolution of these potential energy theft situations by performing analysis, interfacing with the field personnel, potentially rebilling customers' accounts, and corresponding with customers. We estimate approximately $780,000 in labor costs for these activities over the 2006 to 2021 timeframe.

(b) <u>Increased Call Center Activity During Installation Phase of the Full Deployment Operational Case (CU-2)</u>

We expect impacts on our Call Centers to be minimal for the operational-only full deployment case. We expect that a relatively small volume of calls will result from mass market media messages introducing the change to the affected customers. We also expect a very low response rate of 0.5% (one half of one percent) of customers impacted in the deployment year who will call us as a result of mass communications. This estimate is based on prior experience with similar mass communication campaigns. We expect a slightly larger volume of calls will occur as a result of the initial "meter change letter" that will be sent to all affected customers during implementation. We estimate that three percent of customers will call if only a letter or bill insert is sent and four percent if door hangers are left after service is complete. The three percent and four percent estimates are based on our experience with other communications in which a service visit is required. In total, call volume is expected to increase during the installation phase and is expected to peak at approximately 52,000 additional calls per year in 2009, dropping to zero by 2011. This would require the addition of slightly more than four FTEs during the peak installation stage.

(c) Modification and Customer Support Costs for AMI Integration to the Outage Management Systems (CU-3)

SCE's Outage Management System (OMS) is expected to function as it does today, entirely independent of the new AMI infrastructure. Thus, we have not identified any incremental implementation costs related to OMS for this cost code.

(d) Process Meter Changes for New Meter Installations and DA Accounts (CU-4)

We forecast that our Meter Services Organization (MSO) will incur costs of approximately $2 million (22 FTEs) in 2006, dropping down to $0.5 million (5 FTEs) in 2010. Total MSO costs for the activities in this cost code are expected to be $4.3 million. These activities include engineering and sample testing of meters prior to installation. The bulk of MSO metering installation work is classified as Meter System Installation costs in cost code MS-5. The Billing Organization has allocated approximately $5.3 million to the CU-4 cost code through 2010 for exception processing work directly related to meter changes during the installation phase. We did not forecast any costs in this cost code after the installations are completed in 2010.

(3) Operation and Maintenance (CU-5 through CU-10)

Cost code CU-8 has to do with "rate changes" and is not applicable within this operational-only scenario. Cost codes (CU-6 and CU-7) have to do with reduced customer safety and alternative safety measures, "because meter readers are no longer available." Although we recognize there is some foregone operational benefit in no longer having meter readers periodically inspecting our metering installations, we have no records relating to the frequency or value of our meter readers finding unsafe, or faulty electrical service equipment. Thus, we have not included any estimate of this cost in those two cost codes.

(a) Additional Rate Analysis (CU-5)

Even though there would be no new rates introduced under this operational-only scenario, we expect some increase in on-going rate analysis work in our Billing Organization due to an increase in the number of customer inquiries spurred by the large number of meter changes taking place. This results in 1.5 additional FTEs and a total cost of $1.1 million through 2021 in this cost code.

(b) Customer Support for Internet Based Usage Data Communication (CU-9)

We expect increased costs of approximately $1.2 million annually in our Billing area for the internet billing process as a result of full AMI deployment. These costs relate to the design, development, testing and implementation of internet growth to accommodate customers that utilize internet-based usage data.

(c) Outbound Communications (CU-10)

We do not forecast any incremental outbound communications or mass media marketing costs for this scenario. These costs will become very evident in the Demand Response scenarios to be discussed later in this Volume.

e) Management and Miscellaneous Other Costs (M-1 through M-15)

These cost codes include general overhead costs that span across two or more functional cost categories, such as project management and the administration of job skills training.

(1) Management and Miscellaneous Start-up and Design Costs (M-1 and M-2)

(a) Buyout of Existing Itron Contract for Automatic Meter Reading (M-1)

In 1999 and 2000, SCE installed and implemented a large AMR program. This program included 350,000 meters equipped with electronic ERTs which provided the means to read meters automatically from a van being driven past each meter location. The task of driving by each meter site on a monthly basis and collecting the metered data was outsourced to ITRON under the terms of a ten-year contract, which will expire in 2011. For purposes of this AMI program analysis, the original $11 million capital cost of the Van-Based AMR program and the entire cost of the eleven-year contract are considered to be “sunk cost.” This means we believe none of this investment, including the contractual commitment, can be recovered other than by having ITRON serve out the terms of the contract. Because we are already reading these meters automatically, we expect no incremental operational benefit will be derived from including these existing AMR meters in the AMI program. Because ITRON actually owns the ERT component of these AMR meters, a significant part of the annual contract cost goes toward ITRON's own capital recovery and it is unlikely that ITRON would forego future remuneration under this contract.

For the full deployment scenarios, we would attempt to recover as much operational benefit as possible from the existing contract by leaving the AMR meters in place as long as possible and having ITRON continue to read the ERT meters until the final phase of the AMI installations. Although we assume SCE will need to pay any remaining contractual obligation to ITRON in order to complete the contractual commitment, no cost has been included in this preliminary analysis for reaching such a settlement in the final year or two of the contract.

(b) Meter RFP Process and Contract Finalization and Administration (M-2)

The development and review phases of the RFP process are expected to involve the participation of the major SCE departments participating in the project. As a major participant in this process, the Billing Organization has included a portion of an FTE and about $62,000 over the first three years to this cost code. All other participating organizations have included the costs associated with this process in the direct overhead costs associated with their respective start-up and installation cost estimates. The PAMM Organization costs related to the preparation and review of the RFP were included in cost code MS-10, which was discussed earlier in this volume.

(2) Management and Miscellaneous Installation Costs [M-3 through M-11]

(a) Customers' Access to Usage Information (M-3)

We estimate the need for 1.5 FTE and approximately $1.2 million through 2021 in the Billing Organization for this cost code. This is for expected costs related to increased support of customer requests for more detailed usage information.

(b) Employee Communication and Change Management (M-4)

We have included 0.23 FTE and approximately $244,000 through 2021 for the Billing Organization for this cost code. This estimate is for expected costs related to preparing and communicating system and rate change information to employees and keeping them informed and up-to-date on the implementation of AMI and its related systems.

(c) Employee Training (M-5 and M-10)

There are two elements to employee training costs; the trainee related cost of non-productive (seat) time spent in the classroom, and the cost of the trainer and training staff, including training materials, classroom preparation, etc. All "trainee" related costs are included in the operational costs of each individual operating organization. Most of the training will be provided by our Job Skills Training Organization (JST), whose costs are included here and under cost codes M-10 and MS-11. The Billing Organization and the Call Centers supplement the JST training with their in-department training as needed. Meter System installation training was included in the MS-11 cost code as discussed previously in this volume. The M-5 cost code includes "systems and rate structures training." Training of Call Center personnel, meter readers, and meter test technicians is included in cost code M-10.

In the full AMI deployment scenario, we estimate there will be cost increases to develop and deliver training for all CSBU employees. CSBU employees include: Billing, Call Center, Credit and Payment Services, Field Services & Meter Reading (FSMRO), MSO, Major Customer Division (contact personnel and customers), and Rural Office personnel. Training will consist of communications, overviews, rates, processes, policies, and procedures related to AMI. Additional new-hire and enhancement training will be required for Billing, MSO (Meter Order Process), and FSMRO in support of AMI. Table 3-10 summarizes our estimated training costs related to implementation of the operational-only full deployment case.

Table 3-10
Training Costs by Cost Code
(Full Deployment Costs in 2004 P V $)

Cost Code	Costs through 2021
M-5 (Systems and Rate Structures)	$0.8 million
M-10 (Call Center, Meter Readers, Meter Techs.)	$1.3 million
MS-11 (Meter Installers, Handlers, Shippers)	$5.8 million
Total	$7.8 million

(d) <u>Meter Reader Reroute Administration (M-6)</u>

The cost of recycling and rerouting meter reading for the 10% of meters that will not be read remotely through the AMI network has been accounted for in cost code MS-1, as discussed previously in this volume. These costs are being absorbed as a portion of the cost of the one additional supervising FSR assigned to each of the 24 districts to supervise the AMI meter system installation process. MSO has included a total of $175,000 in this cost code over the duration of the analysis period.

(e) Overall Project Management Costs (M-7)

Implementation of AMI will require the formation of a project team to be made up of management representatives from each of the key operational areas. Each of the operating organizations has included the cost of their overall project management responsibilities in this cost category. In addition, we have assumed that an independent AMI Project Management Organization will be formed and made responsible for the overall coordination required to assure that all program goals and objectives are met in a timely and cost effective manner. The Project Management Organization would consist of three middle management and two staff support personnel, for the duration of the installation phase of the project. The estimated cost of the Project Management Organization will be approximately $6.5 million initially in 2006, dropping down to $1.6 million by 2010 and leveling off at $1 million through the end of the project in 2021. This will total approximately $15.3 million through 2021 in 2004 present value dollars.

(f) Recruiting of Incremental Workers (M-8)

We expect that implementation of full AMI deployment will severely affect the recruiting and hiring process within the three most heavily impacted organizations; Meter Reading, Call Center, and Billing. For the most part, the incremental cost of recruiting the anticipated increase in personnel has been included in the cost estimates for each organization separately in their respective cost codes. Because of the initial start-up impacts on FSMRO personnel, that organization has included $225,000 in this cost code.

(g) Supervision of Contracts and Technology Personnel Assigned to Hardware and Systems Development (M-9)

These costs are reflected within the individual operational areas. Thus, we did not forecast any additional costs under this cost code.

(h) Training for Other Traditional Classifications (M-10)

As described in Part (c) above the training costs included in this cost code are expected to be $1.3 million.

(i) Work Management Tools (M-11)

Our Business As Usual operations discussed earlier in Volume 2 include the cost of providing our management with the most up-to-date work management tools available. Thus, no incremental cost has been included for new or additional work management tools in this cost code for any of the AMI deployment scenarios.

(3) Operation and Maintenance [M-12 through M-14]

Capital and financing costs (M-12) are included in the NPV calculations at SCE's long-term weighted average cost of capital. Alternative methods of financing are discussed in the outsourcing scenarios (Scenarios 2 and 15). There is no change in the cost associated with mid and off-peak loads (M-13) under this scenario. Customer acquisition and marketing costs (M-14) will be discussed in the Demand Response scenarios and do not apply to the operational-only scenario.

2. Benefits

Table 3-11 summarizes the total estimated benefits we expect will result from the full deployment of AMI in the operational-only case.

Table 3-11
Summary of Benefits for Scenario 1
(2004 Pre-Tax Present Value Dollars)

Benefit Categories	Total
Systems Operations Benefits	$272.3 million
Customer Service Benefits	4.9 million
Management and Other Benefits	64.4 million
Demand Response Benefits	-0-
TOTAL:	$341.6 million

a) System Operations Benefits [SB-1 through SB-13]

In this section we will address the potential "system operations benefits" expected to result from full deployment of AMI to approximately 4.8 million SCE customers. Appendix A of the ACR identified 13 such potential benefits that may occur. In our initial review of these potential benefits, we have been able to quantify $272.3 million in savings, coming from only three of the 13 areas. We expect some net benefit from three others, which we are not able to quantify at this time. The remaining seven potential areas of benefit identified in the ACR are either already being experienced by SCE, have associated costs that more than offset the anticipated savings, or do not apply to the operational-only scenario. Two of the potential areas of benefit (SB-9 and SB-12) apply to the

Demand response scenarios (Scenarios 3 through 11). The following subsections address all 13 of the identified potential areas of system operations benefits.

(1) SB-1 Reduction in Meter Readers, Management and Support (SB-1)

This is the single largest area of benefits expected to accrue from full scale deployment of AMI. We currently employ approximately 570 meter readers and eighty management and support personnel, eighty percent of which would be eliminated with "full deployment" of AMI. As described above, full deployment of AMI will result in our ability to automatically read ninety percent of all our meters. The remaining ten percent, or approximately 480,000 meters, will continue to be read monthly by approximately 109 meter readers.[28] In addition, we expect to eliminate sixteen of the existing meter reader supervisor positions with full deployment of AMI.[29]

The reduction of eighty percent of our current meter reading organization would result in annual O&M savings of approximately $50 million and total savings of $239 million (expressed in 2004 PV dollars) savings over the duration of the analysis period. With our current attrition rate of thirty-five percent to forty percent annually, the reduction of meter reading personnel is expected to take place through normal attrition through the latter phases of AMI deployment, beginning with the actual activation of the AMI communications system (approximately eighteen months after AMI installations begin) and

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[28] The remaining 10 percent of the meters with which we are unable to communicate are scattered throughout the SCE territory and generally not adjacent to one another, thus making manual meter reading less efficient than it is today. Our assumption is that it will take 20 percent of the existing number of meter readers to read the last 10% of meters.

[29] These sixteen supervisory positions are incremental based on the number of supervisory personnel required today, without AMI. The actual Reduction in Force (RIF) will require severance of 24 supervisors, due to the temporary build-up of personnel to deploy AMI.

continuing throughout the deployment stages. Severance of the twenty-four supervisory personnel will result in a one-time cost of $2.2 million in present value dollars.

(2) <u>SB-2 Field Service Savings (SB-2)</u>

SCE currently completes nearly half of its "turn-off" and "turn-on" meter orders without having to actually turn the meter on or off. This situation occurs when a "turn-on" order can be matched to a "turn-off" order for the same location, on or about the same day. Such orders can be completed merely by taking a meter read, which currently requires a visit to the site at an average cost of approximately $15 per order. Virtually all of these special meter reads for matched on/off meter orders could be eliminated and replaced with the daily AMI meter read. This benefit would result in savings of approximately $30 million over the duration of the analysis period (*i.e.* through 2021).

(3) <u>Reduction in Energy Theft, Identifying Broken Meters, Wrong Multipliers, and Metered Accounts not Being Billed (SB-3)</u>

In reviewing this "potential benefit," we were unable to identify any incremental savings that may accrue due to AMI. All three of these situations can be identified as readily (if not more readily) by a Meter Reader making a monthly observation of the meter installation. In the case of energy theft and broken meters, we believe these would be even harder to identify through daily meter reads, since physical tampering is not readily apparent through meter readings, and a zero read does not necessarily indicate a broken meter. Many broken meters continue to register consumption, though it may not be correct. Rather than identifying this as a benefit, we have actually identified it as a potential risk.

(4) Phone Center Savings from Billing Inquiry Reductions Due to More Accurate Billing (SB-4)

Billing inquiries today are received for several reasons, only one of which is an inaccurate meter read. Based on a study using 2003 data, 22,791 calls to the Call Center were a result of meter reading errors. We used this number as a percentage of all calls to determine the percent of calls in subsequent years that would be projected as meter read error calls. For purposes of this preliminary analysis, we assume that 100% of these calls will be avoided with the full deployment of AMI.

For full deployment, the following Table 3-12 shows the number of avoided calls that may result from the complete elimination of meter reading errors. Using 3,376 as the average number of Billing Inquiry calls answered per FTE in the Billing Inquiry specialty support group in 2003, we are estimating a levelized reduction of seven FTEs by 2010, for a total benefit of $3.5 million through 2021.

Table 3-12
Reduced Phone Calls – Full Deployment

Year	2006	2007	2008	2009	2010	2011
Reduced Calls	2,820	8,445	14,089	19,753	23,626	23,626

(5) Elimination of Rate Design Constraints Due to Meter Programming Limitations (SB-5)

Many currently-installed TOU meters would require re-programming in the field if the Commission ordered a change in the definition of time-of-use on and off-peak periods, seasonal definitions, holidays, *etc*. This programming limitation does not exist with AMI meters since they meter 15-minute and hourly consumption data.

This is a benefit that SCE is already obtaining as we are systematically changing all existing TOU meters to interval data recorders. However, we recognize this is a qualitative benefit, in so far as under the full deployment scenario, it could make more rate options readily available to all customers.

(6) <u>Outage Management System (OMS) Benefits (SB-6)</u>

SCE's transmission and distribution systems currently utilize a modern-day communications infrastructure that gives us all of the OMS functionality that would be expected under full deployment of AMI. In fact, it is this very communication infrastructure that will be leveraged by an AMI deployment. Thus, we expect no incremental OMS benefit from full AMI deployment.

(7) <u>Better Meter Functionality/Equipment Modernization (SB-7)</u>

The broader range of functionality of new electronic meters, such as those that would be used for AMI, provides advantages over the electro-mechanical predecessors. The most apparent advantage is the universal "one-size-fits-all" capabilities of the modern meter. Though there are still a number of variations in "meter forms," and instrument transformers are still the norm for large accounts, the number of variations is not nearly as broad as it once was. For the larger C&I accounts, we are already taking full advantage of this functionality benefit in the "Business As Usual" case. This more universal metering functionality is less evident among smaller C&I and residential accounts and is recognized as a qualitative benefit relating to AMI deployment.

In addition, the incorporation of two-way communications provides the potential for meter diagnostics and voltage verification that do not exist today. AMI meters would also provide the potential means to alert the customers of system peaks and could automatically trigger some form of direct load control. They could also provide a means to allow the customer to access their own metered data for use in reducing consumption during peak periods. These are all recognized as qualitative benefits because incremental costs are not available and no attempt has been made to determine the economics of including any or all of these functional options for this preliminary analysis.

(8) Remote Service Connect/Disconnect (SB-8)

We respond to over one million turn-on/turn-off service requests annually, and we disconnect and reconnect nearly one million additional meters for credit related, non-payment issues. Nearly one-half of the on/off service requests and all of the credit disconnects require the physical disconnection of service at the customer's meter. AMI meters could be equipped with a remote disconnect switch contained within the meter, which could provide the ability to "remotely" turn electric service on or off.

However, this is a costly option to be added to an AMI meter. A typical 200 amp disconnect switch (not including additional hardware/software necessary to activate) would cost approximately $150 to $200 per meter. We currently incur approximately $17 to respond to a next day on/off service order and approximately $24 for same-day service. Thus, the installation of a remote disconnect switch would only make sense where there is frequent customer turn-over (*i.e.*, student housing, apartment complexes, *etc.*) and/or where credit collection problems exist. Even with turn-over rates of two or three per year at any specific location, the cost effectiveness of this option is marginal at best. Therefore, we have not included the remote service connect/disconnect functionality in our technology selection, nor have we included any related benefit in any of the AMI deployment scenarios.

(9) Improved Meter Accuracy and More Timely Load Information (SB-9)

A new solid state meter is slightly more accurate over the full range of its rated load capability than its electro-mechanical predecessor. A cost savings has been estimated for reduced call volume relating to billing inquiries as described in SB-4 above. On the other hand, the potential for increased initial failure rates for AMI (as was the case with RTEM meters) has been identified as a potential risk and results in significant cost increases in the Billing Organization due to increased meter order and exception processing (see cost codes CU-1, CU-4, and I-11 above).

Since customer load information would be available in a more timely manner (*i.e.,* hourly, daily, weekly, *etc*.), it will provide some benefit to SCE with regard to forecasting accuracy and in reducing resource acquisition costs. These costs savings have been identified in Scenario 3 where our Energy Supply and Marketing Organization (ES&M) has included interval data collection and processing costs and forecasting benefits as part of the on-going operations.

(10) Distribution Planning and Design (SB-10)

In theory, AMI would give us the opportunity to aggregate coincident customer loads within any specific area in order to determine the demand on a distribution circuit or an individual distribution transformer. This would be a significant planning tool except that SCE already has a sufficient Transformer Load Management program in place that already provides this information for distribution planning purposes. As such, deployment of AMI would not create any incremental benefits in this area.

(11) Reduction in Unaccounted for Energy (UFE) (SB-11)

As described above, AMI could theoretically give us the opportunity to aggregate customer loads within any specific geographic area in order to determine the demand on any particular distribution circuit. It is not clear, however, how this aggregated load information will assist in identifying the source of UFE. In reality, distribution circuit loads are dynamic and cannot be assumed to be confined to any geographic area over any extended period of time. This is because sections of load are constantly being switched from one circuit to another during circuit interruptions, for routine maintenance, and for load balancing purposes.

We currently have the ability to analytically model system losses using customer load profile data compared to total system generation, and have concluded that the amount of UFE is not significant enough to warrant any further investigation of the sort suggested as a potential benefit under full AMI deployment.

An offsetting cost factor with regard to UFE is that the "watts lost" rating of electronic meters is typically greater than that of the single phase electro-mechanical meters they would be replacing. We estimate the average AMI meter would be rated at 1.9 watts higher than its single phase electro-mechanical counterpart. For our full deployment scenario, this would add 4 megawatts of load 24 hours a day, 365 days per year. This would equal over 35 million kWh per year in added energy consumption. No added cost has been included in this preliminary analysis to account for this loss, however we will likely include this as a Meter System O & M cost under cost code MS-12 in our updated December filing.[30]

(12) Self-Generation Monitoring (SB-12)

SCE currently has the capability of monitoring net energy delivered to (or received from) its self generating customers. Currently, metered data is billed on a monthly basis and none of our tariffs require "real time" monitoring. It is conceivable, however, that some demand response benefit could result from the ability to provide the customer with real time, interval consumption data, even under the current tariffs. No studies have been conducted, however to determine to what extent customers would respond to real-time consumption data, nor have we determined what the cost would be to provide the customer with real-time data. Thus, for purposes of the "operational only" scenario, we have not identified any net benefit to result from real-time net energy metering. This benefit will be discussed in the demand response scenarios (Scenarios 3 and 4), where it is conceivable that new rate designs could improve demand response when the customer is provided with real-time consumption information.

(13) Reduction in the Amount of Time Required to Implement New Rates or Load Management Programs (SB-13)

The SB-5 benefits addressed above recognized the ability to redefine TOU time periods, or seasons, without the need to physically reprogram meters in the field. The time required to make such a change with the majority of today's meters is actually prohibitive. However, for the vast majority of customers

[30] This would cost $2.8 million per year using the capacity and energy cost assumptions from the ruling.

on TOU rates, there has not been a compelling reason to redefine time periods or seasons in recent years. As will be discussed later in the demand response scenarios, the ability to implement new rates in a timely manner, especially rates with narrower on-peak periods (or variable peak periods), would be a significant qualitative benefit and would eliminate a major obstacle to periodically re-defining TOU periods when warranted.

Under this "Operational-Only" scenario, we see no incremental savings attributable to this potential benefit over our "Business As Usual" base case. This is because we are already replacing our existing pre-programmed TOU meters with IDR meters, thus we are already deriving the same benefit.

b) <u>Customer Service Benefits [CB-1 through CB-13]</u>

The ACR identified thirteen "additional" customer service benefits, most of which relate to billing and demand-side management, and all but one would require the availability of interval load data, which does not apply in this Operational-Only scenario. Thus, our review of these potential areas of benefit resulted in anticipated savings from only one of the thirteen areas of benefit for a total savings of approximately $4.9 million over the duration of this full deployment "Operational-Only" scenario. This savings is attributable to improved billing accuracy due to the elimination of estimated bills, timelier billing, and the elimination of meter accessibility problems (CB-1).

c) <u>Management and Other Benefits [MB-1 through MB-10]</u>

We expect to reduce costs by approximately $28 million over the duration of the analysis period by decommissioning eighty percent of our hand-held meter reading devices. Typically these devices would be replaced every five years. This is a cost that would no longer be incurred and is classified as a benefit in the

MB-1 category. We have also identified $36 million in savings in benefit code MB-4 for reduced meter inventories and inventory management expenses due to the expanded uniformity of metering models.

None of the remaining potential Management and Other benefits has been determined in this preliminary analysis to result in any significant savings over that currently derived in the Business As Usual case.

3. Uncertainty and Risk Analysis

As discussed in Volume 2 and in accordance with Attachment A of the Ruling, we performed a risk assessment of the operational costs and benefits for each full deployment scenario that could result from uncertainty or lack of data. The risk analysis we performed for this scenario is based on the specific cost and benefit data discussed in the sections above.

For analytical purposes, this operational risk assessment focuses on those cost and benefit codes that have estimates (in cumulative nominal dollars (i.e. 2006-2021) of $5 million or greater. Once the appropriate cost and benefit codes were identified, we developed the most likely high and most likely low ranges for each of the cost and benefit cost categories. Consistent with the Ruling, we then applied a Monte Carlo statistical approach to create a probabilistic range around our estimate.

For Scenario 1, the total present value cost estimate for full AMI deployment is $986 million. Five cost codes in Scenario 1 represent over sixty percent of the total cost for this scenario. The cost range for each of the five and the primary driver is highlighted. The most significant cost code (MS-3) in Scenario 4 is estimated at almost $500 million and involves meter and meter-related communications equipment obtained from a single vendor. We estimated a range for this cost code to be: plus twenty percent and minus five percent. This range is based on our historical experience with price differences that occur between an RFI and the ultimate final contract. We find that vendor price increases of as much twenty percent are due to better understanding of scope, warranty requirements, and contract terms and conditions. We based our estimate on vendor quotes we received in the RFI. The range also reflects the uncertainty of meter failure. Under this full deployment scenario our Billing organization estimate may vary in a range of plus twenty percent to minus fifteen percent depending on the number of exceptions processed. The meter and field communication installation costs may vary by as much as plus fifteen percent to minus twenty percent based on installation productivity. Our information technology computing systems lifecycle costs have a range of plus or minus forty percent due to the uncertainty of the data processing and storage required. Our software development costs ranged plus forty percent to minus fifty percent based on the uncertainty of the final design.

The primary operational benefits relate to the reduction in meter readers and result in aggregate savings of $244 million. We do not expect any variation because the forecast reduction is solely a function of the AMI system communication coverage that is designed to reach ninety percent of the meters. The other identified operational savings were less than the $5 million threshold we used for analytical purposes. As a result, we did not include any operational savings in the statistical analysis.

Using the cost ranges estimated above, the application of the Monte Carlo statistical analysis of costs resulted in a range of $957 million to $1.1 billion around the estimated cost of $986 million for this scenario. The statistical analysis indicates that our cost estimate has about a fifteen percent confidence. This means that the project has an eighty-five percent chance of overrunning. Our preliminary cost estimates do not include contingency. However, based on our analysis we should consider a contingency of approximately $70 million in our final application to reduce the risk of overrun. This contingency amount is the difference between our cost estimate and the value at the ninety percent confidence level.

4. Net Present Value Analysis

Our net present value analysis is summarized in Table 3-13.

Table 3-13
Summary of Cost/Benefit Analysis for Scenario 1
($Millions)

Costs	Benefits	Pre-tax PV	NPV of Rev. Req.
$986.7	$341.6	($645.2)	($1,120)

Costs and benefits for each business case scenario were estimated by the appropriate business units using current (2004) dollars for all non-labor costs, and job titles and estimated FTE employees for all SCE labor costs. All costs and benefits were estimated in 2004-dollars, escalated to the forecast year (2006-2021), and then discounted to 2004 present value[31] using SCE's long-term Weighted Average Cost of Capital (10.50%). Cost categories from the Ruling[32] were used to summarize planned expenditures, in nominal dollars, by category and year. Capital/expense, depreciation, and amortization analyses were performed for revenue requirements analysis without respect to the Ruling's Cost Categories. As shown in Table 3-13 above, this scenario results in a negative Revenue Requirement Present Value of $1,120 million and does not support the implementation of full AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the Scenario 1 analysis, plus the recovery of SCE's net

[31] Ruling, p. 12.
[32] Ruling, Appendix A.

investment in any removed meters, plus the rate of return and tax impacts of the AMI-related investments.

B. Scenario 2: Operational Only - Outsourced

1. Overview of SCE's Approach to Outsourcing Analysis

The Ruling requires a full deployment scenario that directs the utilities to include the costs and benefits of outsourcing certain functions, presumably so the Commission can compare whether there are cost savings from outsourcing beyond what it would cost for the utility to perform these tasks. We support this analysis in that it is important to do a thorough review of the cost of all options. Inclusion of this outsourcing scenario also provides a reasonableness check on the cost estimates presented in the previous section for SCE-implemented full deployment of the Operational-Only scenario (Scenario 1).

As discussed in greater detail below, SCE supports outsourcing in certain functions where it makes sense and does not negatively impact our other operations or customers. Indeed, we currently outsource several areas of our normal operations where it makes economic and business sense to do so, including a portion of phone center calls, payment services and a sizeable portion of software development. Similarly, there are a number of areas where it does not make sense to outsource, either for operational efficiency, customer confidentiality, or financial reasons. For this reason, the "post-meter reading" Billing and Call Center functions were excluded from the outsourcing estimates and their AMI related incremental costs were added back in for purposes of comparison to the base-case and to the other scenarios.

In preparing this preliminary analysis, SCE has focused its outsourcing analysis on integrated solution companies that have legitimate and sufficient experience in their respective industries and the financial wherewithal to fulfill their contractual obligations. As discussed in this volume, the costs of deploying AMI are significant. Given the high stakes and detailed planning involved in such an enormous undertaking as deploying nearly 5 million meters in five years, we would require that an outsourcer be able to fulfill its contractual obligations or be able to pay stiff penalties. Our customers and the AMI project would be impacted negatively if the outsourcer's only option was to file for bankruptcy protection because it could not deliver on its contractual terms. Consequently, for this preliminary analysis, SCE has focused on potential outsourcers of a certain caliber that could sustain the uncertainties of an untested full deployment of new technology and has not considered the possibility of outsourcing to a possible "one-transaction" company whose main source of business/profit/credit would be from its AMI contract with SCE.

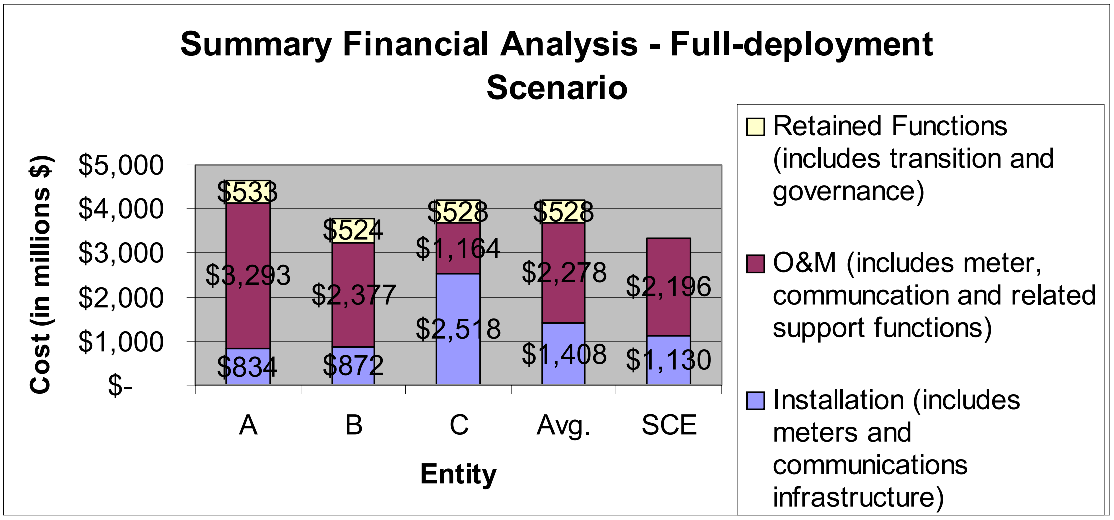
2. Overview of Results of Outsourcing Analysis

Our preliminary analysis indicated that potential integrated solution providers exist that have the corporate presence and capability to deliver the huge scope and scale contemplated for full deployment and would also be interested in responding to a formal bid process. Each of the integrated solution providers that participated in our preliminary analysis indicated that they would partner with multiple organizations to deliver the complete solution (*e.g.,* meter providers, software providers, communications providers, *etc.*). The integrated solution providers responded with complete outsourcing solutions that included all inherent components (*e.g.,* all related services, service levels, performance reporting, compliance, treatment of staff, governance considerations, technology, applications, *etc.*).

Due to the unique nature and scope of this undertaking, AMI by its very nature does not lend itself to taking advantage of many of the traditional outsourcing value propositions such as leveraging of shared resources, improved purchasing power, and faster implementation. AMI does not present the same degree of leverage that the more traditional outsourced functions offer. The nature of the work and the uniqueness of the customer base limit the opportunities to build highly leveraged and large scale service delivery models. We would be one of the first organizations to attempt outsourcing AMI on such a large scale (and the preliminary analysis indicates that for most service providers the scale would be greater than any other current customer AMI initiative). Being first may represent a risk profile greater than can be effectively absorbed.

The preliminary analysis does not indicate that there was a potential for significant economic value and concludes the outsourcing solution would be more expensive than an internal SCE solution. Figure 3-2 below summarizes the results of the three most viable outsource cost estimates compared to SCE's cost estimates for the same full-deployment scenario.

Figure 3-2
Summary of Financial Analysis of Outsourcing Scenario



3. <u>Economic Assessment</u>

Our preliminary economic assessment indicates that the savings opportunity associated with traditional outsourcing undertakings (such as IT, Finance, or HR) does not exist for outsourcing of AMI. The total cost to outsource the major elements of the full deployment scenario would be higher than the equivalent cost if we did the work ourselves. For full AMI deployment, the total cost of outsourcing (based on an averaging of the most complete integrated solutions provider feedback) is estimated at $4.2 billion, whereas SCE's cost is estimated at $3.3 billion (both in nominal 2004 dollars) for services beyond those considered solely for AMI (the outsourcing costs estimated included core activities beyond the scope of the AMI business case scenarios). To ensure an effective comparison, both the outsourced scenario and the internal scenario were developed with all components included (*i.e.,* representing the end-to-end AMI solution including "back office" functions) and with a consistent inflation (escalation) factor applied to all scenarios.

4. Overview of Approach

In order to comply with the Ruling, we undertook an initiative to analyze the potential to outsource some or all of the components for the implementation of AMI including acquisition, installation, operation and maintenance. The outsourcing analysis followed the same basic assumptions as the other scenarios for a full system deployment of meters and communication infrastructure to support various dynamic pricing rates, running from 2006 to 2021 with a five-year roll out period. The outsourcing analysis included four major components as follows:

- Data Sources (meter acquisition and financing, meter installation, meter testing, operations and maintenance)
- Data Transmission (communications network build-out, network management)
- Data Collection (meter read data processing, preparation of billable data)
- Data Usage (billing and settlement, internet communication, outage management)

The back-end component Data Usage (including preparation of billable data) was considered out of scope for outsourcing consideration. This determination was based on an assessment of current capability, current performance, cost effectiveness, integrated IT environment, sunk-investment, and customer relations.

a) The RFI Process

To gather information that could be used in analyzing outsourcing within the timeframe available, a high level data collection activity was undertaken which took the form of a modified RFI process, with iterative steps for data gathering/clarification or refinement. This process was completed over a timeline of approximately eight weeks. This process began with an evaluation of existing full service integrated solution providers that could potentially deliver the services that would be required in the outsourcing of AMI. The evaluation profile included the following:

- The provider had to be large enough in terms of sales, employees, and capitalization to be viable in an arrangement of the proposed magnitude.
- The provider had to have the capability to deliver an AMI solution.
- The provider had to have been delivering similar solutions or be a respected supplier of unique solutions.
- The provider had to be able to deliver the solution in a cost effective manner.
- The provider had to be able to show a low risk profile.
- The provider had to have the capability to respond in a very short one – two week timeframe.
- The provider had to be willing to bid on the services, if the services were outsourced.

Given the rapid response timeframe, the expected heavy interaction with the providers, the volume of anticipated questions, and the need to provide reasonably well priced solutions, we decided that only five integrated solution providers and one major meter provider would be included in the analysis. Additional potential providers exist, but due to the very short response timeframe, we chose to focus on those that best fit the profile, have the most experience, and were able to respond quickly.

The providers were asked to prepare a preliminary solution adequate to meet the requirements of the full deployment and partial deployment scenarios. Their solutions were to be reasonably consistent with available technologies, and executable under the specified parameters. They were to include a price estimate, including a financial (pricing) model, delineating when (or how) the charges will actually be incurred.

Three of the five integrated solution providers (providers A, B, and C) supplied a complete response while one (provider D) provided only a verbal representation of the solution and a cost formula. The solution attributed to provider D was determined to be too high a level of detail to be included in the preliminary analysis. The meter provider (provider E) provided a solution that was an initial deployment solution (with some high-level data points regarding ongoing O&M). Based on our concerns that the meter provider may not be able to effectively respond to the end-to-end delivery requirements of the AMI project, the response received from the meter provider was not included in the overall financial assessment.

For purposes of this preliminary analysis, all information received from the outsourcing providers, whether in documents or verbal communications shall be consistently treated as defined by the Non-Disclosure Agreements (NDA) executed between the providers and SCE. Outsourcing integrated solutions providers participating in this process will have no specific data attributed to a specific named provider.

b) Comparative Analysis

A baseline was created of the current meter organizations (FSMRO, MSO, and TDBU) using 2004 budget information and recorded costs through July 2004. This baseline was used to assess the in-scope labor component and to determine our retained functions. For the sake of expediency, the financial data provided by the integrated solution providers was normalized through a series of verbal communications with each of the service providers. Because each service provider responded in a different fashion, it was necessary to make model (price) changes for each response. This process also identified retained costs for SCE that would be considered as part of the end-to-end AMI solution and used in the comparison. A financial model was constructed that contains the following:

- Summary level presentation of both scenarios comparing integrated solutions provider response to our internal equivalent
- Detail models for each provider solution scenario (where it was possible to construct the financial analysis from the response provided)
- High level assumptions
- Categorization of cost codes (to indicate outsource, retain, or both)
- Detail models for out of scope activities that are required for AMI implementation
- Detail models for retained meter functions
- Table of escalation factors (used in all scenarios analyzed)

The financial information received from the providers is a high level assessment of the cost of providing the services, and must be classified as informational only. The accuracy and completeness of the financial information cannot be considered firm. Additional data gathering and analysis would be required to develop more reliable financial information (*e.g.,* through a formal procurement process such as an RFP).

5. <u>Summary of "Outsourcing" Findings</u>

Although outsourcing solutions are becoming increasingly sophisticated, deriving significant leverage in this defined AMI scope appears to represent a significant challenge. Our initial analysis indicates that outsourcing AMI does not provide enough of a value proposition to support the full scope and may introduce additional risk.

There were five integrated solution providers that participated. Each provided varying degrees of completeness and each had somewhat different views of how the overall AMI outsourced services would be provided. However, in the preliminary analysis each has been normalized to allow a similar "apples-to-apples" comparison. Based on the financial comparisons, the scope of services does not provide the traditional outsourcing value of reduced expense. The scope of AMI does not provide the typical services where outsourcing can leverage resources and provide lower costs. Outsourcing of AMI does not present the opportunity to consolidate the labor force, leverage existing services, or purchase products at significantly reduced rates.

a) Installation and Start-up

AMI deployment is a complex project and as such, every facet has significant risk associated with it. The financing of the meter assets and associated hardware components appears to have lower cost through SCE's cost of capital or financing rate. All of the integrated solution providers proposed that SCE should finance the meters, given that SCE's cost of capital appears lower than the providers' rates.

In all cases, the integrated solution providers included a partnership with a meter manufacturer as part of their solution. Again in all cases, the integrated solutions providers intended to complete the installations with contract labor. This use of contract labor would need further investigation regarding any additional costs that would be required as a result of potential labor union issues.

Meter testing assumptions varied by integrated solutions provider. The testing rate would need to be adjusted to meet the required service. This has potential pricing impact, but cannot be estimated until the exact meter manufacturer is chosen and a commitment to a specific defect level is achieved.

The initial deployment requires an inventory and distribution system that can handle approximately five million meters. Ongoing support of the infrastructure requires access by the provider into SCE's customer information system for customer data. SCE would be required to perform the majority of the estimated "back-office" IT application upgrades (*e.g.,* billing, contact center, *etc.*) regardless of the decision on outsourcing. The exact cost of the interfaces has not been estimated, but the view is that with advanced technology, there will be some cost to move data from the provider to SCE and visa versa.

The assessment of our preliminary outsourcing analysis indicates that from a cost perspective, the utility implemented scenario would be less expensive. The outsourcing scenario also adds a governance cost into the total cost. Given these results, it does not appear that outsourcing provides any financial benefits superior to the utility-implemented business case scenario for start-up and implementation.

b) Operations & Maintenance

On-going operations and maintenance for the full-scope deployment scenario includes the O&M of the existing meters during the five-year deployment phase (with inherent ramp down with the AMI rollout) and O&M of the new meters during the deployment phase (with inherent ramp up with the AMI rollout) and beyond. The responses from the integrated solutions providers included all functions up to and including delivering valid meter data to the billing function (with validation limited to reasonableness).

Determination of the treatment and transition of staff to a service provider were dealt with only at a high level for this analysis. There are issues related to union participation, severance, attrition, and training that would have an impact on the ongoing O&M function and cost. The three integrated solution providers provided solution descriptions that, at a high level, appeared to meet the requirements. Additional analysis would be required to ensure work flows, hand offs and responsibilities, and systems needs were fully defined.

Given these results, it appears that utility-implemented O&M provides financial benefits superior to outsourcing.

c) <u>Retained Responsibilities and Governance</u>

Governance and relationship management costs were estimated at 1% of the service provider estimated fee. This cost represents an oversight to ensure that the performed functions and products meet the requirements and continue to comply with all regulations. Retained responsibilities were identified for the meter functions (currently within our MSO, FSMRO, and TDBU Rurals organizations). These functions primarily would represent service delivery oversight, planning, design, customer relations, and other strategic functions. Finally, the miscellaneous implementation and operation responsibilities that were considered out of scope for our outsourcing analysis are identified as a retained function and cost.

C. <u>Scenario 3: Operational Plus Demand Response - TOU Default With Opt-Out</u>

Scenario 3 adds a Demand Response element to the full operational deployment of AMI. Not only do we include the costs associated with full operational deployment of AMI as presented in Scenario 1, but we have added the costs associated with placing and keeping a minimum of eighty percent of the AMI metered customers on TOU rates, with no more than twenty percent "opting-out" to their current rate or CPP-F rate. As was the case with Scenario 1, all costs and benefits included in the analysis of this scenario were estimated relative to the "Business As Usual" case. Table 3-14 summarizes the overall pre-tax costs and benefits of Scenario 3, and compares these costs and benefits to Scenario 1. Also shown is the after-tax NPV for these scenarios on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period.

Table 3-14
Scenario 3 Costs and Benefits Compared to Scenario 1
(2004 Present Value in Millions of Dollars)

	Scenario 1	Scenario 3	Difference
Cost	$986.7	$1,327.2	$340.5
Benefits	$341.5	$564.8	$223.3
Pre-Tax PV	($645.2)	($762.4)	($117.2)
After-Tax NPV	($446.6)	($520.1)	($73.5)
NPV of Rev Req	($1,120.0)	($1,244.3)	($124.3)

Scenario 3 derives all the operational benefits previously discussed in Scenario 1 above plus approximately $216 million in demand response benefits resulting from energy and demand reduction savings attributable to TOU rates.[33] Another $7 million in benefits will result from the availability of interval load data which will provide improved energy supply forecasting techniques ($3 million), and vastly increase the availability of Web based customer usage data ($4 million). These added benefits are offset, however, by added costs of more than $340 million, $192 million (or fifty-six percent) of which is due to a customer communications

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[33] Demand response is generally discussed in Volume 2, Section III and will be discussed specifically with respect to this scenario in Section 5(d) below.

campaign that would be required in order to achieve eighty percent acceptance of the default rate and ten percent adoption of the CPP-F rate in this scenario. Another $67 million (or twenty percent) of the increase associated with going from the operational-only scenario (Scenario 1) to this demand response scenario is attributable to additional Information Technology costs. Billing costs increase by $53 million (or sixteen percent).

1. Overview of Cost Differences

a) Information Technology Costs

The added Information Technology costs relate to the processes required to aggregate, validate and create billing-determinate data from interval consumption data being retrieved daily from nearly five million meters.

b) Billing Costs

Additional billing related costs result primarily from additional exception processing brought about by the more complex time-differentiated rate structures being introduced to the mass customer population. Customers being placed on more complex time-of-use rate structures, especially on an opt-out basis are expected to initiate more billing inquiries; in addition, the opt-out feature of the TOU default rate will inevitably result in mid-cycle rate changes. Failed usage validations, questionable usage (rate applicability) or meter “mis-match” problems will also add to the number of billing exceptions under this scenario. All of these exceptions require manual intervention on the part of the Billing Organization.

c) Customer Communications Costs

By far, the single largest cost impacts attributable to the demand response objectives of this scenario will result from the massive Customer

Communications and Customer Education programs that will be needed in order to maintain an eighty percent rate of participation on the TOU default rate for this scenario. The anticipated mass market advertising and customer education campaigns that would be needed to meet these objectives are common to all of the full deployment demand response scenarios and were described previously in Volume 2.[34] The Customer Communications programs related to this Scenario are expected to add approximately $192 million in 2004 present value dollars to the project.

The costs associated with the addition of Demand Response options under the full deployment will differ based on the scenario, but the basic structure and approach to the media and information delivery campaign will be similar. The strategic approach of the campaign is to utilize an integrated mix of media designed to affect a long-term cultural and behavioral change. The campaign must be multi-year in order to positively affect long-term change. There are three tenants of the campaign: 1) raise awareness and educate customers about the program and its benefits as well as the behavioral changes required to comply with each specific demand response option, 2) develop and implement a strong and comprehensive acquisition effort to recruit customers and meet participation rate expectations, 3) develop and implement a vigorous retention campaign to maintain the customer base over time. For this TOU "opt-out" scenario the following media will be employed:

- Mass Media: Television, radio, and print for education and awareness;
- Targeted/Ethnic Media: Local print, cable television, and strategic partnerships (ethnic business chamber promotion)

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[34] *See* Volume 2, Section III.

- including the use of in-language media for education and awareness; and
- Direct Communications: Bill inserts, direct mail, e-mail notification, voice mail notification, newsletters, face-to-face communication through the account management function for acquisition and retention.

Our Customer communications and outreach program is designed to reach 100 percent of our customers, and saturate the customer base with broad-based educational materials and information on customer-specific behavioral modifications.

d) Call Center Costs

We anticipate that the Call Center will be the central point of contact for customers wanting answers to their questions regarding the meter change process, rate changes, and "opt-out" procedures. For Scenario 3, we are estimating an increase in call volume of approximately 425,000 calls per year during the peak installation phase. This increased call volume will add a total of approximately $17.5 million to Call Center costs over the duration of the analysis period through 2021.

e) Management and Miscellaneous Other

The Management and "Other" cost categories make up $74.5 million of the $340.5 million in incremental cost differences between Scenario 1 and Scenario 3. The majority of this increase is attributable to $64 million of the $192 million Marketing and Customer Communications expenditures which were discussed earlier in this Section. By definition, a significant proportion of customer communications and marketing costs fall into this cost category, thus causing customer communication and marketing costs to be split between two cost codes:

CU-10 “Out-bound Communications (mass media costs, *e.g.*, print, radio, TV)”, and cost code M-14 “customer acquisition and marketing costs for new tariffs”. The remainder of the management and miscellaneous cost increases for Scenario 3 are described in the following sections.

2. Costs by Cost Code

Table 3-15 below summarizes the Scenario 1 vs. Scenario 3 costs by cost category.

Table 3-15
Summary of Costs for Scenario 3 vs. Scenario 1
(000s in 2004 Pre-Tax Present Value Dollars)

Cost Categories	Scenario 1	Scenario 3	Difference
Metering System Infrastructure*	$754,744	$755,299	$555
Communications Infrastructure	44,446	47,734	3,289
Information Technology Infrastructure	128,530	237,931	109,401
Customer Service Systems	39,745	192,440	152,695
Management and Miscellaneous Other	19,258	93,779	74,520
TOTAL:	$986,723	$1,327,183	$340,460

*Includes FSMRO SB-1 Severance Cost Offset

a) Meter System Installation and Maintenance

(1) Start-up and design

Appendix A to the Ruling does not identify any cost categories for meter system start-up or design. As such, any start-up or design activities have been classified as an installation cost below.

(2) Installation and Maintenance [MS-1 through MS-11]

For this scenario, the descriptions of activities and the associated costs for these cost categories are identical to those described in Scenario 1.

(3) Operation and Maintenance [MS-12 through MS-14]

When comparing the cost estimates for Scenarios 1 and 3, the cost difference can be attributed to changes in the labor costs associated with our Billing organization, which are being charged to cost category MS-12. As with Scenario 1, we anticipate that new issues will develop as a result of the implementation of new systems and the large number of meter changes. However, we anticipate that these issues will be more extensive given the introduction of new tariffed rate schedules to facilitate customers' demand response. We have estimated that additional personnel will be required in the initial phases of the implementation. As such, the labor costs for this area are estimated to increase by $0.55 million to $1.3 million over the 2006 to 2021 timeframe. The labor and non-labor costs of $42.1 million that are charged to MS-12 to support meter replacement and revenue protection activities are estimated to remain the same in this scenario as in Scenario 1. The descriptions of activities and the associated costs for cost categories MS-13 and MS-14 are the same as those described in Scenario 1.

b) Communications Infrastructure

(1) Start-up and design [C-1 through C-5]

In Scenario 3, the descriptions of activities and the associated costs for cost categories C-1, C-2, C-3 and C-4 are the same as those described in Scenario 1. However, there are changes in the costs related to cost category C-5. As discussed in Scenario 1, cost category C-5 captures the costs related to determining the appropriate IT application solutions to retrieve and process meter data. As discussed in further detail below, we will need to enhance additional applications in order to facilitate demand response capabilities in our systems. Given the additional applications that we are enhancing, we expect that the contractor costs associated with IT application solution design will increase from $0.20 million to $0.37 million.

Our Billing Organization will continue to partner with our IT organization in determining strategies for data retrieval and processing. They will assist IT in determining the system requirements needed to prepare and deliver accurate bills in a timely manner to those customers with AMI meters. Given the additional applications that we are enhancing, we expect that the project management and business analyst support labor costs associated with these activities will also increase. In addition, our Billing Organization will need to dedicate personnel to determine how its processes will be modified in order to accommodate the additional work that will be generated due to accounts failing system validations for usage-related reasons. We have estimated an increase from $0.18 million in Scenario 1 to $1.2 million in Scenario 3.

(2) <u>Installation [C-6 through C-11]</u>

In the installation area, there are two main differences between the Scenario 1 and Scenario 3 cost calculations. First, in Scenario 1, we did not have any incremental costs associated with cost category C-8. In Scenario 3, we will incur charges related to this cost category for Digital Signal Level 3 (DS3) costs. A DS3 is a high capacity telecommunication circuit. We plan to install two DS3s, one in our Rosemead facility and the other in our Irvine Operations Center to accommodate the additional traffic that is expected on our website. The bulk of the non-labor costs are associated with the leasing costs that we will incur from the telecommunication provider. We will also incur contractor costs in 2006, 2011, 2016 and 2021 associated with the installation and replacement of the equipment discussed in cost category C-10. Overall, the cost is estimated to be $1.9 million over the 2006 to 2021 timeframe.

Second, we also have differences in the costs associated with cost category C-10. In this scenario, we will continue to incur the $13.7 million in costs for the communications infrastructure hardware and equipment over the 2006 to 2010 timeframe that were discussed in Scenario 1. In addition, we will need to procure communication equipment that will link SCE's network to the DS3s discussed above. This equipment will be installed in 2006 and will need to be refreshed every five years. The cost associated with this equipment is $0.16 million over the 2006 to 2021 timeframe.

(3) Operation and Maintenance [C-12 through C-15]

In Scenario 3, the descriptions of activities and the associated costs for cost categories C-11, C-13, C-14 and C-15 are the same as those described in Scenario 1. The changes are related to cost category C-12. In Scenario 1, we did not have any charges associated with this cost category. However, in Scenario 3, cost category C-12 is used to capture the costs associated with various development tools licenses and fees. Non-labor costs of $49,700 are being charged to this cost category over the 2006 to 2007 timeframe.

c) Information Technology Infrastructure Costs

The information technology and application cost category captures the costs associated with applications and computer services. In addition to the costs incurred for the full deployment operational case, we will incur additional charges when demand response rates are introduced.

(1) Applications

In the Scenario 1 discussion, we described the various applications that would need to be developed and/or enhanced. For Scenario 3, these same applications would be required. In addition, enhancements would be required to our Service Billing, Usage Calculation, Wholesale Settlement and SCE.com systems. The discussion that follows provides a brief description of enhancements to these systems.

(2) Service Billing

Enhancements will need to be made to our Service Billing system, which provides the core functionality to calculate customer bills. The terms of each of the tariffed rate schedules are translated into "service plans" and stored within the Service Billing system. A service plan defines the types and levels of charges and specifies how a billing statement will be calculated for a service account. In Scenario 3, new tariffed rate schedules will be introduced. As a result, changes will need to be made to the Service Billing system to include the resulting service plans so that billing statements can be calculated.

(3) Usage Calculation

A core system functionality that will be needed to support AMI involves the processing of interval data. Currently, we have a fairly small-scale system, called the Customer Data Acquisition system, which handles calculating usage for existing customers with interval meter data. In this scenario, we will need to develop a new Usage Calculation system in order to handle the large volume of interval data that will be associated with the full deployment of AMI. As demand, energy, and power factor data are collected from meters, it will be transferred to the Usage Calculation system. The data will then be aggregated into values corresponding to the applicable season and time periods dictated by the terms of the service plan. Once aggregated, this data is transmitted to the Service Billing system for bill calculation and to the Wholesale Settlement system for financial settlement.

(4) Wholesale Settlement

Significant enhancements will need to be made to the Wholesale Settlement system. This system handles calculating various settlement charges related to power procurement activities with the California ISO and other counterparties. In the current system, the hourly usage values that are used to determine these settlement charges are calculated using load profiles, which are applied to monthly reads. Once demand response tariffed rate schedules are introduced, the usage data received for wholesale settlement will be actual interval usage data, replacing the use of load profiles. As such, the Wholesale Settlement system will need to be enhanced to handle the aggregation of the increased volume of actual interval usage data associated with the nearly 5 million AMI meters. The data needs to be aggregated by customer class and associated with the appropriate generation schedule and generation resource usage data in order to calculate settlement charges.

(5) SCE.com

Significant enhancements will need to be made to SCE.com in order to facilitate customers' participation in demand response programs as well as accommodate the expected increase in customer access. Currently, SCE.com provides customers with their monthly energy usage data and corresponding monthly costs. In terms of additional functionality for the user that will be developed, residential customers will have the ability to view their hourly energy usage data from the previous day while commercial and industrial customers will be able to view fifteen-minute data from the previous day. Customers will have access to available interval data for up to thirteen months and will be able to view charts and graphs for comparing applicable data. Customers will also be able to access analytical tools to manage energy usage and control costs. Customers will be able to view and monitor CPP rates and event details.

A key assumption driving the cost of these enhancements is related to the increased traffic expected on SCE.com. During non-critical event peak hours, we expect a ten percent increase in access over what we are experiencing today. However, during critical event peak hours, we expect that increase to jump to 110 percent. This increase is based upon 9,000 users accessing SCE.com during any given critical peak hour and approximately twenty percent of those users accessing the system concurrently.

d) Information Technology Costs by Category

(1) Start-up and design [I-1]

For this scenario, the description of activities and the associated costs for this cost category are the same as described in Scenario 1.

(2) Installation [I-2 through I-7]

(a) Computer System Set-up (I-2)

Our computing systems capacity will need to be increased in order to support AMI. As previously discussed, we will develop new applications and enhance existing applications. In Scenario 3, we are developing and enhancing additional applications to process the extensive volume of interval data that will be collected from meters to facilitate time differentiated billing. We are also enhancing SCE.com, our primary customer interface system. As compared to Scenario 1, in Scenario 3, we will need to procure additional hardware, storage, and operating software, including sixty additional processors and an additional 1,275 Gb storage, to supplement the computing infrastructure designed for Scenario 1. Given the data processing requirements of the demand response scenario, we will also need to increase the mainframe resources by 1,025 additional MIPS and 1,379 Gb in additional storage.

Another major cost driver in this cost category is related to customer bill printing. As new rate schedules are introduced to facilitate customers' demand response, we are expecting that the number of pages of our customer bill will increase from four to six. In order to control postage cost increases, we will need to maintain the current number of pages by printing on both the front and back of the bill stock. Our current printers do not accommodate printing bills in this manner. As such, new duplex printers will be required to process these new six-page bills.

In Scenario 3, to facilitate demand response, we will be posting a customer's usage data on SCE.com, as discussed in further detail below. Upgrades will need to be made to the SCE.com servers in order to accommodate additional customers accessing our webpage.

In Scenario 1, the cost associated with our computing systems upgrades was estimated to be $12.2 million, which would be incurred in 2006. In Scenario 3, the costs are more extensive, estimated at $43.4 million over the 2006 to 2021 timeframe.

(b) Data Center Facilities (I-3)

In Scenario 1, we did not have any incremental costs associated with cost category I-3. As discussed in cost category I-2, we will be procuring duplex printers. Due to the size of the duplex printers, we will need to incur additional charges related to facility modifications. Non-labor costs of $92,500 are being charged to this cost category in 2006.

(c) Develop/Process Rates in CIS (I-4)

As discussed in Scenario 1, a critical element of our IT application development efforts involves verifying that the new applications or enhancements do not adversely affect existing systems that process meter changes and meter reads and calculate bills. To ensure there are no adverse impacts, we will employ comprehensive testing techniques, such as regression, integration, unit and system testing. Since we are introducing more extensive application changes in Scenario 3, we will need to dedicate additional contractor resources to handle the testing activities. As such, we estimate the cost for these activities to increase from $24,940 to $221,710.

(d) New Information Management Software Applications (I-5)

As described above, we will need to significantly enhance our Wholesale Settlement system. The costs associated with developing the system requirements and database schema for this system are captured in this cost category. In addition, with the introduction of additional applications in Scenario 3, we will need to engage additional contractor resources to handle interface design and verification activities during the 2006 to 2007 timeframe. These activities are charged to various cost categories, including I-7 and I-8, depending upon the interface. The overall cost estimates for this cost category will increase from $13.6 million to $14.2 million.

Our Customer Service organization will partner with our IT organization in developing system and business requirements for the revisions that need to happen to SCE.com. They will also participate in testing the new website before it is launched for customer use. After the website is launched, they will identify system improvements to ensure that customers find the website easy to use. We have estimated $0.26 million in labor costs associated with these activities over the 2006 to 2010 timeframe.

(e) Records (I-6)

Additional applications will be developed and enhanced in Scenario 3, including Usage Calculation, Service Billing and SCE.com. The costs associated with developing the system requirements and database schema are captured in this cost category. Given these additional applications plus the extensive scope of the changes to them, we will need additional contractor resources to support these activities. We have estimated that the cost will increase from $0.53 million to $1.1 million in Scenario 3.

(f) Update Work Management Interface to Process Additional Meter Changes (I-7)

As detailed in the description for I-5, we will engage contractor resources to handle interface design and verification activities during 2006. In terms of the I-7 cost category, we estimate the cost for these activities will increase from $12,200 to $29,800.

(3) Operation and Maintenance [I-8 through I-16]

(a) Maintain Existing Hardware/Software that Translates Meter Reads into Bills (I-8)

As detailed in the description for I-5, we will engage contractor resources to handle interface design and verification activities during 2006. In terms of the I-8 cost category, we estimate the cost for these activities will increase from $20,500 to $177,400.

(b) Process Bill Determinant Data (I-9)

In Scenario 3, with the introduction of demand response rates, we will significantly increase the amount of usage data that is collected and processed. Instead of having one read and one time stamp per month for each account, we will have 720 reads and 720 time stamps per month. With this volume of data, we expect that there will be additional usage validation failures than what we are projecting in Scenario 1. As such, we will need additional customer service representatives to manually process the accounts that the system is unable to process. Our personnel estimates include costs for 18.3 FTEs in 2006, peaking at 101.3 FTEs in 2010, and tapering off to 89.5 FTEs for the 2011 to 2021 timeframe. Given the significant increase in personnel relative to Scenario 1, our cost estimates have increased from $20.5 million to $60.3 million.

In terms of our IT systems, we will also need to dedicate resources to defining additional rules that will determine whether data is processed by the system or whether it needs to be reviewed manually by a customer service representative. We will engage contractor resources to handle these activities during the 2006 to 2007 timeframe. We estimate the cost for these activities is expected to increase from $51,700 to $500,200.

(c) Contract Administration and Database Management (I-10)

As with Scenario 1, there are no incremental contract administration costs and the costs associated with infrastructure database management are included in I-16.

(d) Exception Processing (I-11)

As discussed in Scenario 1, our Billing Organization will continue to incur costs related to manual processing of accounts that fail billing system validations. In Scenario 3, with the introduction of new demand response rates, we expect that there will be additional exceptions that result during the billing process due to the significant amount of data that will be processed in order to calculate a bill. We will also be handling additional activities associated with processing rate changes for customers who opt-out of their TOU default rate. As such, we expect to dedicate additional personnel to handle this manual processing. Our cost estimates indicate a $4.4 million difference between the costs in Scenarios 1 and 3.[35]

In support of our IT systems, we will need to dedicate additional personnel to defining and developing the process by which exceptions are handled. We estimate the cost for these activities will increase from $62,500 to $97,700.

(e) License/O&M Software Fees (I-12)

The descriptions of activities and the associated costs for these cost categories are the same as those described in Scenario 1.

(f) Ongoing Data Storage/Handling (I-13)

As with Scenario 1, the incremental costs associated with ongoing data storage and handling were charged to cost code I-16.

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[35] However, as noted in Scenario 1, there was an error with this calculation. The costs will be updated, as appropriate, in our final analysis.

(g) Ongoing IT Systems (I-14)

As discussed in Scenario 1, cost category I-14 captures the costs related to the ongoing O&M for applications support, security administration, database administration support, maintenance and enhancement activities associated with the portfolio of applications that have been developed or enhanced to support AMI. In Scenario 3, we are introducing significant application enhancements, particularly those associated with the Usage Calculation system, in order to process the extensive volume of interval data. As such, we will need to dedicate additional contract and SCE resources to support our portfolio. We have estimated that the labor and non-labor costs to perform these activities will increase from $8.4 million in Scenario 1 to $11.7 million in this scenario.

(h) Operating Costs (I-15)

The descriptions of activities and the associated costs for these cost categories are the same as those described in Scenario 1.

(i) Server Replacements (I-16)

We expect to replace the computing systems hardware identified in cost category I-2 on the basis of a five-year technology refresh cycle. As such, the hardware refresh would occur in 2011 and 2016. We did not include a final refresh in 2021 based on our assumption that the entire AMI system will be obsolete and need to be renewed with new technology and supporting infrastructure. Contractor resources and incremental SCE FTEs will need to be utilized to handle the design and installation of the new hardware. Incremental SCE labor costs for database management are also included in this cost category. Given that our computing systems are more extensive (as discussed in the description for cost category I-2) in this scenario than in Scenario 1, we will have more equipment subject to refresh in 2011 and 2016. As such, the costs for refreshing the computing systems and associated labor are estimated to increase from $18.5 million in Scenario 1 to $46.7 million in this scenario.

e) Customer Service Systems

(1) Start-up and design

Appendix A to the Ruling does not identify any cost categories for customer service systems start-up or design. As such, any start-up or design activities have been classified as an installation cost below.

(2) Installation [CU-1 through CU-4]

In the installation area, there is one significant difference between the Scenario 1 and Scenario 3 cost calculations.[36] In Scenario 3, there will be additional charges related to cost category CU-2 due to increased call volume in our Customer Communications organization. We expect to experience the same call volume level for mass communications and meter change letters in Scenario 3 as we did in Scenario 1. However, with the introduction of time-differentiated rate schedules to facilitate customers' demand response, there will be additional customer communications that will ultimately lead to additional call volume. First, we will send customers a communication notifying them that their rate will be changed to a TOU rate schedule. We estimate that five percent of customers will call when notified that their rate is being changed. The five percent estimate is based on our experience with other communications in which rate modifications are

[36] In this preliminary analysis, there is a $2.3 million difference in cost category CU-1 between Scenarios 1 and 3. This is an error. In reality, the costs for this cost category will not change. This will be updated for the formal application, as appropriate.

included. Second, there will be customer calls related to opting out of the new rate. Our estimates assume twenty-seven percent of customers call about opting out and seventy percent of those that call actually chose to opt-out. Overall, for this cost code we are expecting to increase the call volume from 0.2 million in Scenario 1 to 0.6 million calls in Scenario 3. This results in a cost increase of $13.6 million comparing Scenario 1 costs to Scenario 3 costs.

(3) Operation and Maintenance [CU-5 through CU-10]

As discussed previously, the most significant cost difference in the operation and maintenance area between Scenarios 1 and 3 is related to the marketing costs, a portion of which are charged to cost category CU-10. The Customer Communications programs related to this scenario are expected to add a total of approximately $128 million in costs. Another $64 million in Customer Communications and Marketing costs related to this Scenario are, by definition included in cost code M-14 ("Customer Acquisition and marketing costs for new tariffs". These will be described below in the "Management and Miscellaneous Other" cost category.

In Scenario 3, beginning in 2007, the Call Center expects to receive customer calls related to their first series of bills after changing rates. We projected that our customers would go through a learning curve period in which a declining percentage of customers would call after each bill is received after switching to the new rate. For Scenario 3, these rate-related calls are expected to increase call volume by 100,000 to 150,000 calls per year at an added cost in cost code CU-8 of $2.5 million. We also expect to receive approximately 10,000 additional calls annually from customers with questions related to their first review of usage data presented on SCE.com. As previously discussed, we projected that our customers would go through a learning curve period in which a declining percentage of customers would call after each session on SCE.com to review usage data. The total costs over the analysis period associated with these additional calls, which are charged to cost category CU-9, are estimated to be $212,000.

As new rates are introduced in Scenario 3, we expect to experience an increase in the number of customer requests for rate analysis. These requests are expected to impact not only our Billing Organization, but our Major Customer Division (MCD) as well. MCD provides coordination between account representatives and major customers for rate analysis opt-out and contract revisions. Customers who are deciding whether to opt out may want to request a rate analysis to determine if the rate assigned to them is the best rate to stay on. Customers who decide to opt-out of the rate may want to request a rate analysis to determine a more appropriate rate. The total increased cost for both Billing and MCD associated with these activities is expected to be $2.7 million in cost code CU-5.

We will also incur some relatively minor costs of $0.1 million in cost category CU-8 related to developing materials for our customer account representatives and major customers.

In Scenario 3, our Customer Service organization will incur costs related to the development of market research surveys to learn about customers' wants and needs so that the information learned can be applied to enhance the website. Costs will also be incurred related to assisting major customers in learning to how to use the website and access their usage data. We will also provide support to the Customer Communications organization by handling customer telephone calls regarding complex website related questions. The costs for these activities, which will be charged to cost categories CU-8 and CU-9, are estimated to be $7.6 million. These web-based costs include the total cost of replacing the existing systems and we have identified over $4 million in offsetting benefits, which are included in benefit codes CB-8 and MB-1.

f) Management and Miscellaneous Other

The Management and Miscellaneous cost categories make up $74.5 million of the $340.5 million in incremental cost differences between Scenario 1 and Scenario 3. The majority of this increase is attributable to the $64 million in Marketing and Customer Communications expenditures needed to retain 80% of the AMI metered customers on TOU rates, given that they will have the option of opting-out either to return to their otherwise applicable tiered rate or to move to an optional CPP rate. The $64 million in marketing costs assigned to this cost category is in addition to the $128 million described previously for this scenario in cost code CU-10. The remainder of the management and miscellaneous cost increases for Scenario 3 are described in the following sections.

(1) Start-up and design [M-1 through M-2]

These two cost codes relate to meter installations and were addressed in the Operational-only scenario. No additional costs would be incurred in this demand response scenario.

(2) Installation [M-3 through M-11]

Five of these Management cost codes (M-3, M-6, M-8, M-9 and M-11) were described in Scenario 1 above with no incremental increases for the demand response scenarios.

(a) Employee Communications and Change Management (M-4)

We estimated $104,000 in additional cost related to all demand response scenarios over the duration of the analysis period for Web related costs associated with employee communications.

(b) Employee Training for New Systems and Rate Structures Etc. (M-5)

Employee communication programs on the Web will add $396,000 to this cost code for all demand response scenarios. This will supplement the Billing Organization and JST training described in Scenario 1 under this cost code, and it relates primarily to assuring that customer contact personnel have a clear understanding of the rates and rate options being introduced under this scenario.

(c) Project Management Costs and Overhead (M-7)

The Billing Organization, Call Center and IT combined will have approximately $7 million in management and overhead cost increases under this scenario. This is for indirect management and supervision activities related to the increases in personnel for the functions described previously in the Information Technology (I-1 through I-16) and Customer Services (CU-1 through CU-10) cost codes.

(d) Call Center Training Costs (M-10)

The Call Center would incur $780,000 in additional cost for specialized training to be able to respond to the large anticipated call volume brought about by the opt-out provisions of the TOU default rate. This is in addition to the "Customer Services" cost impacts discussed previously under cost codes CU-2, CU-8, and CU-9 above.

(3) Operation and Maintenance Costs (M-12 through M-15)

Our capital financing costs are included within the Meter Acquisition costs described previously, and we did not use the M-12 cost code to include any additional or alternative financing costs. Nor have we identified any cost for increased load during mid-peak and off-peak periods (M-13).

(a) Customer Acquisition and Marketing Costs for New Tariffs (M-14)

Incremental customer acquisition and marketing costs in this cost code combined with the marketing costs described in cost code CU-10 above make up the total customer communications program. This cost code includes $64 million of the $192 million to be spent on customer acquisition and customer education programs that will be necessary to secure eighty percent of the AMI metered customers on TOU rates, and keep them there for the duration of the analysis period.

(b) Risk Contingencies (M-15)

The Energy Supply and Marketing Organization has included $2.3 million in added "risk management" cost for their Load Forecasting group to support the analysis and more complex modeling that will result from the availability of real-time data after AMI implementation. The group will query a ninety percent plus sample of real-time, prior-day load data from end-use customers on a daily basis. The data will require "cleaning" and comparison to prior month Settlement data to estimate the 100 percent bundled load per hour for the previous day. Additionally, to support trading, the Load Forecasting group will analyze the price vs. usage patterns by hour and by month to account for how customers will respond to post AMI conditions (compared to current, non-AMI conditions) and use this analysis to adjust the forecast one to five days in the future. Long-term forecasting will also be impacted by the availability of hourly / monthly sales data. The benefits expected to result from this process are discussed in the following section under benefit code SB-9.

3. Benefits

Estimated benefits for Scenario 1 and Scenario 3 are compared by benefit category in Table 3-16 below.

Table 3-16
Summary of Benefits for Scenario 3
(000s in 2004 Pre-Tax Present Value Dollars)

Benefit Categories	Scenario 1	Scenario 3	Difference
Systems Operations Benefits	$272,258	$275,481	$3,223
Customer Service Benefits	4,854	7,737	2,883
Management and Other Benefits	64,442	65,648	1,206
Demand Response Benefits		215,910	215,910
TOTAL:	$341,554	$564,776	$223,222

In addition to $216 million in demand response benefits described later in this section, we have recognized $1.2 million in equipment replacement benefits (MB-1), and an additional $2.9 million in operational cost offsets to accommodate those customers who are already on demand response rates or who otherwise use the web based programs for energy management information (CB-8).

Our Energy Supply and Marketing Organization has estimated $3.3 million in reduced resource acquisition costs in cost code SB-9. This is the result of improved long- and short-term forecasting attributable to improved modeling and analytical techniques using AMI data.

To determine the DR-1 benefit, we employ a complex method of computing demand response from TDRs, as described in detail in Section III.B of Volume 2. We apply our respective TDRs for this scenario for the tariff participation as discussed above and illustrated in Volume 2 (our TDR rates are described in Volume 2, Section III.C, and Appendix B, by class). We also use price elasticity data by rate and rate period derived in the SPP, adjusted for our climate and air conditioning saturation by climate zone. We employ a computer simulation model to estimate the load reductions by rate and period for the duration of the scenario and compute a present value using our assumed discount rate.

We treat that full demand reduction as a "load modifier" and value it in accordance with the capacity and energy assumptions provided in the ACR for DR-1 benefits. In the Ruling's required scenarios, we estimate the demand reduction from TDRs using customer enrollment assumptions provided by the ACR and customer response as was observed in the SPP experiment in summer 2003. Also, in the Ruling's required scenarios, since we reduce our expected load by the calculated demand reduction at peak, we also apply system reliability benefits (capacity buffer) (DR-2). The reduction in load from TDRs reduces the amount of capacity for which a reserve margin of fifteen percent would be procured. Therefore, system reliability (capacity buffer/DR-2) benefits were calculated as fifteen percent of TOU and CPP demand reductions only on CPP days. DR-2 benefits are additive to the DR-1 benefits calculated for each rate and scenario.

As described in Volume 2, Section III.B, we do not believe DR-3 or DR-4 benefits apply in any scenario.

The full deployment scenarios cover various Time Differentiated Rate (TDR) approaches to the population equipped with AMI, as required in the

ACR. Under full deployment of AMI, ninety percent of residential customers would be eligible for TDRs. Customer enrollment percentages per TDR are applied to the eligible population equipped with AMI. It is assumed that customers enrolled in any type of CPP rate will be fully aware of their rate mechanism and will be notified individually of CPP events. SCE also used the SPP results for enrollment and for demand response as the best available point estimates for business case purposes.

Scenario 3 assumes that eighty percent of eligible customers are defaulted to TOU rates and those customers stay on that rate for the full duration of the business case. For the purposes of the analysis, SCE assumed that the customers opting out of the default would either switch back to their tiered rate or choose a CPP-F rate in equal proportions. The total benefit is shown in Table 3-17.

Table 3-17
TOU Default with Opt-out to CPP-F or Current (Scenario 3)

	No. of Meters (Customers) Year 2021	Percent of Eligible Meters	Present Value ($ millions)
Meters Eligible for TDRs	5,114,245		
Customers Enrolled on TOU	4,091,396	80	$81
Customers Enrolled on CPP-F/V	511,424	10	$135
Customers Enrolled on Current	511,424	10	$0
Total DR-1 Benefits			$192
Total DR-2 Benefits			$24
Total DR Benefits			$216

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B. For this scenario, the Value of Service loss is approximately $100 million (2004 present value dollars), reducing the total demand response benefit from $216 to $116 million.

4. Uncertainty and Risk Analysis

For Scenario 3, the total present value cost estimate for full AMI deployment is $1.33 billion. We developed cost ranges as described in Section III.C.3 and applied a Monte Carlo statistical analysis of costs that resulted in a range of $1.313 billion to $1.476 billion around the estimated cost of $1.349 billion for this scenario. The statistical analysis indicates that our cost estimate has less than a ten percent confidence. This means that the project has a ninety percent chance of overrunning. Our preliminary cost estimates do not include contingency. However, based on our analysis we should consider a contingency of approximately $80 million in our final application to reduce the risk of overrun. This contingency amount is the difference between our cost estimate and the value at the ninety percent confidence level.

Risks and uncertainties for the demand response are generally discussed in Volume 2, Sections III and IV. However, there are certain risks and uncertainties applicable to Scenario 3. First, opt out or default customer enrollment on TOU rates likely has the greatest chance of success of any TDR approach since it would be less “invasive” to customers than CPP and similar to peak pricing in other industries such as telephones. Thus, in our view, it is more likely that TOU would achieve significant and sustained customer participation. Since customers would not have to be notified of CPP events, they could remain less aware of their rate structure and a higher percentage of customers may remain on a TOU rate over time than if they had higher awareness, according to market research in SPP. However, an assumption of higher participation in TOU, (ninety percent rather than eighty percent), and less participation in CPP-F (five percent rather than ten percent) would yield lower demand reductions than Scenario 3 because the elasticity assumptions for CPP-F are more than double that of TOU. In Scenario 9 below, we examine the effects of fifty percent participation on TOU.

SCE believes that the result for DR-1 benefits in this scenario could be less than estimated because the customers opting-out from TOU to a CPP-F rate would likely be those who benefit by making no adjustment in usage, therefore providing less demand response benefit for that rate group. This is because, for lack of better information, the demand response behavior of CPP-F customers in this scenario is assumed to be the same as the behavior of customers in the SPP experiment. In the SPP, it is unclear whether customers opted-in to the experiment where they were paid an incentive of $175 to participate. Customers on CPP-F rates apparently changed behavior but it is unknown whether this was due to the rate or the incentive payment.

If DR-1 benefits are smaller, the DR-2 benefits would decrease proportionately.

5. Net Present Value Analysis

Table 3-18 summarizes the overall pre-tax costs and benefits of Scenario 3. Also shown is the after-tax NPV for this scenario on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period..

Table 3-18 Summary of Cost/Benefit Analysis for Scenario 3 ($ Millions)				
Costs	**Benefits**	**Pre-tax Present Value**	**After-Tax NPV**	**Rev. Req. Present Value**
$1,327.2	$564.8	($762.4)	($520.1)	($1,244.3)

As shown in Table 3-18 above, Scenario 3 analysis results in a negative Revenue Requirement present Value of $1,244.3 million and does not support the implementation of full AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the scenario 3 analysis, plus the recovery of SCE's net investment in any removed meters, plus the rate of return and tax impacts of the AMI-related investments.

D. Scenario 4: Operational Plus Demand Response - CPP-F/CPP-V Default with Opt-Out

Similar to Scenario 3 above, Scenario 4 assumes full deployment of AMI meters to 90% of all SCE customers. The only difference between Scenario 3 and Scenario 4 is that the default rate in this scenario is CPP-F for residential customers and CPP-V for C & I customers (TOU was the default rate for all customers in Scenario 3). The only cost difference between Scenario 3 and Scenario 4 is in the Marketing and Customer Communications programs, where we would expect to spend approximately $21.6 million more in cost code CU-10 for CPP event notification costs over the duration of the analysis period. This notification requirement is expected to add approximately $1 million to $3 million annually to the total program cost depending on the number of CPP events. For our purposes in this analysis, we have assumed fifteen CPP events per year. This is consistent with the number being used in the Statewide Pricing Pilot (SPP). There are no other assumed operational cost differences between this scenario and those presented earlier in the Scenario 3 analysis.

Table 3-19 summarizes the costs and benefits for Scenarios 3 and 4.

Table 3-19
Scenario 4 Costs and Benefits Compared to Scenario 3
(In Millions of 2004 Present Value Dollars)

	Scenario 3	Scenario 4	Difference
Cost	$1,327.2	$1,348.8	$21.6
Benefits	$564.8	$1,008.0	$443.2
Pre-Tax PV	($762.4)	($340.8)	$421.6

Scenario 4 derives all the operational benefits previously discussed in Scenario 3 above plus approximately $443.2 million in demand response benefits resulting from energy and demand reduction savings attributable to increased customer participation on CPP rates.

1. Costs

Table 3-20 below summarizes the costs by cost category for Scenario 4 vs. Scenario 3.

Table 3-20
Summary of Costs for Scenario 4
(000s in 2004 Pre-Tax Present Value Dollars)

Cost Categories	Scenario 3	Scenario 4	Difference
Metering System Infrastructure	$755,299	$755,299	$-0-
Communications Infrastructure	47,734	47,734	-0-
Information Technology Infrastructure	237,931	237,931	-0-
Customer Service Systems	192,440	214,069	21,629
Management and Miscellaneous Other	93,779	93,779	-0-
TOTAL:	$1,327,183	$1,348,811	$21,629

Other than the $21.6 million additional cost related to notifying customers in advance of CPP events, all other Customer Communications and Marketing programs that will be needed to maintain an eighty percent rate of participation on the CPP default rates are the same as those described for Scenario 3. Proactive notification will be provided to those customers who subscribe to the "Envoy" service administered by SCE. The proactive notification consists of a single courtesy call via telephone, fax, page, or email that will be placed to the number/device ID provided by and maintained by the customer. The notification message content will include event date, time, and duration. If the customer selects to be notified via telephone, the event information will be conveyed through a pre-recorded thirty-second message. Customers will not be charged for this service but must initiate and maintain their enrollment in order to participate. Absent such customer designation of contact information, SCE will not proactively or individually notify other default CPP participants.

Costs related to CPP event notification were calculated directly as a function of the number of customers expected to participate on the CPP tariff over the duration of the analysis period. For Scenario 3 we estimated 450,000 to 500,000 sustained CPP participants; whereas, for Scenario 4 we estimated approximately four million participants.

2. Benefits

Scenario 4 benefits are summarized below in Table 3-21. These benefits are the same as those described previously for Scenario 3, except the demand response benefits are expected to increase by $443 million (going from $216 million in Scenario 3 to $659 million in Scenario 4). The reason for the much higher benefit is that customers on CPP rates demonstrated a higher price elasticity on CPP rates than TOU. As previously noted, the SPP experiment did not find statistically significant price responsiveness for customers on TOU rates. Therefore, the price elasticity for the TOU portion of the CPP rate on non-CPP days was used as a proxy. The price elasticity differences for CPP-F compared to TOU by climate zone and rate class are shown in Volume 2, Section III.

Table 3-21
Summary of Benefits for Scenario 4 vs. Scenario 3
(000s in 2004 Pre-Tax Present Value Dollars)

Benefit Categories	Scenario 3	Scenario 4
Systems Operations Benefits	$275,481	$275,481
Customer Service Benefits	7,737	7,737
Management and Other Benefits	65,648	65,648
Demand Response Benefits	215,910	659,173
TOTAL:	$564,776	$1,008,039

This scenario assumes that eighty percent of eligible customers are defaulted to CPP-F rates (residential) or CPP-V rates (commercial <200 kW) and those customers stay on those rates for the full duration of the business case. For the purposes of the analysis, SCE assumed that the customers opting-out of the default would either switch back to their tiered rate or choose a TOU rate in equal proportions. The total benefit is estimated to be $1,008 million in present value as shown in Table 3-21.

Table 3-22 CPP-F/V Default with Opt-out to TOU or Current (Scenario 4)			
	No. of Meters (Customers) Year 2021	**Percent of Eligible Meters**	**Present Value ($ millions)**
Meters Eligible for TDRs	5,114,245		
Customers Enrolled on CPP-F/V	4,091,396	80	$643
Customers Enrolled on TOU	511,424	10	$17
Customers Enrolled on Current	511,424	10	$0
Total DR-1 Benefits			$580
Total DR-2 Benefits			$79
Total DR Benefits			$659

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B. For this scenario, the Value of Service loss is approximately $340 million (2004 present value dollars), reducing the total demand response benefit from $659 to $319 million.

3. Uncertainty and Risk Analysis

Scenario 4 costs and operational benefit risks and analysis results are essentially the same as described previously in Scenario 3.

We believe that this scenario is implausible for a number of reasons. First, we believe that it is unlikely that CPP rates would be imposed on the mass market without first testing customer acceptance of TOU rates over many years.

Next, we believe that even if default enrollment of CPP was implemented, it is highly unlikely that eighty percent of customers would adopt the CPP rate over the entire sixteen-year study period. The SPP found that four to six percent of customers chose to drop the CPP-F rate after the first year of the experiment despite an offering of incentive payments to continue participation in the program in 2004. Moreover, a shadow-bill analysis of SPP CPP-F customers found that 26.3 percent actually had higher bills than they would have if they had stayed on their otherwise applicable rate. Over time, customers who experience higher bills will likely opt out to a more favorable rate. We provide an alternative analysis of this scenario using sustained participation rates of fifty percent for CPP in Scenario 10 below.

Another key but unlikely assumption is that all eighty percent of customers on CPP-F and V would respond over the sixteen-year period at the same level as customers in the SPP experiment. As noted above, the SPP experiment offered customers a $175 incentive for their participation in 2003. These customers were opt-in (affirmative enrollment) rather than default enrollments. Even though we include significant expenses for customer education and awareness, as well as notification of CPP events, it is unlikely that the entire population that defaulted on to the rate on average would be as informed and as responsive as SPP customers. In Volume 2 of this filing, we described the above and other concerns and uncertainties associated with CPP rates as well as whether AB1-X would preclude a default implementation of CPP.

4. Net Present Value Analysis

Table 3-23 summarizes the overall pre-tax costs and benefits of Scenario 4. Also shown is the after-tax NPV for this scenario on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period.

Table 3-23 Summary of Cost/Benefit Analysis for Scenario 4 ($Millions)				
Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. Present Value
$1,348.8	$1,008.0	($340.8)	($269.5)	($822.9)

Scenario 4 analysis results in a negative Revenue Requirement Present Value of $822.9 million and does not support the implementation of full AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the Scenario 4 analysis, plus the recovery of SCE's net investment in any removed meters, plus the rate of return and tax impacts of the AMI-related investments.

E. Scenario 5 and Scenario 6: Operational Plus Demand Response - Current Tariff with Opt-in to CPP Pure (Scenario 5) and Opt-in to CPP-F and CPP-V (Scenario 6)

These two scenarios are prescribed in Attachment A of the Ruling as two of the five tariff structures to be analyzed in the full deployment case.[37] Both our Scenario 5 and Scenario 6 analyses assume the existing tariff structures will remain as the "default" tariff and customers will have the option of a CPP tariff. The only difference between Scenario 5 and Scenario 6 is that Scenario 5 offers the "CPP-Pure" rate option to all rate classes,[38] and Scenario 6 offers the "CPP-F" rate option to residential customers and the "CPP-V" rate option to C&I customers. From an operational standpoint, SCE assumes no difference in costs between Scenarios 5 and 6. The only difference between the scenarios is in the level of demand response benefits we would expect to receive between the two options.

For comparison purposes, we will describe the cost differences of these two scenarios relative to Scenario 4, which had CPP-F/V as the "default" tariff. Thus, the following incremental differences in costs and benefits reflect the savings we expect would result from making CPP "optional" rather than the "default" tariff. This difference significantly reduces the level of customer participation, thus reducing not only the cost, but the demand response we expect would result.

Table 3-24 compares the costs and benefits for Scenarios 5 and 6 to the costs and benefits we expect for Scenario 4 and Scenario 1.

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[37] Ruling, Attachment A, p. 11.

[38] The "CPP-Pure" rate does not exist today. All current CPP rates fall back onto a TOU rate for non-critical peak periods. "CPP-Pure" would be a newly adopted rate schedule that would fall-back on the customer's OAT for non-critical peak periods.

Table 3-24 Comparison of Costs, Benefits, and NPV for Scenarios 1, 4, 5 and 6 (Millions of 2004 Pre-Tax Present Value Dollars)				
	Scenario 1 Operational Only	**Scenario 4 OP + CPP Opt-out**	**Scenario 5 OP + CPP-Pure Opt-in**	**Scenario 6 OP + CPP-F/V Opt-in**
Costs	$986.7	$1,348.8	$1,265.9	$1,265.9
Benefits	$341.6	$1,008.0	$511.7	$508.6
Pre-Tax PV	($645.2)	($340.8)	($754.2)	($757.3)

1. Costs by Cost Code

This section will describe the differences between the incremental costs by cost code for Scenario 4 and the incremental costs for Scenarios 5 and 6. As Table 3-25 shows, the costs for Scenarios 5 and 6 are identical.

Table 3-25 Summary of Costs for Scenarios 4, 5 and 6 (000s in 2004 Pre-Tax Present Value Dollars)				
Cost Categories	**Scenario 4**	**Scenario 5**	**Scenario 6**	**Difference (4 v. 5 & 6)**
Metering System Infrastructure	$755,299	$755,299	$755,299	-0-
Communications Infrastructure	47,734	47,829	47,829	94
Information Technology Infrastructure	237,931	228,877	228,877	9,053
Customer Service Systems	214,069	183,737	183,737	30,332
Management and Miscellaneous Other	93,779	50,141	50,141	43,638
TOTAL:	$1,348,811	$1,265,882	$1,265,882	$82,929

a) Meter System Installation and Maintenance

For Scenarios 5 and 6, the costs are identical to those described in Scenario 4.

b) Communications Infrastructure

For Scenarios 5 and 6, there is only one cost difference relative to Scenario 4. In cost category C-5, the costs our Billing organization will incur are estimated to increase by approximately $94,000. We anticipate that we will need additional business analyst support in 2006.

c) Information Technology Infrastructure

In Scenarios 5 and 6, the cost differences relative to Scenario 4 are contained within two cost categories, I-9 and I-11. With the introduction of demand response rates, our Billing Organization will see an increase in the amount of usage data that is collected and processed. As discussed previously, we expect that there will be additional usage validation failures and billing validation failures in demand response scenarios than what we would see in operational-only scenarios. Additional customer service representatives are needed to manually process the accounts that the system is unable to process. The number of additional personnel that we need for this activity will vary between Scenarios 5 and 6 and Scenario 4. Our personnel estimates are driven by the number of customers on a rate requiring interval data. Since we anticipate a smaller number of customers will have rates requiring interval data in Scenarios 5 and 6, we anticipate that we will need less customer service representatives to handle this manual processing of accounts. For cost category I-9, we anticipate decreasing our cost estimate from $60.3 million in Scenario 4 to $56.1 million in Scenarios 5 and 6. For cost category I-11, our cost estimate decreases from $6.3 million in Scenario 4 to $1.6 million in Scenarios 5 and 6.

d) Customer Service Systems

Customer Service Systems costs are significantly lower for Scenarios 5 and 6 in two specific areas:

- Marketing and customer costs in cost code CU-10 will be $18.9 million lower for these scenarios than for Scenario 4. This is due to the expected smaller number of customer participants and the reduced call volume for proactive notification of CPP events to those customers who subscribe to the "Envoy" service administered by SCE.
- Call Center costs will be $9.3 million lower, due again to the lower number of active participants and lower anticipated call volume because there will be no "default" rate change notices and no "opt-out" provision under these scenarios. These costs are shown in cost code CU-2. Cost code CU-8

estimates for the Call Center are also lower for these two scenarios by $2.2 million. This is due to fewer calls expected during critical peak pricing events, and resultant bill impacts.

e) Management and Miscellaneous Other Costs

The Management and Other cost categories are $43.6 million lower for these two scenarios due primarily to $40.7 million less required for "customer acquisition and marketing" costs in cost code M-14. Project Management costs (cost code M-7) are also expected to be lower in the Call Center and Billing Organization by $2.5 million over the duration of the analysis period. Call Center training costs (cost code M-10) will also be lower by $468,000, again due to the lower anticipated call volume and less need to train new employees.

2. Benefits

As shown in Table 3-26 the benefits by category for Scenarios 4, 5 and 6 are identical except for the demand response benefits.

Table 3-26 Summary of Benefits for Scenarios 5 & 6 (000s in 2004 Pre-Tax Present Value Dollars)			
Benefit Categories	**Scenario 4**	**Scenario 5**	**Scenario 6**
Systems Operations Benefits*	$275,481	$275,481	$275,481
Customer Service Benefits*	7,737	7,737	7,737
Management and Other Benefits*	65,648	65,648	65,648
Demand Response Benefits	659,173	162,817	159,740
TOTAL:	$1,008,039	$511,683	$508,606

Scenario 5 assumes that twenty-two percent of AMI metered residential and C&I customers would opt in to the CPP-Pure rate and remain there until 2021. We used the Momentum Market Intelligence (MMI) model developed from customer survey data in the SPP to determine the customer enrollment percentage in the first year and used that same percentage for every year in the analysis.

Scenario 6 assumes that eleven percent of AMI metered residential customers would opt in to the CPP-F rate and eight percent of the metered C&I customers would opt in to the CPP-V rate and remain there until 2021, respectively. As in Scenario 5, we used the MMI model to determine customer enrollment percentage in the first year and used that same percentage for every year in the analysis.

Under Scenario 6, residential and small commercial/industrial customers below 200 kW could opt in to either a CPP-F or CPP-V rate. We used the MMI model to determine customer enrollment in CPP-F and CPP-V rates.

As described in Volume 2, the SPP experiment did not examine customer behavior to CPP-Pure rates so we used the price elasticity estimates for CPP-F from the SPP for CPP-Pure. Also, the SPP did not find statistically significant or representative C&I customer behavior to CPP-V rates. As a proxy, we used 25 percent of the residential price elasticity found for CPP-F for C&I, which is supported by the literature. Accordingly, the demand response for CPP-Pure is the same as for CPP-F, however, the enrollment to CPP-Pure versus CPP-F is slightly different due to differences in rate design and bill impacts.

The demand response benefits for Scenarios 5 and 6 are shown in Table 3-27 below.

Table 3-27 Demand Response Benefits for Scenario 5 (Current Default with Opt-in to CPP-Pure) and Scenario 6 (Current Default with Opt-in to CPP-F or CPP-V)				
	Scenario	**No. of Meters (Customers) Year 2021**	**Percent of Eligible Meters**	**Present Value ($ millions)**
Meters Eligible for TDRs	5	5,114,245		
Customers Enrolled on CPP-Pure	5	1,161,542	22	$163
Customers Enrolled on Tiered Rate	5	3,952,703	78	$0
Total DR-1 Benefits	5			$143
Total DR-2 Benefits	5			$20
Total DR Benefits Scenario 5	5			$163
Meters Eligible for TDRs	6	5,114,245		
Customers on CPP-F (Scenario 6)	6	612,944	11	$96
Customers on CPP-V (Scenario 6)	6	423,482	8	$65
Customers Enrolled on Tiered Rate	5	4,077,769	81	$0
Total DR-1 Benefits	6			$141
Total DR-2 Benefits	6			$19
Total DR Benefits Scenario 6	6			$160

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B.

For Scenario 5, the Value of Service loss is approximately $82 million ($2004 present value), reducing the total demand response benefit from $163 to $81 million. For Scenario 6, the Value of Service loss is approximately $82 million ($2004 present value), reducing the total demand response benefit from $160 to $78 million.

3. Uncertainty and Risk Analysis

Scenarios 5 and 6 costs and operational benefits risks and analysis results are essentially the same as described in Scenario 3.

With regard to the demand response uncertainty, we believe that using price elasticity for CPP-F as a proxy for CPP-Pure likely overstates the demand response for CPP-Pure because customers on CPP-F rates also have a TOU portion of the rates on non-CPP days, which encourages customers to make "permanent" adjustments to usage with programmable thermostats (not provided) or other behaviors. In contrast, CPP-Pure events would only happen twelve days during the summer.

4. Net Present Value Analysis

Table 3-28 summarizes the overall pre-tax costs and benefits of Scenarios 5 and 6. Also shown is the after-tax NPV for these scenarios on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period.

Table 3-28 Summary of Cost/Benefit Analysis for Scenarios 5 & 6 ($ Millions)					
Scenario	Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. Present Value
Scenario 5	$1,265.9	$511.7	($754.2)	($515.2)	($1,235.3)
Scenario 6	$1,265.9	$508.6	($757.3)	($517.0)	($1,238.4)

As shown in Table 3-28 above, our Scenario 5 analysis results in a negative Revenue Requirement present value of $1,235.3 million and our Scenario 6 analysis results in a negative Revenue Requirement present value of $1,238.4 million. Neither Scenario 5 nor Scenario 6 supports the implementation of full AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the Scenario 5 and 6 analyses, plus the recovery of SCE's net investment in any removed meters, plus the rate of return and tax impacts of the AMI-related investments.

F. Scenario 7: Operational Plus Demand Response Plus Reliability - CPP-F/CPP-V Default with Opt-Out

Scenario 7 is similar to Scenario 4 except that it adds a reliability element to the full operational deployment of AMI. The Ruling directs us to evaluate additional reliability benefits which we do by coupling the active use of load control technology. For the reliability component of this scenario, we have chosen the Advanced Load Control (ALC) program included as part of our Long-Term Procurement Plan (LTPP) and in our 2005 Demand Response Proposals which were filed on October 15, 2004.[39] This proposed ALC program is described in our

[39] SCE's (U-338-E) Demand Response Program Proposals for 2005-2008, in R. 04-04-003

Business As Usual Case as a planned upgrade to the existing systems that will be impacted by the potential deployment of AMI. As with Scenario 4, the assigned customer acceptance rate of the default tariffs (CPP-F for residential customers and CPP-V for C & I customers) in this scenario is eighty percent, with twenty percent opting-out to either TOU or their current tariff on an equal basis. As will be discussed in the next paragraph, the high participation rate on CPP results in a reduced participation on ALC, below that experienced in the Business As Usual case. Scenario 7 differs from Scenario 4 in that the costs and benefits of the ALC program are included in this scenario, whereas they were excluded in Scenario 4.

Since this scenario assumes that eighty percent of customers are on CPP rates, our ALC program and customer projections are necessarily "scaled back." This is because, as currently defined, customers cannot participate on both CPP and ALC at the same time. Independent of AMI, the ALC program is projected to enroll 500,000 customers. In this scenario with eighty percent CPP participation, we assume only 100,000 customers will participate given the CPP rates. Although this scenario includes the lower costs and benefits of the "scaled-back" load control program, by definition it does not incorporate the secondary (resource plan) impacts of those program reductions. We have, however, included these impacts in our preferred alternative analysis of this same default tariff in Scenario 11, along with what we believe to be a more reasonable customer participation rate of fifty percent. Scenario 8, to be presented in the next section, will reflect the costs and benefits of a less constrained ALC program by reducing the CPP participation assumption from eighty percent down to nearly twenty percent.

1. <u>Costs</u>

Table 3-29 summarizes the costs by category of Scenario 7 compared to those for Scenario 4.

Table 3-29 Summary of Costs for Scenario 7 vs. Scenario 4 (000s in 2004 Pre-Tax Present Value Dollars)			
Cost Categories	**Scenario 4**	**Scenario 7**	**Difference**
Metering System Infrastructure	$755,299	$861,960	$106,661
Communications Infrastructure	47,735	47,735	-0-
Information Technology Infrastructure	237,931	237,931	-0-
Customer Service Systems	214,069	214,069	-0-
Management and Miscellaneous Other	93,779	93,779	-0-
TOTAL:	$1,348,811	$1,455,472	$106,661

The only cost code that changes when evaluating Scenario 7 in relation to Scenario 4 is MS-12. In Scenario 7, this cost code captures the costs associated with the ALC program. The activities and associated costs are discussed in detail in the following section.

a) <u>Meter System Installation and Maintenance</u>

The only cost difference between Scenarios 4 and 7 is related to the ALC program. The ALC program modifies the existing air conditioning load control program to include an economic dispatch option. In addition, new digital and programmable thermostats are combined with the existing load control switches. Customers will be provided an incentive payment in exchange for allowing SCE to dispatch the program when most economically effective as well as when emergency situations arise.

In Scenario 7, the cost estimates of $107 million are incurred over the 2006 to 2021 timeframe and are captured in cost category MS-12. These estimates are based upon the assumption that we will have approximately 100,000 customers participating in our new ALC program.[40] A majority of the $107 million cost estimate is associated with the customer incentive payments. Customers who sign up on the ALC program will have the option of selecting from two different options during an event: 1) shedding 100 percent of their load, or 2) shedding fifty percent of their load, or increasing their temperature setting by 4° F. Incentive payments vary by the option selected and are paid only during the summer season, defined as the first Sunday in June to the first Sunday in October. The average incentive payment, assuming four ton per air conditioning unit and thirty days per month, is $86.40 for customers selecting the 100 percent load shed option. Customers opting for the fifty percent load shed option will receive on average $48.00. This fifty percent load shed incentive level is assumed to be the same as the incentive level associated with the 4°F set-back option. We also plan to incur minimal costs on an annual basis associated with program administration and customer communications.

b) <u>Communications Infrastructure</u>

The communication infrastructure costs for Scenario 7 should be identical to those contained in Scenario 4.[41]

c) <u>Information Technology Infrastructure</u>

The information technology infrastructure costs for Scenario 7 should be identical to those contained in Scenario 4.[42]

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[40] This estimate assumes that the customers that are participating on our existing air conditioning cycling program will be migrated to the new program.

[41] In the preliminary cost estimates for Scenario 7, there appears to be a $89,175 cost difference between Scenario 4 in cost codes C-1, C-10 and C-12. We are analyzing whether this cost difference is erroneous in the preliminary analysis and will update this number, as appropriate, in our final analysis.

[42] In the preliminary cost estimates for Scenario 7, there appears to be a $2.45 million cost difference between Scenario 4 in cost codes I-2, I-5, I-14 and I-16. We are analyzing whether this

Continued on the next page

d) Customer Service Systems

The customer service systems costs are the same in Scenario 7 as they are in Scenario 4.

e) Management and Miscellaneous Other

The management and miscellaneous other costs for Scenario 7 should be identical to those contained in Scenario 4.[43]

2. Benefits

Scenario 7 benefits are summarized below in Table 3-30. These benefits are the same as those described previously for Scenario 4, except the demand response benefits are expected to increase by $140.2 million (going from $659.2 million in Scenario 4 to $799.3 million in Scenario 7).

Continued from the previous page

cost difference is erroneous in the preliminary analysis and will update this number, as appropriate, in our final analysis.

[43] In the preliminary cost estimates for Scenario 7, there appears to be a $319,340 cost difference between Scenario 4 in cost code M-7, we are analyzing whether this cost difference is erroneous in the preliminary analysis and will update this number, as appropriate, in our final analysis.

Table 3-30 Summary of Benefits for Scenario 7 vs. Scenario 4 (000s in 2004 Pre-Tax Present Value Dollars)			
Benefit Categories	**Scenario 4**	**Scenario 7**	**Difference**
Systems Operations Benefits	$275,481	$275,481	$-0-
Customer Service Benefits	7,737	7,737	-0-
Management and Other Benefits	65,648	65,648	-0-
Demand Response Benefits	659,173	799,348	140,174
TOTAL:	$1,008,039	$1,148,213	$140,174

a) <u>System Operations Benefits [SB-1 through SB-13]</u>

The benefits in Scenario 7 are the same as those described in Scenario 4.

b) <u>Customer Service Benefits [CB-1 through CB-13]</u>

The benefits in Scenario 7 are the same as those described in Scenario 4.

c) <u>Management and Other Benefits [MB-1 through MB-10]</u>

The benefits in Scenario 7 are the same as those described in Scenario 4.

d) <u>Demand Response Benefits [DR-1 through DR-4]</u>

Under Scenario 7, eighty percent of residential customers would default to a CPP-F rate, and eighty percent of C&I customers less than 200 kW in demand would default to the CPP-V rate. Demand response benefits of customers above 200 kW are found in Scenarios 12 and 13 (*see* Volume 4). We do not include the costs and benefits of Scenarios 12 or 13 in Scenario 7. Residential customers opting out to a TOU rate or their current rate would be eligible to enroll in a Load Control program. If eighty percent of the residential customers are defaulted on CPP-F rates, this leaves only about 400,000 customers remaining to be eligible for load control. SCE also assumes a twenty-five percent market penetration for a load control program resulting in about 100,000 residential customers on load control, which is essentially equivalent to our existing A/C cycling program. So, we assume that for this scenario that there would be no significant growth of our ALC program above the current air conditioning cycling program. For small C&I customers, no reliability programs are assumed beyond the existing Smart Thermostat program. This is because we assume that if load control was offered to small C&I customers, it would be done so on a voluntary basis. Since that program is already available, we did not assume additional growth above today's program. The Demand Response benefits for this scenario are included in Table 3-31 below.

We used the same Ruling prescribed demand response benefit values for capacity and energy for reliability demand reductions as for price responsive demand. This is because in our October 15, 2004 demand response filing, we determine the cost effectiveness of ALC using similar values. We see no justification for differential valuations between price responsive demand and reliability demand reductions in this preliminary analysis. Even if ALC were assigned higher capacity and energy values than price responsive demand reductions, that differential would not result in a higher NPV for this Scenario relative to business as usual which would have the full roll out of ALC.

Table 3-31 CPP-F/CPP-V Default with Opt-Out Plus Reliability (Scenario 7)			
	No. of Meters (Customers) Year 2021	**Percent of Eligible Meters**	**Present Value ($ millions)**
Meters Eligible for TDRs	5,114,245		
Customers Enrolled on CPP-F/V	4,091,396	80	$643
Customers Enrolled on Current	511,424	10	$0
Customers Enrolled on TOU	511,424	8	$17
Customers Enrolled in ALC	100,000	2	$140
Total DR-1 Benefits			$702
Total DR-2 Benefits			$98
Total Demand Response Benefits			$800

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B. For this scenario, the Value of Service loss is approximately $340 million ($2004 present value), reducing the total demand response benefit from $800 to $460 million.

3. <u>Uncertainty and Risk Analysis</u>

For Scenario 7, the total present value cost estimate is $1.455 billion. We developed cost ranges as described in Section III.C and applied a Monte Carlo statistical analysis of costs that resulted in a range of $1.427 billion to $1.598 billion around the estimated cost of $1.455 billion for this scenario. The statistical analysis indicates that our cost estimate has less than a 10% confidence. This means that the project has a ninety percent chance of overrunning. Our preliminary cost estimates do not include contingency. However, based on our analysis we should consider a contingency of approximately $83 million in our final application to reduce the risk of overrun. This contingency amount is the difference between our cost estimate and the value at the ninety percent confidence level.

The demand response uncertainty of this scenario is the same as stated in Scenario 4 above.

4. Net Present Value Analysis

Table 3-32 summarizes the overall pre-tax costs and benefits of Scenario 7. Also shown is the after-tax NPV for this scenario on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period.

Table 3-32
Summary of Cost/Benefit Analysis for Scenario 7 (000s)

Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. Present Value
$1,458.3	$1,148.2	($310.1)	($251.3)	($793.5)

Scenario 7 analysis results in a negative Revenue Requirement Present Value of $793.5 million, and it does not support the implementation of full AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the Scenario 7 analysis, plus the recovery of SCE's net investment in any removed meters, plus the rate of return and tax impacts of the AMI-related investments.

G. Scenario 8: Operational Plus Demand Response Plus Reliability - Current Default with Opt-In to CPP Pure

Scenario 8 also adds a reliability element to the full operational deployment of AMI. For the reliability component of this scenario, as was the case in Scenario

7, we chose the Advanced Load Control (ALC) program that was included as part of our LTPP in our 2005 Demand Response Proposals filed on October 15, 2004.[44] As with Scenario 5, Scenario 8 assumes the existing tariff structures will remain as the "default" tariff and twenty-two percent of the customers will opt in to a "CPP-Pure" rate option. Scenario 8 differs from Scenario 5 in that the costs and benefits of the ALC program are included in this scenario. As mentioned previously, AMI and ALC are not mutually exclusive and this scenario recognizes the interaction of these two programs.

Since we are to assume that only twenty-three percent of customers are on CPP rates in this scenario, our ALC program and customer projections are only partially curtailed. Independent of a CPP tariff for residential customers, the program is projected to attract 500,000 participants. In this scenario, we assume roughly twenty percent of the full ALC rollout would be precluded by CPP customers. So, we therefore, assume that 420,000 customers will participate in ALC.

1. **Costs**

Table 3-33 summarizes the cost by category of Scenario 8 compared to the costs for Scenario 5.

[44] SCE's Demand Response Program Proposals for 2005-2008, in R. 04-04-003

Table 3-33 Summary of Costs for Scenario 8 vs. Scenario 5 (000s in 2004 Pre-Tax Present Value Dollars)			
Cost Categories	**Scenario 5**	**Scenario 8**	**Difference**
Metering System Infrastructure	$755,299	$1,024,169	$268,870
Communications Infrastructure	47,829	47,829	0
Information Technology Infrastructure	228,877	228,877	0
Customer Service Systems	183,737	183,315	(422)
Management and Miscellaneous Other	50,141	42,997	(7,144)
TOTAL:	$1,265,882	$1,529,726	$263,844

The activities and associated costs are discussed in detail in the following section.

a) Meter System Installation and Maintenance

The most significant cost difference between Scenarios 5 and 8 is related to the ALC program. The ALC program modifies the existing air conditioning load control program to include an economic dispatch option. In addition, new digital and programmable thermostats are combined with the existing load control switches. Customers will be provided an incentive payment in exchange for allowing SCE to dispatch the program when most economically effective as well as when emergency situations arise.

In Scenario 8, the cost estimates of $268.9 million, which are captured in cost code MS-12, are based upon the assumption that we will have approximately 420,000 customers participating in our new ALC program by 2011.[45] We are also assuming that the ALC program is approved in early 2005.

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[45] This estimate assumes that the customers that are participating in our existing air conditioning cycling program will be migrated to the new program.

The cost estimate of $268.9 million is comprised of the costs associated with equipment, installation, customer incentive payments and program administration that are incurred over the 2006 to 2021 timeframe. We will incur equipment and installation costs associated with enrolling additional customers on the new ALC program. In terms of equipment costs, our estimates are based upon thirty percent of participating customers choosing to have a direct load control switch installed on their air conditioning unit. This installation will be handled by a contractor resource. The equipment and installation costs are estimated at $161 per customer.

For the remaining seventy percent of customers, we are assuming that a load control transceiver will be embedded in the AMI meter.[46] This transceiver will have the ability to control the customer's air conditioning unit by communicating with the customer's thermostat. The equipment costs associated with the thermostat and load control transceiver are estimated to be $95 per customer. In addition, we will incur installation costs. The contractor resource costs associated with installing a thermostat in a customer's home or business are estimated to be $90. In terms of the load control transceiver installation costs, we are assuming that fifty percent of the meters will have the module embedded by the vendor at the time of manufacturing. In these cases, there will be no additional installation costs since we will be utilizing the installers discussed in cost code MS-5 in Scenario 1 to handle the installation of the AMI meters. However, in fifty percent of the cases, we are assuming that the AMI meter will already have been installed and will need to be replaced with one that contains the load control transceiver. In those cases, we have captured the costs associated with having an installer visit the customer's site to reinstall the meter.

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[46] Conceptual design is neither proven nor commercially available today.

The majority of the $268.9 million cost estimate can be attributed to customer incentive payments. Customers who sign up on the ALC program will have the option of selecting from two different options during an event: 1) shedding 100 percent of their load, or 2) shedding fifty percent of their load, or increasing their temperature setting by 4º F. Incentive payments vary by the option selected and are paid only during the summer season, defined as the first Sunday in June to first Sunday in October. The average incentive payment, assuming four ton per air conditioning unit and thirty days per month, is $86.40 for customers selecting the 100 percent load shed option. Customers opting for the fifty percent load shed option will receive on average $48.00. This fifty percent load shed incentive level is assumed to be the same as the incentive level associated with the 4ºF set-back option. We also plan to incur minimal costs on an annual basis associated with program administration and customer communications.

b) Communications Infrastructure

The communications infrastructure costs for Scenario 8 should be identical to those contained in Scenario 5.[47]

c) Information Technology Infrastructure

The information technology infrastructure costs for Scenario 8 should be identical to those contained in Scenario 5.[48]

[47] In the preliminary cost estimates for Scenario 8, there appears to be a $89,175 cost difference between Scenario 5 in cost codes C-1, C-10 and C-12. We are analyzing whether this cost difference is erroneous in the preliminary analysis and will update this number, as appropriate, in our final analysis.

[48] In the preliminary cost estimates for Scenario 8, there appears to be a $2.45 million cost difference between Scenario 5 in cost codes I-2, I-5, I-14, and I-16. We are analyzing whether this cost difference is erroneous in the preliminary analysis and will update this number, as appropriate, in our final analysis.

d) Customer Service Systems

Customer Communications and Marketing costs (cost code CU-10) are decreasing by $422,362 between Scenario 5 and 8. This is due to the assumption that the "opt-in" participation rate will be lower for Scenario 8 than assumed for Scenario 5. The smaller participant base on CPP rates affects the mass media costs and the CPP event notification costs.

e) Management and Miscellaneous Other

The management and miscellaneous other costs that are captured in cost code M-14 are decreasing by $7.5 million between Scenario 5 and 8. Cost code M-14 relates to customer acquisition and marketing costs which will also be reduced due to the assumed reduction in customer opt-in participation on CPP rates under Scenario 8 relative to Scenario 5.

With regard to the remaining cost difference, the costs captured in M-7 of this scenario should be identical to those contained in Scenario 5.[49]

2. Benefits

Table 3-34 summarizes Scenario 5 and Scenario 8 benefits by category.

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[49] In the preliminary cost estimates for Scenario 8, there appears to be a $319,340 cost difference between Scenario 5 in cost code M-7. We are analyzing whether this cost difference is erroneous in the preliminary analysis and will update this number, as appropriate, in our final analysis.

Table 3-34 Summary of Benefits for Scenario 8 000s in 2004 Pre-Tax Present Value Dollars)			
Benefit Categories	**Scenario 5**	**Scenario 8**	**Difference**
Systems Operations Benefits	$275,481	$275,481	-0-
Customer Service Benefits	$7,737	$7,737	-0-
Management and Other Benefits	$65,648	$65,648	-0-
Demand Response Benefits	$162,817	580,663	$417,846
TOTAL:	$511,683	$929,529	$417,846

As in Scenario 5, this scenario assumes that residential and C&I customers will opt in to the CPP-Pure rate and that a group of other residential customers, either on a TOU rate or their current rate would enroll in ALC, providing a reliability feature. SCE used the MMI model to determine customer enrollment percentage in the first year and used that same percentage for every year in the analysis. For the purposes of the analysis, SCE used the demand response behavior in the SPP for CPP-F as a proxy for CPP-Pure since the latter was not tested in the experiment. The demand response benefits are shown in Table 3-35 below.

Table 3-35 **Current Default with Opt-in to CPP-Pure Plus Reliability (Scenario 8)**			
	No. of Meters (Customers) Year 2021	**Percent of Eligible Meters**	**Present Value ($millions)**
Meters Eligible for TDRs	5,114,245		
Customers Enrolled on CPP-Pure	851,805	16	$162
Customers Enrolled on Current	4,262,440	84	$0
Customers Enrolled on ALC	420,000	0	$418
Total DR-1 Benefits			$509
Total DR-2 Benefits			$71
Total DR Benefits			$581

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B. For this scenario, the Value of Service loss is approximately $ 81 million (2004 present value dollars), reducing the total demand response benefit from $581 to $500 million.

3. Uncertainty and Risk Analysis

Scenario 8 costs and operational benefit risks and analysis results are similar to that of Scenario 3.

The uncertainties and risks associated with demand response of this scenario are the same as those for Scenario 5 described above.

4. Net Present Value Analysis

Table 3-36 summarizes the overall pre-tax costs and benefits of Scenario 8. Also shown is the after-tax NPV for this scenario on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period.

Table 3-36 Summary of Cost/Benefit Analysis for Scenario 8 ($ Millions)				
Costs	**Benefits**	**Pre-tax Present Value**	**After-Tax NPV**	**Rev. Req. Present Value**
$1,529.7	$929.5	($600.2)	($423.7)	($1,084.5)

Our Scenario 8 analysis results in a negative Revenue Requirement Present Value of $1,084.5 million and does not support the implementation of full AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the Scenario 8 analysis, plus the recovery of SCE's net investment in any removed meters, plus the rate of return and tax impacts of the AMI-related investments.

H. Scenario 9 and Scenario 10: SCE's Alternative Analysis for Operational Plus Demand Response – TOU Default with Opt-out (Scenario 9) and CPP-F/CPP-V Default with Opt-out (Scenario 10)

Scenario 3 and Scenario 4 presented earlier in this volume were required by the Ruling and both included an assumption of twenty percent opt-out from their respective default rates (*i.e.,* TOU and CPP respectively). As explained in the Introduction to this volume, SCE does not agree that it is reasonable to assume eighty percent customer participation for the duration of the analysis period, on either the TOU default rate or the CPP default rates, given an opt-out alternative. For the purposes of determining the sensitivity of costs and benefits to customer participation rates, we have assumed a more realistic fifty percent opt-out rate. Scenarios 9 and 10 were designed to provide a comparative analysis based on this assumption.

Table 3-37 summarizes the costs and benefits expected to result from these two scenarios compared to the two twenty percent opt-out equivalent scenarios.

Table 3-37 Comparison of Costs, Benefits, and NPV for Scenarios 3, 4, 9 and 10 (000s in 2004 Pre-Tax Present Value Dollars)				
	Scenario 3 20% Opt-out TOU	**Scenario 4 20% Opt-out CPP**	**Scenario 9 50% Opt-out TOU**	**Scenario 10 50% Opt-out CPP**
Costs	$1,327,183	$1,348,811	$1,327,927	$1,335,906
Benefits	$564,776	$1,008,039	523,026	634,409
Pre-Tax PV	($762,406)	($340,772)	($804,901)	($701,498)

1. Costs

As was the case with Scenarios 3 and 4, the only operational cost differences between Scenarios 9 and 10 relate to the marketing costs associated with critical-peak event notification (cost code CU-10). Critical peak event notification costs are proportionate to the number of CPP rate participants, and are significantly higher for CPP default rate Scenarios 4 and 10 than for TOU default rate Scenarios 3 and 9. Scenario 4 marketing costs are $22 million higher than for Scenario 3 and Scenario 10 marketing costs are $8 million higher than for Scenario 9.

Table 3-38 shows the costs by cost category for Scenarios 9 and 10 and compares them to Scenarios 3 and 4.

Table 3-38 Summary of Costs for Scenarios 3, 4, 9 and 10 (000s in 2004 Pre-Tax Present Value Dollars)				
Cost Categories	**Scenario 3**	**Scenario 4**	**Scenario 9**	**Scenario 10**
Metering System Infrastructure*	$755,299	$755,299	$755,299	$755,299
Communications Infrastructure	47,734	47,734	47,829	47,829
Information Technology Infrastructure	237,931	237,931	250,480	250,480
Customer Service Systems (W/O Mktg.)	64,326	64,326	71,491	71,491
Marketing (CU-10 only)	128,114	149,743	133,263	141,242
Management and Miscellaneous Other	93,779	93,779	69,566	69,566
COST TOTAL:	1,327,183	1,348,811	1,327,927	1,335,906

*Includes FSMRO Severance cost

a) Meter System Installation and Maintenance

For Scenarios 9 and 10, the costs are identical to those described in Scenarios 3 and 4.

b) Communications Infrastructure

The communications infrastructure costs for Scenarios 9 and 10 should be identical to Scenarios 3 and 4.[50]

c) Information Technology Infrastructure (I-9 and I-11)

In Scenarios 9 and 10, the cost differences relative to Scenarios 3 and 4 are contained within 2 cost codes, I-9 and I-11. With regard to cost code I-9,

[50] In the preliminary cost estimates for Scenarios 9 and 10, there appears to be a $94,060 cost difference between Scenarios 3 and 4 in cost code C-5. We are analyzing whether this cost difference is erroneous in the preliminary analysis and will update this number, as appropriate, in our final analysis.

the costs our Billing Organization will incur are expected to increase from $60.3 million to $61.3 million. We anticipate that we will need additional analyst support from 2011 – 2021. In cost code I-11, the costs our Billing Organization will incur to handle opt-out processing will increase as the number of customers opting-out increases from twenty percent to fifty percent. Our personnel estimates reach a peak of 57.2 FTEs in 2007 and decline to a steady state of 24.8 FTEs from 2011 to 2021. As such, our cost estimates increase from $6.3 million to $17.9 million.

d) Customer Service Systems Costs (CU-2, CU-5, CU-8, CU-9, and CU-10)

Call Center costs in cost code CU-2 are expected to increase by $6.9 million (over the cost estimate for Scenarios 3 and 4) through 2021. Though we anticipate there will be fewer billing related calls and fewer critical peak pricing event calls into the Call Center under the fifty percent opt-out scenarios, we expect an overall increase in call volume due to the larger number of opt-out calls that are expected under Scenarios 9 and 10. Similarly, the Billing Organization expects $1.3 million in additional cost in cost code CU-5 due to an increase in the number of requests for billing analyses. The Call Center also expects increased call volume for rate changes (CU-8) resulting in an increase of $0.9 million, and a slight increase ($80,000) for questions relating to Internet usage data (CU-9).

The fifty percent opt-out assumption for TOU default in Scenario 9 results in a $5.1 million increase in Marketing costs for CPP event notification (CU-10) over that expected in the twenty percent opt-out case (Scenario 3). This is because we have assumed that one-half of the TOU opt-outs will opt in to the CPP rate. On the other hand, CPP event notification costs for Scenario 10 are expected to be $8.5 million less than that expected for Scenario 4. Again, these costs are a function of the number of CPP participants expected on each respective rate schedule (*see* Table 3-39 below).

e) Management and Other Costs (M-7, M-10, and M-14)

Project management and overhead costs in cost code M-7 are expected to increase by $2.5 million for the Call Center and $0.5 million for the Billing Organization in both of the fifty percent opt-out scenarios. This is directly related to the increase in opt-out calls, billing calls and rate analysis that is anticipated for Scenarios 9 and 10 versus Scenarios 3 and 4.

Mass media customer communications requirements are expected to be lower for Scenarios 9 and 10 than for Scenarios 3 and 4. This is expected to result in a decrease in Marketing costs of $27.7 million in cost code M-14 for both Scenarios 9 and 10 compared to Scenarios 3 and 4.

2. Benefits

Table 3-39 shows the expected benefits by benefit category for Scenarios 3, 4, 9 and 10.

Table 3-39
Summary of Benefits for Scenarios 3, 4, 9 and 10
(000s in 2004 Pre-Tax Present Value Dollars)

Benefit Categories	Scenario 3	Scenario 4	Scenario 9	Scenario 10
Systems Operations	$275,481	$275,481	$275,481	$275,481
Customer Service	7,737	7,737	7,737	7,737
Management and Other	65,648	65,648	65,648	65,648
Demand Response	215,910	659,173	174,161	285,543
TOTAL:	$564,776	$1,008,039	$523,026	$634,409

Because we expect a significantly different customer mix on CPP versus TOU and Tiered rates in the fifty percent opt-out scenarios, we also expect a significantly different demand response. For the TOU default scenarios, the demand response load reduction is higher for Scenario 9 than for Scenario 3 because of higher CPP participation. We expect that one-half of those opting out of TOU rates in Scenario 9 will actually opt for the CPP rate schedule instead of the otherwise applicable tiered rates. On the other hand, the fifty percent CPP default Scenario 10 assumes lower CPP participation than for Scenario 4 with an eighty percent participation. Although we assume one-half of the opt-outs in Scenario 10 will actually opt in to TOU rates rather than to tiered rates, the expected demand response benefit for Scenario 10 is $374 million lower than for Scenario 4. The lower benefit is also due to lower assigned capacity value of demand reductions in Scenarios 9 and 10 compared to the Ruling's assigned value of $85/kW for Scenarios 3 and 4, as further described below. Table 3-40 shows the expected customer participation rates on the alternative rate schedules for the four scenarios.

Table 3-40
2021 Customer Participation by Rate Schedule
(Scenarios 3, 4, 9 and 10)

	Scenario 3	Scenario 4	Scenario 9	Scenario 10
Eligible Meters	5,114,245	5,114,245	5,114,244	5,114,244
Customers on TOU	4,091,396	511,424	2,557,122	1,278,561
Customers on CPP-F/V	511,424	4,091,396	1,278,561	2,557,122
Customers on Tiered	511,424	511,424	1,278,561	1,278,561

Scenario 9 assumes that only fifty percent of eligible customers default to TOU rates and those customers stay on that rate for the full duration of the business case.

The demand response benefits for Scenarios 9 and 10 are computed differently than for previous scenarios. Under these scenarios, we applied the load reduction from TDRs as a reduction in our load forecast and therefore discounted the quantity of load reduction available that could be counted as a reduction in the forecast. We used our portfolio approach to valuing the capacity and energy benefits from the planned load reductions. The summary of demand response benefits are shown in Tables 3-41 and 3-42, respectively below.

Table 3-41
TOU Default with Opt-out to CPP-F or Current (Scenario 9)

	No. of Meters (Customers) Year 2021	Percent of Eligible Meters	Present Value ($ millions)
Meters Eligible for TDRs	5,114,245		
Customers Enrolled on TOU	2,557,122	50	
Customers Enrolled on CPP-F	1,278,561	25	
Customers Enrolled on Current	1,278,561	25	$0
DR-1 Benefits			$150
DR-2 Benefits			$24
Total DR Benefits			$174

Table 3-42 CPP-F/V Default with Opt-out to TOU or Current (Scenario 10)			
	No. of Meters (Customers) Year 2021	**Percent of Eligible Meters**	**Present Value ($ millions)**
Meters Eligible for TDRs	5,114,245		
Customers Enrolled on CPP-F/V	2,557,122	50	
Customers Enrolled on TOU	1,278,561	25	
Customers Enrolled on Current	1,278,561	25	$0
DR-1 Benefits			$241.3
DR-2 Benefits			$44.2
Total DR Benefits			$285.5

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B. For Scenario 9, the Value of Service loss is approximately $37 million (2004 present value dollars), reducing the total demand response benefit from $174 to $137 million. For Scenario 10, the Value of Service loss is approximately $227 million (2004 present value dollars), reducing the total demand response benefit from $286 to $58 million.

3. Uncertainty and Risk Analysis

Scenario 9 and 10 costs and operational benefit risks and analysis results are similar to that of Scenario 3.

In addition, as discussed in Volume 2, Section IV.5, because the statutory constraints of AB1-X are expected to be effective until 2014, we believe that an appropriate assumption is that these legal restrictions do apply, and TDRs would not be effective until 2014. We considered the following sensitivity analyses. If the Ruling's required deployment window of 2006-2011 is carried out and TDRs cannot be implemented until 2014, then the demand response benefits would be substantially reduced. For Scenario 9, the present value of demand response benefits would decline from $174 million to $30 million. For Scenario 10, the present value of demand response benefits would decline from $286 million to $125 million.

4. Net Present Value Analysis

Table 3-43 summarizes the overall pre-tax costs and benefits of Scenarios 9 and 10. Also shown, is the after-tax NPV for these scenarios on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period.

Table 3-43
Summary of Net Present Value Analysis for Scenarios 9 & 10
($ Millions)

Scenario	Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. Present Value
Scenario 9	$1,327.9	$523.0	($804.9)	($545.3)	($1,286.8)
Scenario 10	$1,335.9	$634.4	($701.5)	($483.9)	($1,184.2)

Our analysis for Scenario 9 resulted in a negative Revenue Requirement present Value of $1,286.8 million. Our analysis for Scenario 10 resulted in a negative Revenue Requirement present value of $1,184.2 million. Neither of these two scenarios supports the implementation of full AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the Scenarios 9 and 10 analyses, plus the recovery of SCE's net investment in any removed meters, plus the rate of return and tax impacts of the AMI-related investments.

I. Scenario 11: SCE's Alternative Analysis for Full Deployment Business Case - Operational Plus Demand Response Plus Reliability

Scenario 11 is similar to Scenario 10 except that it adds a reliability element to the full operational deployment of AMI. For the reliability component of this scenario, we have chosen the same ALC program chosen as the reliability component of Scenarios 7 and 8; that is the ALC program included as part of our LTPP filed on October 15, 2004.[51] As with Scenario 10, Scenario 11 assumes the default rate is CPP-F for residential customers and CPP-V for C & I customers. It also assumes the more reasonable opt-out rate of fifty percent that was assumed in Scenario 10. Scenario 11 differs from Scenario 10 in that the costs and benefits of the ALC program are included in this scenario.

Since we are to assume that fifty percent of customers are on CPP rates in this scenario, our ALC program and customer projections are necessarily curtailed. Independent of AMI, the program is projected to attract 500,000 customers. In this scenario, we assume only 250,000 customers will participate in ALC given the CPP rates. This scenario includes the lower costs and benefits of our ALC program as well as the secondary (resource plan) impacts of those program reductions. We use our recommended assumptions for avoided costs in this scenario. Specifically, placing fifty percent of customers on CPP rates would mean that our ALC program is reduced by fifty percent. Thus, the avoided cost value for MWs of ALC in the resource plan displaced by CPP and TOU is the cost of ALC rather than a combustion turbine. For MWs displaced by CPP and TOU above the maximum

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[51] SCE's (U-338-E) Demand Response Program Proposals for 2005-2008, in R. 04-04-003

deployment of ALC in the resource plan, the value of avoided costs is the next most expensive resource, a combustion turbine.

1. Costs

Table 3-44 Summary of Costs for Scenario 11 vs. Scenario 10 (000s in 2004 Pre-Tax Present Value Dollars)			
Cost Categories	**Scenario 10**	**Scenario 11**	**Difference**
Metering System Infrastructure	$755,299	$929,450	$174,151
Communications Infrastructure	47,829	47,829	-0-
Information Technology Infrastructure	250,480	250,480	-0-
Customer Service Systems	212,733	212,733	-0-
Management and Miscellaneous Other	69,566	69,566	-0-
TOTAL:	$1,335,906	$1,510,058	$174,151

The only cost code that changes when evaluating Scenario 11 in relation to Scenario 10 is MS-12. In Scenario 11, this cost code captures the costs associated with the ALC program. The activities and associated costs are discussed in detail in the following section

a) Meter System Installation and Maintenance

The only cost difference between Scenarios 10 and 11 is related to the ALC program. The ALC program modifies the existing air conditioning load control program to include an economic dispatch option. In addition, new digital and programmable thermostats are combined with the existing load control switches. Customers will be provided an incentive payment in exchange for allowing SCE to dispatch the program when most economically effective as well as when emergency situations arise.

In Scenario 11, the cost estimates of $174.2 million, which are captured in cost category MS-12, are based upon the assumption that we will have approximately 250,000 customers participating in our new ALC program by 2011.[52] We are also assuming that the ALC program is approved in early 2005 and the equipment necessary to participate in the program is installed at approximately 142,000 of participating customers' homes within 2005.

The cost estimate of $174.2 million is comprised of the costs associated with equipment, installation, customer incentive payments and program administration that are incurred over the 2006 to 2021 timeframe. Beginning in 2006, we will incur equipment and installation costs associated with enrolling over 100,000 customers on the new ALC program. In terms of equipment costs, our estimates are based upon thirty percent of participating customers choosing to have a direct load control switch installed on their air conditioning unit. This installation will be handled by a contractor resource. The equipment and installation cost is estimated at $161 per customer.

For the remaining seventy percent of customers, we are assuming that a load control transceiver will be embedded in the AMI meter.[53] This transceiver will have the ability to control the customer's air conditioning unit by communicating with the customer's thermostat. The equipment costs associated with the thermostat and load control transceiver are estimated to be $95 per customer. In addition, we will incur installation costs. The contractor resource costs associated with installing a thermostat in a customer's home are estimated to be $90. In terms of the load control transceiver installation costs, we are assuming that fifty percent of the meters will have the module embedded by the vendor at the

[52] This estimate assumes that the existing customers that are participating on our existing air conditioning cycling program will be migrated to the new program.

[53] Conceptual design is neither proven nor commercially available today

time of manufacturing. In these cases, there will be no additional installation costs since we will be utilizing the installers discussed in cost code MS-5 in Scenario 1 to handle the installation of the AMI meters. However, in fifty percent of the cases, we are assuming that the AMI meter will already have been installed and will be need to be replaced with one that contains the load control transceiver. In those cases, we have captured the costs associated with having an installer visit the customer's site to reinstall the meter.

The majority of the $174.2 million cost estimate can be attributed to customer incentive payments. Customers who sign up on the ALC program will have the option of selecting from two different options during an event: 1) shedding 100 percent of their load, or 2) shedding fifty percent of their load, or increasing their temperature setting by 4º F. Incentive payments vary by the option selected and are paid only during the summer season, defined as the first Sunday in June to first Sunday in October. The average incentive payment, assuming 4 ton per air conditioning unit and thirty days per month, is $86.40 for customers selecting the 100 percent load shed option. Customers opting for the fifty percent load shed option will receive on average $48.00. This fifty percent load shed incentive level is assumed to be the same as the incentive level associated with the 4ºF set-back option. We also plan to incur minimal costs on an annual basis associated with program administration and customer communications.

b) Communications Infrastructure

The communications infrastructure costs for Scenario 11 should be identical to those contained in Scenario 10.[54]

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[54] In the preliminary cost estimates for Scenario 11, there appears to be a $89,175 cost difference between Scenario 10 in cost codes C-1, C-10 and C-12. We are analyzing whether this cost difference is erroneous in the preliminary analysis and will update this number, as appropriate, in our final analysis.

c) Information Technology Infrastructure

The information technology infrastructure costs for Scenario 11 should be identical to those contained in Scenario 10.[55]

d) Customer Service Systems

The customer service systems costs are the same as those described in Scenario 10.

e) Management and Miscellaneous Other

The management and miscellaneous other costs should be identical to those contained in Scenario 10.[56]

2. Benefits

Scenario 11 benefits are listed by category in Table 3-45.

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[55] In the preliminary cost estimates for Scenario 11, there appears to be a $2.45 million cost difference between Scenario 10 in cost codes I-2, I-5, I-14, and I-16. We are analyzing whether this cost difference is erroneous in the preliminary analysis and will update this number, as appropriate, in our final analysis.

[56] In the preliminary cost estimates for Scenario 11, there appears to be a $319,340 cost difference between Scenario 10 in cost code M-7. We are analyzing whether this cost difference is erroneous in the preliminary analysis and will update this number, as appropriate, in our final analysis.

Table 3-45 Summary of Benefits for Scenario 11 (000s in 2004 Pre-Tax Present Value Dollars)	
Benefit Categories	**Total**
Systems Operations Benefits	$275,481
Customer Service Benefits	7,737
Management and Other Benefits	65,648
Demand Response Benefits	386,841
TOTAL:	$735,707

This scenario is the same as Scenario 10 except ALC is added as a dispatchable resource for reliability for residential customers. Under this scenario, SCE employed the MMI model to estimate the default enrollments for residential and C&I customers on CPP-F/V rates. Residential customers opting out to a TOU rate or their current rate would be eligible to enroll in ALC. As in Scenario 7 for small C&I customers, no reliability programs are assumed beyond the existing Smart Thermostat program. For large C&I customers, SCE's I-6 program would provide reliability and its benefits are included in Table 3-46 below.

We used our portfolio approach to determine procurement benefits and DR-1 and DR-2, as described above.

Table 3-46 CPP-F/CPP-V Default with Opt-Out Plus Reliability With SCE Enrollment Adjustment (Scenario 11)			
	No. of Meters (Customers) Year 2021	**Percent of Eligible Meters**	**Present Value ($ millions)**
Meters Eligible for TDRs	5,114,245		
Customers Enrolled on CPP-F/V	2,557,122	50	$
Customers Enrolled on Current	1,028,561	20	$0
Customers Enrolled on TOU	1,278,561	25	
Customers Enrolled in AC cycling	2,500,000	5	$0
DR-1 Benefits			$336
DR-2 Benefits			$51
Total Demand Response Benefits			$387

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B. For this scenario, the Value of Service loss is approximately $227 million (2004 present value dollars), reducing the total demand response benefit from $387 to $160 million.

3. Uncertainty and Risk Analysis

Scenario 11 costs and operational benefit risks and analysis results are similar to that of Scenario 3.

In addition with regard to demand response uncertainty, as discussed in Volume 2, Section IV.5, because the statutory constraints of AB1-X are expected to be effective until 2014, we believe that an appropriate assumption is that these legal restrictions do apply and TDRs would not be effective until 2014. We considered the following sensitivity analyses. If the Ruling's required deployment window of 2006-2011 is carried out and TDRs cannot be implemented until 2014, then the demand response benefits would be substantially reduced. For Scenario 11, the present value of demand response benefits would decline from $387 million to $169 million.

4. Net Present Value Analysis

Table 3-47 summarizes the overall pre-tax costs and benefits of Scenario 11. Also shown is the after-tax NPV for this scenario on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period.

Table 3-47
Summary of Cost/Benefit Analysis for Scenario 11
($ Millions)

Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. Present Value
$1,512.9	$735.7	($777.2)	($528.9)	($1,261.2)

Scenario 11 analysis results in a negative Revenue Requirement present value of $1,261.2 million and does not support the implementation of full AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the Scenario 11 analysis, plus the recovery of SCE's net investment in any removed meters, plus the rate of return and tax impacts of the AMI-related investments.

IV.

REVENUE REQUIREMENT AND CUSTOMER IMPACT ANALYSIS

The purpose of this section is to present our preliminary estimated net AMI-related revenue requirement and customer impacts for the years 2006 through 2021 for the full deployment scenarios.[57] The preliminary revenue requirement presented in this section summarizes the operating expenses and investment-related costs identified in Section III above. A cost recovery and ratemaking proposal to recover the AMI-related revenue requirements will be provided in our December 2005 AMI filing.

Table 3-48 provides the estimated net AMI-related revenue requirement and average customer monthly dollar impacts for each of the full deployment scenarios.

The estimated net AMI-related revenue requirement impacts by year for each scenario are calculated by subtracting the expected AMI benefits-related revenue requirement reductions from the estimated AMI cost-related revenue requirement. For illustrative purposes, SCE has also calculated a customer monthly dollar impact by year for each scenario. In order to calculate the average customer impacts, SCE utilized the total system retail customer forecast as presented in SCE's 2004 LTPP testimony filed on July 9, 2004 in R.04-04-003.

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57 Due to the Ruling's prescribed 2006-2021 analysis period, the revenue requirement analysis does not include recovery of the remaining AMI-related plant investment as of the end of 2021, primarily for meters which would be installed or replaced between 2007 and 2020. These unrecovered costs [of approximately $190 million in unrecovered net plant for the full-deployment scenarios (scenarios 1-11), and $19 million for the Zone 4 partial-deployment scenarios (Scenarios 14-23),] would be a continuing ratepayer obligation post-2021, although they also would be expected to provide a useful life past 2021, due to the underlying assets' fifteen-year life and their later in-service dates.

A. AMI-related Revenue Requirement Increases

The AMI-related Revenue Requirement increase is comprised of two components: 1) New Meter Revenue Requirement; and 2) Stranded Cost Revenue Requirement. The New Meter Revenue Requirement represents the recovery of anticipated O&M expenses and capital costs associated with expected rate base amounts including depreciation, applicable taxes and return on rate base calculated at the Commission-authorized rate of return.[58] The return on rate base amounts included in the Revenue Requirements presented in Table 3-48 uses our currently authorized rate of return on rate base of 9.75 percent.

As discussed in Sections II and III of this volume, new meters will be placed in service over a five-year period (2006 through 2010). As the new meters are deployed, the existing or replaced meters will become stranded costs and the undepreciated balance, including anticipated negative net salvage, associated with these meters must be recovered in rate levels. As such, SCE proposes to amortize the stranded meters undepreciated net investment over the five-year new meter deployment period which will commence on January 1, 2006 and has reflected this proposal in this revenue requirement analysis. The net investment of the stranded meters will include plant and accumulated depreciation. The stranded cost revenue requirement also includes amortization, applicable taxes and an authorized return on rate base.

B. Expected Revenue Requirement Reductions

In order to estimate the net AMI-related revenue requirement impacts, the expected cost savings derived from the AMI benefits have been deducted from the AMI cost-related revenue requirement increase. The cost savings or revenue

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[58] SCE has assumed a fifteen-year recovery period associated with the new meters.

requirement reductions include: (1) Customer Service-related O&M reductions; (2) existing meter revenue requirement reductions; and (3) procurement cost reductions due to demand response.

Table 3-48
AMI Revenue Requirement and Average Monthly Customer Impact (Full AMI Deployment)
(000s of Dollars)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Scenario 1 - Full-Operational-Utility																
AMI Meter Installation Revenue Requirements	79,564	102,596	151,834	179,069	215,999	193,914	187,597	182,912	178,969	176,730	175,392	173,830	170,192	166,587	159,716	145,982
Stranded Cost Revenue Requirement - 5 year	117,522	112,959	104,084	72,591	127,088	-	-	-	-	-	-	-	-	-	-	-
Less:																
Expected O&M Reductions	(60)	(7,797)	(27,202)	(43,815)	(52,973)	(56,302)	(57,277)	(59,203)	(61,452)	(63,542)	(65,936)	(68,182)	(70,766)	(72,725)	(74,692)	(76,812)
Meter Revenue Requirement in Rates	(2,977)	(2,041)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)
Expected Procurement Reductions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net AMI-related Rev Req Impact	**194,048**	**205,716**	**223,806**	**202,933**	**285,203**	**132,701**	**125,409**	**118,798**	**112,606**	**108,277**	**104,545**	**100,737**	**94,514**	**88,951**	**80,113**	**64,258**
Avg Monthly Customer Dollar Impact	**3.36**	**3.52**	**3.77**	**3.38**	**4.68**	**2.15**	**2.01**	**1.88**	**1.76**	**1.67**	**1.59**	**1.52**	**1.41**	**1.31**	**1.17**	**0.92**
Scenario 3 - Full-DR-TOU-Opt-20																
AMI Meter Installation Revenue Requirements	134,947	161,795	215,176	241,291	277,291	247,568	240,152	236,626	231,096	231,566	198,556	199,432	195,629	191,335	184,006	167,639
Stranded Cost Revenue Requirement - 5 year	117,522	112,959	104,084	72,591	127,088	-	-	-	-	-	-	-	-	-	-	-
Less:																
Expected O&M Reductions	(42)	(8,352)	(27,754)	(44,385)	(53,675)	(56,937)	(57,933)	(59,882)	(62,154)	(64,268)	(66,686)	(68,958)	(71,568)	(73,552)	(75,542)	(77,689)
Meter Revenue Requirement in Rates	(2,977)	(2,041)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)
Expected Procurement Reductions	(53)	(10,216)	(20,416)	(30,654)	(39,235)	(42,945)	(43,489)	(44,046)	(44,607)	(45,180)	(45,754)	(46,342)	(46,933)	(47,536)	(48,143)	(48,765)
Total Net AMI-related Rev Req Impact	**249,397**	**254,145**	**266,180**	**233,932**	**306,558**	**142,774**	**133,819**	**127,787**	**119,424**	**117,207**	**81,204**	**79,221**	**72,217**	**65,335**	**55,409**	**36,273**
Avg Monthly Customer Dollar Impact	**4.32**	**4.34**	**4.49**	**3.89**	**5.03**	**2.31**	**2.14**	**2.02**	**1.86**	**1.81**	**1.24**	**1.19**	**1.08**	**0.96**	**0.81**	**0.52**
Scenario 4 - Full-DR-CPP-Opt-20																
AMI Meter Installation Revenue Requirements	134,948	162,795	217,127	244,041	280,894	251,497	244,219	240,875	235,510	236,184	203,337	204,426	200,808	196,747	189,619	173,517
Stranded Cost Revenue Requirement - 5 year	117,522	112,959	104,084	72,591	127,088	-	-	-	-	-	-	-	-	-	-	-
Less:																
Expected O&M Reductions	(42)	(8,352)	(27,754)	(44,385)	(53,675)	(56,937)	(57,933)	(59,882)	(62,154)	(64,268)	(66,686)	(68,958)	(71,568)	(73,552)	(75,542)	(77,689)
Meter Revenue Requirement in Rates	(2,977)	(2,041)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)
Expected Procurement Reductions	(53)	(30,801)	(61,683)	(92,656)	(118,644)	(129,920)	(131,551)	(133,208)	(134,883)	(136,585)	(138,302)	(140,048)	(141,810)	(143,602)	(145,411)	(147,252)
Total Net AMI-related Rev Req Impact	**249,398**	**234,560**	**226,863**	**174,680**	**230,752**	**59,728**	**49,824**	**42,874**	**33,562**	**30,420**	**(6,563)**	**(9,490)**	**(17,481)**	**(25,318)**	**(36,246)**	**(56,335)**
Avg Monthly Customer Dollar Impact	**4.32**	**4.01**	**3.82**	**2.91**	**3.79**	**0.97**	**0.80**	**0.68**	**0.52**	**0.47**	**(0.10)**	**(0.14)**	**(0.26)**	**(0.37)**	**(0.53)**	**(0.81)**
Scenario 5 - Full-DR-CPP-Pure																
AMI Meter Installation Revenue Requirements	133,995	153,955	206,015	229,229	262,544	234,333	226,011	221,399	214,763	213,948	196,691	197,511	193,635	189,296	181,920	165,506
Stranded Cost Revenue Requirement - 5 year	117,522	112,959	104,084	72,591	127,088	-	-	-	-	-	-	-	-	-	-	-
Less:																
Expected O&M Reductions	(42)	(8,352)	(27,754)	(44,385)	(53,675)	(56,937)	(57,933)	(59,882)	(62,154)	(64,268)	(66,686)	(68,958)	(71,568)	(73,552)	(75,542)	(77,689)
Meter Revenue Requirement in Rates	(2,977)	(2,041)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)
Expected Procurement Reductions	(53)	(7,755)	(15,446)	(23,178)	(29,687)	(32,518)	(32,938)	(33,370)	(33,805)	(34,249)	(34,694)	(35,150)	(35,607)	(36,077)	(36,547)	(37,031)
Total Net AMI-related Rev Req Impact	**248,445**	**248,766**	**261,988**	**229,347**	**301,358**	**139,966**	**130,228**	**123,236**	**113,893**	**110,520**	**90,400**	**88,492**	**81,549**	**74,756**	**64,919**	**45,874**
Avg Monthly Customer Dollar Impact	**4.31**	**4.25**	**4.42**	**3.81**	**4.95**	**2.27**	**2.08**	**1.95**	**1.78**	**1.70**	**1.38**	**1.33**	**1.21**	**1.10**	**0.94**	**0.66**
Scenario 6 - Full-DR-CPP-FV																
AMI Meter Installation Revenue Requirements	133,995	153,955	206,015	229,229	262,544	234,333	226,011	221,399	214,763	213,948	196,691	197,511	193,635	189,296	181,920	165,506
Stranded Cost Revenue Requirement - 5 year	117,522	112,959	104,084	72,591	127,088	-	-	-	-	-	-	-	-	-	-	-
Less:																
Expected O&M Reductions	(42)	(8,352)	(27,754)	(44,385)	(53,675)	(56,937)	(57,933)	(59,882)	(62,154)	(64,268)	(66,686)	(68,958)	(71,568)	(73,552)	(75,542)	(77,689)
Meter Revenue Requirement in Rates	(2,977)	(2,041)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)
Expected Procurement Reductions	(53)	(7,614)	(15,144)	(22,718)	(29,115)	(31,909)	(32,326)	(32,754)	(33,184)	(33,625)	(34,066)	(34,518)	(34,972)	(35,438)	(35,905)	(36,385)
Total Net AMI-related Rev Req Impact	**248,445**	**248,907**	**262,290**	**229,807**	**301,931**	**140,575**	**130,841**	**123,852**	**114,514**	**111,144**	**91,028**	**89,123**	**82,184**	**75,395**	**65,561**	**46,520**
Avg Monthly Customer Dollar Impact	**4.31**	**4.25**	**4.42**	**3.82**	**4.96**	**2.28**	**2.09**	**1.96**	**1.79**	**1.71**	**1.39**	**1.34**	**1.22**	**1.11**	**0.95**	**0.67**
Scenario 7 - Full-DRR-CPP-F-20																
AMI Meter Installation Revenue Requirements	149,921	178,105	232,510	259,463	301,775	267,255	259,516	256,148	250,766	258,356	218,864	219,598	216,083	212,142	205,131	189,183
Stranded Cost Revenue Requirement - 5 year	117,522	112,959	104,084	72,591	127,088	-	-	-	-	-	-	-	-	-	-	-
Less:																
Expected O&M Reductions	(42)	(8,352)	(27,754)	(44,385)	(53,675)	(56,937)	(57,933)	(59,882)	(62,154)	(64,268)	(66,686)	(68,958)	(71,568)	(73,552)	(75,542)	(77,689)
Meter Revenue Requirement in Rates	(2,977)	(2,041)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)
Expected Procurement Reductions	(21,900)	(51,484)	(82,341)	(113,297)	(139,266)	(150,521)	(151,984)	(153,365)	(154,809)	(156,309)	(157,855)	(159,469)	(161,130)	(162,846)	(164,606)	(166,436)
Total Net AMI-related Rev Req Impact	**242,524**	**229,186**	**221,589**	**169,461**	**231,011**	**54,886**	**44,688**	**37,989**	**28,892**	**32,868**	**(10,588)**	**(13,740)**	**(21,526)**	**(29,166)**	**(39,929)**	**(59,853)**
Avg Monthly Customer Dollar Impact	**4.20**	**3.92**	**3.74**	**2.82**	**3.79**	**0.89**	**0.71**	**0.60**	**0.45**	**0.51**	**(0.16)**	**(0.21)**	**(0.32)**	**(0.43)**	**(0.58)**	**(0.86)**
Scenario 8 - Full-DRR-CPP-Pure																
AMI Meter Installation Revenue Requirements	163,136	188,849	243,445	269,296	310,318	279,108	264,225	259,304	252,477	258,374	237,356	237,825	234,049	229,831	222,564	206,289
Stranded Cost Revenue Requirement - 5 year	117,522	112,959	104,084	72,591	127,088	-	-	-	-	-	-	-	-	-	-	-
Less:																
Expected O&M Reductions	(42)	(8,352)	(27,754)	(44,385)	(53,675)	(56,937)	(57,933)	(59,882)	(62,154)	(64,268)	(66,686)	(68,958)	(71,568)	(73,552)	(75,542)	(77,689)
Meter Revenue Requirement in Rates	(2,977)	(2,041)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)
Expected Procurement Reductions	(26,167)	(43,969)	(62,734)	(80,331)	(95,610)	(106,201)	(110,175)	(110,474)	(110,817)	(111,210)	(111,615)	(112,070)	(112,563)	(113,077)	(113,627)	(114,198)
Total Net AMI-related Rev Req Impact	**251,471**	**247,446**	**252,130**	**212,260**	**283,210**	**111,058**	**91,206**	**84,037**	**74,595**	**77,985**	**54,143**	**51,886**	**45,007**	**38,291**	**28,484**	**9,491**
Avg Monthly Customer Dollar Impact	**4.36**	**4.23**	**4.25**	**3.53**	**4.65**	**1.80**	**1.46**	**1.33**	**1.16**	**1.20**	**0.83**	**0.78**	**0.67**	**0.56**	**0.41**	**0.14**
Scenario 9 - Full-DR-TOU-Opt-50																
AMI Meter Installation Revenue Requirements	136,114	168,554	217,230	240,418	272,920	243,355	235,500	231,407	225,318	225,103	203,039	204,080	200,451	196,310	189,128	172,931
Stranded Cost Revenue Requirement - 5 year	117,522	112,959	104,084	72,591	127,088	-	-	-	-	-	-	-	-	-	-	-
Less:																
Expected O&M Reductions	(42)	(8,352)	(27,754)	(44,385)	(53,675)	(56,937)	(57,933)	(59,882)	(62,154)	(64,268)	(66,686)	(68,958)	(71,568)	(73,552)	(75,542)	(77,689)
Meter Revenue Requirement in Rates	(2,977)	(2,041)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)
Expected Procurement Reductions	27,551	(4,149)	(19,879)	(29,600)	(37,996)	(43,240)	(46,752)	(37,395)	(38,223)	(39,101)	(39,957)	(40,802)	(41,645)	(42,490)	(43,335)	(44,278)
Total Net AMI-related Rev Req Impact	**278,168**	**266,971**	**268,770**	**234,113**	**303,426**	**138,268**	**125,903**	**129,219**	**120,030**	**116,823**	**91,485**	**89,409**	**82,327**	**75,358**	**65,340**	**46,052**
Avg Monthly Customer Dollar Impact	**4.82**	**4.56**	**4.53**	**3.89**	**4.98**	**2.24**	**2.01**	**2.04**	**1.87**	**1.80**	**1.39**	**1.35**	**1.23**	**1.11**	**0.95**	**0.66**
Scenario 10 - Full-DR-CPP-Opt-50																
AMI Meter Installation Revenue Requirements	136,114	168,926	217,946	241,465	274,324	244,789	236,983	232,960	226,929	226,787	204,784	205,903	202,342	198,286	191,177	175,079
Stranded Cost Revenue Requirement - 5 year	117,522	112,959	104,084	72,591	127,088	-	-	-	-	-	-	-	-	-	-	-
Less:																
Expected O&M Reductions	(42)	(8,352)	(27,754)	(44,385)	(53,675)	(56,937)	(57,933)	(59,882)	(62,154)	(64,268)	(66,686)	(68,958)	(71,568)	(73,552)	(75,542)	(77,689)
Meter Revenue Requirement in Rates	(2,977)	(2,041)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)
Expected Procurement Reductions	27,551	(8,391)	(28,380)	(42,232)	(54,060)	(60,707)	(64,258)	(54,918)	(66,491)	(67,641)	(68,807)	(69,991)	(71,189)	(72,399)	(73,628)	(74,968)
Total Net AMI-related Rev Req Impact	**278,168**	**263,101**	**260,986**	**222,529**	**288,766**	**122,234**	**109,881**	**113,249**	**93,373**	**89,966**	**64,380**	**62,043**	**54,674**	**47,424**	**37,096**	**17,510**
Avg Monthly Customer Dollar Impact	**4.82**	**4.50**	**4.40**	**3.70**	**4.74**	**1.98**	**1.76**	**1.79**	**1.46**	**1.39**	**0.98**	**0.93**	**0.81**	**0.70**	**0.54**	**0.25**
Scenario 11 - Full-DRR-CPP-F-50																
AMI Meter Installation Revenue Requirements	164,687	192,689	242,420	266,801	305,883	271,747	261,845	257,603	251,478	258,169	229,429	230,098	226,539	222,500	215,396	199,333
Stranded Cost Revenue Requirement - 5 year	117,522	112,959	104,084	72,591	127,088	-	-	-	-	-	-	-	-	-	-	-
Less:																
Expected O&M Reductions	(42)	(8,352)	(27,754)	(44,385)	(53,675)	(56,937)	(57,933)	(59,882)	(62,154)	(64,268)	(66,686)	(68,958)	(71,568)	(73,552)	(75,542)	(77,689)
Meter Revenue Requirement in Rates	(2,977)	(2,041)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)	(4,911)
Expected Procurement Reductions	7,336	(34,336)	(42,186)	(56,465)	(68,422)	(79,681)	(76,069)	(74,522)	(74,878)	(75,473)	(82,978)	(76,891)	(77,681)	(78,511)	(79,391)	(80,406)
Total Net AMI-related Rev Req Impact	**286,526**	**260,918**	**271,654**	**233,631**	**305,962**	**130,218**	**122,931**	**118,287**	**109,535**	**113,517**	**74,855**	**79,338**	**72,378**	**65,526**	**55,551**	**36,327**
Avg Monthly Customer Dollar Impact	**4.97**	**4.46**	**4.58**	**3.89**	**5.02**	**2.11**	**1.97**	**1.87**	**1.71**	**1.75**	**1.14**	**1.19**	**1.08**	**0.96**	**0.81**	**0.52**

Proceeding No.: R.02-06-001
Document No.: SCE-4

SOUTHERN CALIFORNIA EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

Advanced Metering Infrastructure Business Case Preliminary Analysis

Volume 4 – Preliminary Analysis of Partial Deployment Scenarios

Before the
Public Utilities Commission of the State of California

Rosemead, California
October 22, 2004

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PRELIMINARY ANALYSIS OF ADVANCED METERING INFRASTRUCTURE BUSINESS CASE

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I.

INTRODUCTION

The purpose of Volume 4 is to present our detailed preliminary business case analysis for each of the partial deployment scenarios identified in Attachment A of the Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure issued on July 21, 2004 (Ruling).

In Volume 2, we described our Business As Usual base case which, according to the Ruling, identifies the expected capital and maintenance costs we will incur associated with maintaining the current metering and communication systems for all customer classes, including any planned upgrades to metering and billing systems for the period 2006 to 2021. As stated in the Ruling, the Commission intends to use this base case information as the baseline for evaluating the cost effectiveness of the partial AMI deployment scenarios. Volume 3 provided the full deployment business case analysis required by the ruling.

The detailed preliminary business case analysis for each of the partial deployment scenarios required by the Ruling is addressed in Sections II through IV of this volume. Attachment A of the Ruling identified eight different partial deployment scenarios that the utilities are to analyze. Since we believe some of the required assumptions are improbable, especially with regard to customer acceptance of CPP rates, we have provided four additional scenarios with what we believe to be more reasonable assumptions. Recent market research studies showed approximately thirty-five percent of residential customers surveyed, "never give much thought to utilities until the water or power goes out".[1] Given the apparent

[1] ARD0075 Residential Segmentation: Southern California Edison Customer segmentation Research, December 2003.

apathy approximately one-third of our residential customers have toward their utility services, we feel it will be extremely difficult to implement the necessary behavioral changes many of the scenarios require. Thus, we are presenting detailed preliminary analysis with reduced customer participation expectations, for a total of 12 different partial deployment scenarios. Section II of this volume fully describes the expected impacts to our various business processes, operations and systems resulting from the partial deployment scenarios using the AMI technology solution discussed in Volume 2.

Based on those identified impacts, Section III and IV provide the detailed cost analysis in the Ruling's three major analytical categories (start-up and design; installation; and operations and maintenance) along with the five applicable cost categories[2] and seventy-nine individual cost codes associated with these cost categories. The benefit analysis is also provided in these sections by the four major benefit categories and forty individual benefit codes associated with these benefit categories. In addition, for those partial deployment scenarios addressed in Section IV, we provide a discussion of the risks and uncertainties that we have been able to identify for each of those scenarios. We also provide the net present value analysis for each partial deployment scenario in Section IV based on the costs and benefits identified in the cost and benefit categories.

Finally, Section V sets forth the preliminary Revenue Requirement and Rate Impact Analysis for each partial deployment scenario based on the detailed cost and benefits information provided in Section IV. A detailed cost recovery proposal will be part of our final analysis and formal application that will be filed later in this proceeding.

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[2] The Ruling specifies a sixth category for natural gas impacts. These costs are not applicable for SCE's business case analysis and thus, are not included.

II.

OVERVIEW OF PARTIAL DEPLOYMENT BUSINESS CASE

This section describes the impacts of a partial deployment of AMI on all of the various operations, processes and information technology systems throughout the company. For the purposes of the partial deployment analysis, we assume that the same RF technology solution described in Volume 2 will be used in both the full and partial deployment scenarios.

We envision two possible approaches for partial deployment. The first approach involves maximizing the existing Real Time Energy Meter (RTEM) investment through the mandatory use of Real-Time Pricing (RTP) for all customers with RTEM metering. Under this approach, all customers with demands over 200 kW that have RTEM metering would be placed on a RTP rate schedule. This approach would require very little additional capital because the vast majority of customers with demands over 200 kW already have the required interval data metering and thus, additional metering capital expenditures would only be required for new customers or replacement meters due to failure. Additional operation and maintenance costs for our various customer service and field operations and for information technology systems are expected to be minimal under this approach. This possible partial deployment approach is discussed further in Section III as Scenarios 12 and 13.

The second possible approach to partial deployment is based on the assumption that a partial deployment is best suited for a portion of our service territory where we can reasonably expect to realize the highest opportunity for load reduction and demand response capabilities and be geographically situated so as to result in significant meter reading savings. Thus, an appropriate portion of our service territory that met these two criteria is Climate Zone 4 as delineated in the

Statewide Pricing Pilot (SPP). This zone covers Baseline Regions 14 and 15 of our service territory. The primary reasons for adopting Zone 4 are discussed later in this section.

To help facilitate the Commission's understanding of the implications of partial deployment, the following sections describe the Zone 4 partial deployment case by its impact on our operations, using the Ruling's five applicable cost categories and four benefit categories in Attachment A as well as the cost and benefit codes identified in Appendix A in the Ruling. The impacts on our operations, processes and information technology systems described in the following sections apply to Scenarios 14 through 23 and do not apply to the System-wide implementation of RTP rates for the over 200 kW customers presented in Scenarios 12 and 13.

Zone 4 Selection

We selected Climate Zone 4 from the Statewide Pricing Pilot (SPP), which covers our Baseline Regions 14 and 15 for the reasons described below.

First, in order to maximize meter reading savings from a partial deployment, any such deployment must be geographically contained. Without a distinct geographical containment, the deployed AMI meter sites would be scattered and savings associated with meter reading reductions would not be realized.

Second, so as to maximize demand response from a partial deployment, we focused on those areas where customers have the highest potential for demand response. The Charles River Associates analysis of SPP results confirmed that the highest percentage reduction of peak-period energy use for critical peak pricing customers occurred in Climate Zone 4 of the SPP.[3]

[3] "Statewide Pricing Pilot Summer 2003 Impact Analysis", August 9, 2004, Charles River Associates, p. 83.

Third, it is imperative that a partial deployment be large enough to gain some economies of scale, but small enough that deployment risks can be more easily managed. We believe Zone 4 with about 450 thousand customers meets this criteria.

Finally, with the selection of Zone 4 for a partial deployment, there are benefits in terms of the IT and Communications infrastructure that need to be developed. Given that the geography of Zone 4 contains a mix of rural low density meters sites (such as those within the desert areas) and high density residential meter sites (such as those within the Palm Springs area), we will be able to better assess the actual capabilities and broad geographical coverage of the communications infrastructure. This first hand experience will be valuable and can be used in planning any future deployments. In addition, by deploying AMI on a smaller scale, we will be able to effectively test the end-to-end systems supporting the meter supply chain and interval data management without the additional inherent risks that would accompany any of the full deployment scenarios.

Overall, we expect approximately 438,000 meter sites will be able to provide reliable communications necessary for AMI deployment in a Zone 4 partial deployment. The Zone 4 meter sites are located within six of our service centers. The service centers involved are Palm Springs, Victorville, Antelope Valley, Redlands, San Jacinto, and Valencia.

The cost estimates described in the next section are based on the assumption that the Zone 4 deployment is completed in 2006 and that the required communications network is operational by July 2007. One significant difference between the Zone 4 partial deployment case and the full deployment case is our assumption regarding the actual percentage of "communicating" meters. Whereas we assumed ninety percent of full deployment meters would be capable of communicating successfully, this drops down to seventy percent in the partial deployment case. In the twenty percent opt-out demand response scenarios, the result would be that only eighty percent of the seventy percent communicating customer accounts would be able to actually participate on the default rate (*i.e.*, TOU or CPP). This was the assumption used for determining the level of demand response benefits; however, we may not have applied this lower participation rate consistently for all the cost estimates from the various operating organizations. Any such inconsistencies regarding the actual customer participation on the default rates will be resolved for the December filing.

A. Metering System Installation and Maintenance Category

This section describes the operations, processes and systems that are impacted by partial deployment for activities that fall under the meter system, installation and maintenance category. Under the partial deployment cases, this category in the Ruling involves our meter procurement, supply chain management, testing, installation and associated support activities.

1. Description of Meter System Installation and Maintenance Activities Impacted by Partial Deployment

The meter system installation and maintenance category involves all of our activities associated with meter procurement, supply chain management, testing, installation and other support. The impacts to these activities as a result of a Zone 4 partial deployment are described in detail in the following subsections.

a) Meter Procurement

As within the full deployment scenarios, we will procure five different types of meters for a partial AMI deployment based upon the service voltage and panel configurations we have in those areas. Although this deployment is on a much smaller scale, we will still need to modify many of our inventory activities to accommodate partial deployment since our current manual processes cannot accommodate the volumes expected under partial deployment. Specifically, we will automate our procurement and supply chain processes with the use of RFID technology.

b) Supply Chain Management

Currently, our Procurement and Material Management (PAMM) group receives, stocks, and distributes approximately 120,000 meters per year. Under partial deployment, PAMM will increase distribution to approximately 440,000 meters to support the initial deployment. In addition, it is estimated that there will be approximately 186,000 additional meters that will need to be processed from 2006 to 2021 due to meter replacements that result from failures in the field. The estimated number of meter failures by year end under partial deployment is shown in Table 4-1 below.

Table 4-1
Estimated Meter Failures by Year

Year	Estimated Meter Failures
2006	16,072
2007	42,511
2008	21,812
2009	13,003
2010	8,626
2011	8,594
2012	8,559
2013	8,523
2014	8,484
2015	8,444
2016	8,402
2017	8,358
2018	8,313
2019	8,266
2020	8,218

Given our prior experience with meter vendor reliability, we will maintain approximately three months worth of inventory in our distribution facility. Also, the distribution facility will need to begin stocking meters by the fourth quarter of 2005 so that PAMM can distribute to the various SCE locations to support deployment and installation beginning in January 2006.

Under partial deployment, PAMM will continue to deliver meters to the service centers one to two times a week so that materials are received on a just-in-time basis and thereby avoiding additional secure storage requirements. Additional personnel will be required in the service centers to process the meters as they are received. The meters are then stored in a secure area until the point they are scheduled for distribution. Due to the short-term nature of this project, we propose to use a Temporary Project Accountant position to process the meters at the service centers.[4] The Temporary Project Accountants will also be responsible for the distribution of the meters to the installers according to the installation schedule that will be developed. Once the installers replace the existing meter with the new AMI meter, the returned meters will be processed at the various service centers for salvage purposes.

c) **Meter Testing**

For residential meters, we plan to test 100 percent of the first two shipments of meters for quality assurance purposes. After that point, we will use a statistically significant sampling method to test the remaining meters. For commercial meters, we plan to test 100 percent of the first 10,000 commercial meters for quality assurance purposes. Similar to the residential meter testing, we

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[4] Use of this temporary position assumes that we will be able to secure IBEW approval for such a position.

plan to use a statistically significant sampling method for the remainder of these meters.

Meter testing will be conducted at our existing Meter Shop facility that will need to be reconfigured to handle the increased workload. Although partial deployment of AMI will decrease some of the existing meter test work, the workload will increase overall because of the scale and pace of partial deployment. As such, additional personnel will be required to handle this increased testing.

d) Meter Installation

(1) Residential and small commercial (less than 20 kW)

As discussed in detail in Volume 2, the communications network and information technology applications will not be operational until June 2007. Thus, we expect to continue our current meter reading and field service practices for all meters, even those that receive an AMI meter before June 2007.[5] We analyzed various methods to handle the AMI installations and continue our existing field work. Since partial deployment is short-term in nature, we determined that it would be more cost effective to hire temporary personnel rather than full-time personnel. The use of temporary resources depends on the assumption that we will receive IBEW concurrence to reactivate the project temporary meter reader job classification[6] and approve the creation of a project temporary installer job classification.

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[5] As described in Volume 2, Section II, in addition to manually read meters, SCE currently has more than 350,000 meters that are being read via van-based automated meter reading. As part of the RTEM project, SCE is collecting interval data on a daily basis from 12,000 commercial customers.

[6] IBEW approved the use of the Project Temporary Meter Reader job classification for the 2000 AMR deployment.

(2) Complex Meter Installations

Under a Zone 4 partial deployment, there are approximately 42,000 meters that we consider complex and therefore will be installed by our Meter Technicians who have specialty training. These complex meters are associated with Rate Schedule GS-2 and accounts with monthly demands above 20 kW. These also include 240v three-phase accounts and residential accounts with current transformers and potential transformers.

e) Support Related Costs

In order to support a partial AMI deployment, our field personnel will need to attend various training classes. As new meter readers are hired to backfill for those who have taken Project Temporary Installer positions, they will need to attend new hire meter reading classes. As existing Meter Readers transition to field service representative positions to backfill for those who have taken Project Temporary Installer positions, they will need to take classes on handling billing inquiries and using various customer service systems. Project Temporary Installers, who will handle the meter installations for the residential and less than 20 kW commercial accounts, will need to undergo a training program that covers Meter Installation Procedures and Practices as well as a class on how to use our Meter Tracking systems.

B. Communications Infrastructure

In a Zone 4 partial deployment, we will be utilizing the same radio frequency communications system as detailed in Volume 2. This system is comprised of collectors, packet routers, and MCC take-out points. Our AMI technology solution leverages our already-existing network and expands from there. New collectors will be mounted in the power space of a utility pole or streetlight and will communicate with the radios in the residential and less than 20 kW meters to transmit meter data throughout the network to the MCC take-out points. The meter technology for greater than 20 kW customers includes the use of a "radio under the meter cover" technology that will provide an RF "mesh-type" network of an additional 16,000 radios to the overall AMI communications network. Given the number of meters in partial deployment, we anticipate congestion on the communications network, particularly for those locations in close proximity to the MCC take-out points. The installation of a packet router will help ease this congestion and ensure that the data is transmitted to the SCE network in a timely manner so that it is available for bill calculation. The MCC take-out points need to be installed in order to collect the meter data and transmit it to SCE's computing network. Under partial deployment, we will need to supplement the 100 MCC take-out points we have in place today.

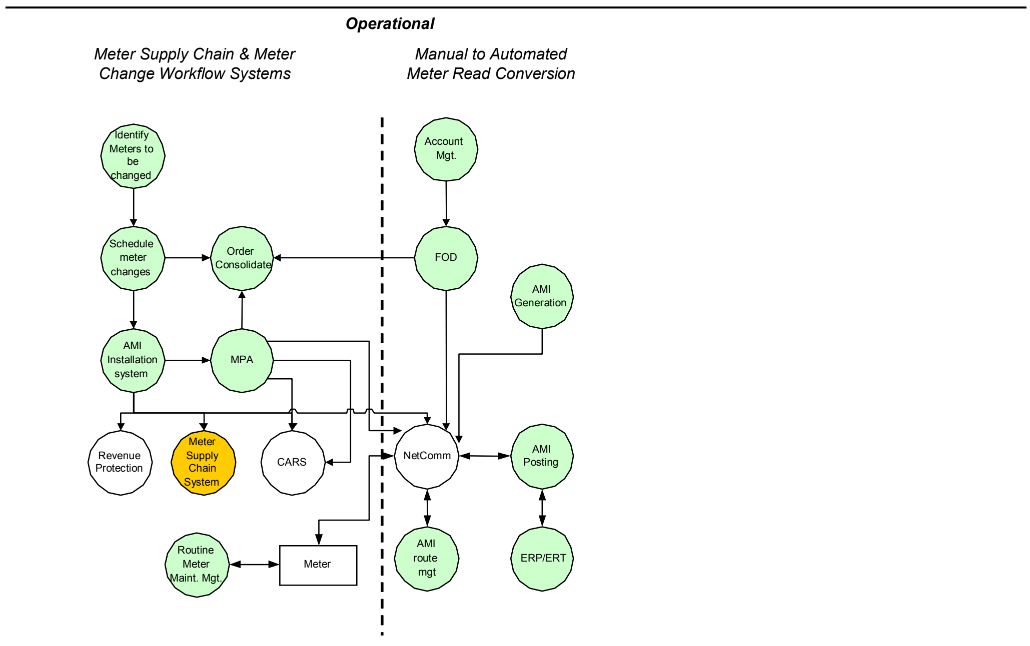
C. Information Technology Infrastructure

The information technology and application cost category captures the costs associated with applications and computer services. These activities are described in more detail in the sections that follow.

1. Applications

Under a Zone 4 partial deployment, we will need to enhance certain existing IT systems and/or develop new ones. Figure 4-1 illustrates the conceptual system architecture that will be required for partial deployment.

Figure 4-1
Partial Deployment IT Systems Architecture



The systems that need to be developed or enhanced to support partial deployment are in the operational areas of meter supply chain management, meter change workflow, and meter read conversion. The following subsections briefly describe each of these operational areas and the systems that will be developed or the enhancements that will be made to existing systems.

a) Meter Supply Chain Management

We will need to make changes to the Meter Supply Chain (MSC) system so that the following procurement processes can be automated under partial deployment:

- Order and delivery tracking from the meter vendor

- Verifying receipt of the meters and reconciliation with the order
- Logging the meter as an SCE asset
- Testing of new meters
- Distribution of meters from the Warehouse to Service Centers for installation

Each pallet of meters received from the vendor will be equipped with Radio Frequency Identification (RFID) tags. Upon receipt of the meters in SCE's warehouse, the RFID tags on the meters and pallets will be "read" into the system to verify and reconcile the order. RFID tags on individual meters will transmit unique asset identifications into the MSC system to track meters throughout the entire deployment workflow. The MSC system will register meters as SCE assets and manage the distribution of the meters to our service centers for installation.

The MSC system will also be capable of interfacing with several related systems. For example, the MSC system will interface with the AMI Installation system, described below, to pass meter delivery information automatically to the service centers. Further, MSC system will interface with SCE's general ledger system to record new and retired asset information as meters are replaced and installed during partial deployment.

b) <u>Meter Change Workflow Systems</u>

As shown in Figure 1 above, a number of new IT systems will be needed to handle the meter change workflow in the areas of:

- New Meter Identification
- Meter Changes Order Scheduling
- AMI Installation

- Meter Order Consolidation
- Meter Process Automation

First, a new system will be needed to identify the meters that that will require a change to the new AMI metering. This application will have the functionality to identify sites by location where the AMI meters need to be installed. The application will interface with the MSC system to identify the exact meters to be installed at a particular site.

In addition, partial deployment will require development of a new system to track and schedule meter change orders. Our current Meter Process Automation (MPA) system that handles meter change requests at an individual meter site level and could not handle the significant volume of meters involved in a full deployment. Therefore, a new system would be required to handle the significant volume of meter changes associated with partial deployment. The new Scheduling Meter Change (SMC) system will need to interface with the new AMI Route Management system that verifies all meters for a route are, in fact, ready for AMI integration. The SMC also automates the switching to the AMI network. It will need to interface with the current Customer Data Acquisition Management system which maintains the route information. Building this interface will ensure that the SMC system efficiently schedules meter change orders. The new SMC system will also be used to track planning activities (*e.g.* city or field inspections) related to AMI meter installation. This system will have the ability to issue and cancel orders, and to schedule appointments or reprioritize orders as field conditions warrant.

A Zone 4 partial deployment will also require a new system to handle the collection of necessary meter information to properly route the meter installation request to the field personnel installing the AMI meter. The AMI Installation (AMI-I) system will provide the field personnel with the route information necessary to locate the meters that will be changed. As meter removals and installations are completed by the field personnel, the AMI-I system will process completion information, including Global Positioning Satellite (GPS) data, and deliver it to the Meter Inventory system for further processing.

The AMI-I system will also interface with the SMC system to reschedule orders that were not completed. The system will also generate various exception situations that will require special processing. An order download/upload process will be built to perform interface functions between the host mainframe system and the Field Tool system. The users of the Field Tool will have the capability to view orders and input completion information. The Field Tool will also have the flexibility to allow users to cancel or refer orders, if appropriate.

Under a Zone 4 partial deployment, a new system is required to interface with the existing MPA system which currently can schedule, track and post data on meter orders. The Order Consolidation (OC) system will be developed to examine various meter orders for the same installed service account to consolidate them and maximize operational efficiency.

To accommodate a Zone 4 partial deployment, we expect to make enhancements to the existing MPA system that is used to schedule, track and post data related to meter orders. Enhancements are necessary because the current MPA system is not capable of managing the meter volumes expected in partial deployment. An interface to the new AMI-I system will be required to provide a link between the existing and new systems. In addition, enhancements are required so that the MPA system can store GPS data returned from the field to facilitate meter location tracking.

c) Meter Read Conversion

As shown in Figure 4-1 above, under a Zone 4 partial deployment, a number of new systems need to be developed to handle the AMI process. Additionally, enhancements to existing meter-related systems are required.

As a result of partial deployment, we expect that enhancements to the current Account Management (AM) system will be required. The AM system is responsible for the various administration and maintenance activities associated with each customer's account. For partial deployment, user functions will need to be modified to handle interval data usage. As an example, the "Bill Correction" function will need to be changed so that users have the ability to input interval data usage in situations where the data is not available for certain periods of time. Another example involves changing the data validations and prorating algorithms to handle interval data usage.

We also expect enhancements will be needed to the current Field Order Dispatch (FOD) system to accommodate partial deployment. The FOD system is currently responsible for the management of field visits related to metering and communications incidents that may include error detection, failures and replacements. New enhancements will need to be developed to route field events from FOD to the AMI communications network support group and meter support groups.

A Zone 4 partial deployment will also require a new system to monitor the status of accounts on each of the routes to determine when all of the installed AMI meters on a particular route are communicating with the network. Once the new AMI Route Management system has validated that all newly installed AMI meters on a route are successfully communicating with the network, the route can then be switched to an AMI route.

We expect partial deployment to require a new system to generate requests for meter reads from the communications network. An AMI Generation system will be developed to identify and generate accounts that are scheduled to be billed on any particular day. Based upon this data, the AMI Generation system will create requests for the network to gather meter data from these accounts so that bills can be prepared.

Under a Zone 4 partial deployment, a new system is needed to collect meter read information from the communications network, validate the data, and post the data in the Customer Service System (CSS) meter reading tables. If the data fails certain validations, the new AMI Posting system will generate a new exception to be included in the CSS exception table.

We anticipate that partial deployment will require enhancements to the existing Exception Reporting and Routing (ERR) system, which is responsible for reporting, routing, and handling various exceptions. Enhancements will be made to the ERR system so that non-communicating equipment (meters, collectors, *etc*.) will be reported to the ERR system from the communications network through an electronic file. In addition, enhancements for the ERR system will be developed to address new exceptions created by AMI processes. If exceptions cannot be resolved automatically by the ERR system, they will be routed to a bookkeeper for resolution.

Each of the new or enhanced systems represented in Figure 4-1 require computing services infrastructure to support the software handling the partial deployment AMI data. Computing Services includes the actual procurement and installation of the necessary infrastructure. Computing Services infrastructure and hardware fall into the following broad areas:

- Additional servers
- Additional processors to increase MIPS on the mainframe

- Additional processors to increase processing capacity on RISC and Wintel systems
- RFID tag reading equipment
- Additional Laptop and Desktop computers
- Additional Storage (DASD)
- Incremental personnel to manage installation of additional infrastructure
- Additional operating system and database licenses
- Computer network upgrades

D. <u>Customer Service Systems Category</u>

This section describes the operations, processes and systems that are impacted by partial AMI deployment. These are needed to provide an adequate level of customer services essential to the efficient installation and operations of a Zone 4 partial deployment of the AMI infrastructure. Specifically, the customer services discussed in this section include Billing, Call Center, Meter Order Processing, and Customer Communications (Marketing) activities. This section will not include meter reading and field services costs, because these functions are essential to the Meter System Installation and Maintenance costs discussed in prior sections.

1. <u>Description of Billing Activities Impacted by Partial Deployment</u>

SCE's Billing Organization currently processes and delivers over fifty-six million customer billing statements each year. For the most part, this process is highly automated and only a small percentage of the total bills produced require manual intervention. Historically, the two situations having the largest impact on the manual billing processes are meter changes and rate structure changes, both of which play a significant role in the partial deployment of AMI. Under the partial deployment scenario, we expect that we will need to supplement the existing billing system that depends primarily on manual reads in the field, with a system that can generate a bill based on the AMI data transmitted through the network communications infrastructure. Billing Operations will also be impacted due to the incremental change out of an additional 186,000 meters throughout the fifteen-year analysis period, due to anticipated AMI meter/communication failures (*see* Table 4-1 above).

Under the partial deployment operational-only case we assume that we will read the vast majority of meters remotely only once per month and that there is no need for interval data beyond that which is being collected today. Thus, our processes associated with aggregating, validating, and processing interval data are not impacted in the partial deployment operational-only scenario. As will be seen, the processing of interval data in several of the other scenarios has a significant impact on billing costs. This will be particularly evident in the demand-response scenarios where the majority of Zone 4 accounts will require interval data processing in order to determine consumption and demand readings by time period and/or during critical peak periods. The processing of interval usage data is vastly more complex than simple monthly meter reads and requires an additional layer of validations and the resultant exception processing in order to assure the integrity of each fifteen-minute or hourly read. For the operational-only case, we expect the need for approximately eleven FTEs in 2006 and 2007, dropping down to nine by 2010 as installations are complete and meter failure rates decrease to a steady rate of two percent per year. For the demand response cases, these numbers increase significantly, going from approximately twenty-five FTEs initially, peaking at thirty-eight to forty FTEs (depending on the scenario), and dropping to approximately twenty as operations reach a steady state.

Billing related start-up costs are associated with the specification of security systems, the development of data retrieval strategies, network planning, and the meter RFP proposal specifications. The largest partial deployment impact on the Billing Organization operations and processes occurs during the installation phase and, as previously discussed, is attributable to the mass exception processing that is expected to occur as meters are changed out. A small percentage of the changed meters will result in billing related problems (exceptions) requiring manual processing to assure timely and accurate billing. Though small in terms of percentage of the total, the initial change-out of nearly 0.5 million meters will result in a significant increase in the number of billing exceptions being processed.

A major contributor to the increased exception processing is the anticipated failure rate of AMI meters we expect will occur in the initial stages of partial deployment. When a meter fails in the middle of a billing period, a determination must be made as to how the affected bill (and subsequent bills) will be processed. This process becomes considerably more complex when the affected account depends on the accuracy of interval consumption data. Depending on the nature of the meter failure, a judgment call is often required with regard to estimating consumption. This sometimes involves contacting the customer in order to assure a fair and equitable resolution. A similar process is followed when rate-related billing exceptions occur.

We estimate that fifty percent of all meter failures will require exception processing within the Billing Organization. Meter failures are expected to peak at 42,500 in 2007, and drop to a level of 8,600 by 2011. We expect that beyond the initial installation phase, meter failures will continue at a steady state rate of approximately two percent through their useful service lives.

Another contributing factor to billing installation impacts is related to the development of new validation routines to replace the validations that currently take place in the field as meters are being read manually. Reading meters remotely adds a whole new layer of data quality concerns, not only attributable to new meter technology, but to the likelihood of communication system failures which will inevitably occur. This is based on our experience not only with the recent implementation of RTEM, but from our earlier experience in deploying 350,000 van-based AMR meters.

Overall, under partial deployment, we expect a slight improvement in metering accuracy. We also expect higher meter failure rates and that we will experience the loss of field validations.

2. Description of Call Center Activities Impacted by Partial AMI Deployment

Our Call Center receives and handles over eleven million calls per year. Partial deployment of AMI is expected to result in call volume increases ranging from a low of approximately 20,000 calls for the initial year of the operational-only scenario to a high of approximately 245,000 calls during the peak installation phase for certain demand response scenarios. The call volume increases result from customers calling to inquire about the new meter that has been installed to questions about opting out of the new rate in the demand response partial deployment scenarios. For analytical purposes, the call volume estimate includes the number of customers who will opt out in addition to a number of customers who will call to inquire about opting out, but choose to stay on the new rate. In determining the impacts on the Call Center due to partial deployment, we estimated that seventy percent of the customers that called would actually opt out. This estimate is based on our assumption that most customers who call to opt out will have already made up their mind, however, with proper training of Call Center personnel, we feel we should be able to convince thirty percent of such callers to stick with the program.

We expect that as AMI is deployed and operational, call volume reductions will result from more accurate billing. Billing inquiries today are received for several reasons, one of which is an inaccurate meter read. Based on a study using 2003 data, 22,791 calls were a result of meter reading errors. We used this number as a percentage of all calls to determine the percent of billing inquiry calls we could expect from Zone 4 that would be projected as having been the result of meter read errors. For the business case, we assumed that 100 percent of these calls from Zone 4 would be avoided with automated meter reads. Ultimately, we expect call volume will be reduced by approximately 2,200 calls per year for all partial deployment scenarios.

E. Management and Miscellaneous Other

This section describes the overall Project Management and miscellaneous "other" costs not previously identified. Other costs include centralized training costs, personnel recruiting costs, employee communications, and miscellaneous start-up costs. For the most part, these costs fall into the "start-up" and "installation" categories. The Billing Organization has identified some on going O&M management costs that are expected to continue through the duration of the analysis period.

1. Project Management

For the partial deployment scenarios, a project management team consisting of three middle management and two staff support personnel will oversee the two and one-half year installation phase. In addition, each of the major operating departments has estimated some project management costs to support the core project management team.

2. Training Costs

Training costs would be incurred within each of the major operating organizations as well as at the corporate level within our centralized Job Skills Training (JST) Organization. Incremental training costs will be incurred not only for specialized instruction related to AMI metering activities and new rate options, but a significant part of the increased training cost will be more generalized, new-employee training. Our JST training includes the cost for development of the curriculum, preparation of the training materials and paying the instructors. JST training is primarily for new employees in the Meter Reading, Call Center and Billing Organizations that will be needed to meet the added workload during the installation phase of AMI. These costs do not include paying the employees themselves for the "seat-time" spent in training sessions. Seat-time costs are included in the cost estimates for each individual operating organization.

3. Customer Communications

Under the "operational-only" partial deployment scenarios, we expect only a minimum level of direct customer communications costs beyond what we currently experience. We are required to notify customers of planned meter changes and we expect to comply through a regular monthly bill insert or bill message. Any mass media or other outbound communications that the Commission may feel is needed for purposes of public notification under the operational-only scenario would add incrementally to our estimated costs.

The costs associated with the addition of demand response options under the partial deployment scenario will differ based on scenario, but the basic structure and approach to the media and information delivery campaign will be similar. The strategic approach of the campaign is to utilize an integrated mix of media designed to affect a long-term cultural and behavioral change. The campaign must be multi-year in order to positively affect long-term change. There are three tenants of the campaign: 1) raise awareness and educate customers about the program and its benefits as well as the behavioral changes required to comply with each specific demand response option, 2) develop and implement a strong and comprehensive acquisition effort to recruit customers and meet participation rate expectations, and 3) develop and implement a vigorous retention campaign to maintain the customer base over time. The media mix includes:

- Mass Media: Television, radio, and print for education and awareness;
- Targeted/Ethnic Media: Local print, cable television, and strategic partnerships (ethnic business chamber promotion) including the use of in-language media;
- Direct Communications: Bill inserts, direct mail, e-mail notification, face-to-face communication through the account management function;
- "CPP Day" Notification: Use of phone banks, radio, public service announcements, and press releases/press relations to notify customers of demand response events.

Each cost category includes a basic level of communication and outreach that is designed to reach 100 percent of our Zone 4 customers, and saturate the customer base with broad-based educational and customer-specific behavioral change information. In addition to the messages contained in the campaign, each partial deployment demand response scenario will require extensive research to understand consumer attitudes and to adapt messaging appropriately for all geographic and ethnic groups prior to the delivery of the campaign.

The campaign will differ significantly from other SCE campaigns previously undertaken, which are designed to create customer awareness and promote programs on a short-term basis. This campaign will create customer awareness and education about behavioral changes required to comply with the chosen demand response option, with long-term behavioral and cultural change being essential to the program's success. One of the two main objectives of the campaign is to condition customers to understand why demand response requires a behavioral change and move them to change their behavior. Through education, we expect to achieve customers' understanding of their energy usage and the impacts time-differentiated pricing options have on overall costs. This will be achieved through the customer-specific education portions of the campaign. The other main objective of the campaign is to recruit and retain customers on these demand response rate programs over time. This will be accomplished through the customer-specific acquisition and retention portions of the campaign.

The cost of the campaign is affected by our location and the customer base we serve. The greater Los Angeles area is the second largest and highest cost media market in the country, and is also very diverse both linguistically and culturally.[7] Because of this diversity, messages must be created and delivered using languages other than English. Additionally, thirty-five percent of SCE's customer base has demonstrated their lack of interest in electricity issues other than when their power goes out.[8] Customer communications must break through this demonstrated low level of interest and be accomplished through a variety of linguistically and culturally appropriate approaches to properly address the various Asian, Spanish, and African American cultures and dialects well as the general population.

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[7] 2003 – 2004 Nielson Universe Estimates, DMA Ranking and Advertising Age Magazine, July 24, 2000.

[8] ARD0075 Residential Segmentation: Southern California Edison Customer segmentation Research, December 2003.

4. Other Costs

This cost category includes other areas where some miscellaneous costs have been identified such as overseeing the vendor RFP process, contracts supervision, employee communications costs and personnel recruiting, and employee training and communications relating to customers' access to their own energy usage data. Other management overhead costs that span across two or more functional cost categories, such as project management and the administration of job skills training are also included in this cost category.

III.

PARTIAL AMI DEPLOYMENT BUSINESS CASE ANALYSIS FOR 200 KW + CUSTOMERS

The Ruling requires the analysis of large commercial and industrial customers (>200 kW) placed on a default basis to a two-part real time tariff, and customers may elect to switch to their current applicable TOU tariff. We considered this scenario, but provide an alternate approach in its stead for the following reasons. First, by memo dated August 6, 2004, Agency staff acknowledged that a two-part RTP rate for California utilities has not been developed and as an alternative suggested that utility analysts use data provided in findings from two reports on RTP tariffs, one from a study in Georgia and the other from a study in New York. We used the study from Georgia by Christenson Associates[9] as a basis for estimating demand response from RTP segmented by Standard Industrial Classification (SIC) code. Our approach for estimating the demand response for RTP using this study is explained in Volume 2 of this filing.

Second, we have no reasonable data available for estimating an opt-out percentage that would result from the implementation of the RTP tariff on a default basis. The largest customers in this group are relatively sophisticated and will evaluate and affirmatively choose whichever rate is most beneficial to them. Hence, implementation of the RTP tariff on a default basis may not be as effective for this customer class as it would be for small customers. Alternatively, for the purpose of the analysis we assume that RTP would be implemented on a mandatory basis. This provides the maximum customer participation and highest demand response benefit.

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[9] "Potential Impact of Real Time Pricing in California," by Steve Braithwait and David Armstrong, Christensen Associates, January 14, 2004.

We made additional adjustments to the study of large customers placed on an RTP tariff. The Ruling required that the large customer analysis be combined with Scenarios 4 and 7 but we have kept the analysis as a separate scenario so it could be added to any of the full or partial AMI deployment scenarios. Moreover, we analyzed two variations of RTP deployment. In Scenario 12, we assume that all large customers with RTEM meters are placed on a RTP rate on a mandatory basis. For Scenario 13, we assume that our current Schedule I-6 interruptible program is maintained and all other large customers are placed on a RTP rate. Thus, Scenario 12 is a study of large customers on an RTP rate and Scenario 13 evaluates the mandatory implementation of RTP plus reliability provided by Schedule I-6.

A. <u>Operational Costs</u>

For Scenarios 12 and 13, we expect to incur certain information technology infrastructure costs that we have preliminarily estimated at $0.3 million for each scenario in costs codes C-3, C-4, C-10 and I-1. In addition, we expect to incur customer education and marketing costs for those customers taking advantage of the default two-part RTP rate schedules. For this preliminary analysis, we estimate these costs at $17.5 million for both scenarios in cost codes CU-10 and M-14. We will continue to refine our preliminary estimates for the costs and reflect these refinements in our final showing as appropriate.

The only difference between Scenarios 12 and 13 pertain to expected customer acquisition costs for the rate incentives that would be paid to Rate Schedule I-6 customers. For this preliminary analysis, we forecast costs of approximately $355.5 million. We will also continue to refine this preliminary estimate and will reflect these refinements in our final showing, as appropriate.[10]

Table 4-2
Summary of Costs for Scenarios 12 and 13
(000s in 2004 Pre-Tax Present Value Dollars)

	Scenario 12	**Scenario 13**
Cost Categories	**Total**	**Total**
Metering System Infrastructure	$0	$0
Communications Infrastructure	0	0
Information Technology Infrastructure	327	327
Customer Service Systems	0	0
Management and Miscellaneous Other	17,500	17,500
Rate Incentives for Schedule I-6		355,500
TOTAL:	$17,827	$373,327

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. We believe such an adjustment would apply, however, we would require additional information about the actual RTP rates to employ our methodology as presented in Volume 2, Appendix C.

B. Benefits For Scenarios 12 and 13

Scenarios 12 evaluates the demand response benefits of RTP for all large C&I customers above 200 kW. Scenario 13 evaluates the demand response benefits of RTP for all large C&I customers above 200 kW plus the reliability benefits of maintaining Schedule I-6 customers. Our methodology for estimating demand reductions for these scenarios is discussed in Volume 2.

[10] In preparing this preliminary analysis, we discovered that we inadvertently included the rate incentive customer acquisition costs in cost code I-6 rather than cost code M-14. We will reflect this change in our final showing.

Table 4-3 Summary of Benefits for Scenario 12 (Millions in 2004 Pre-Tax Present Value Dollars)		
	Scenario 12	**Scenario 13**
Benefit Categories	**Total**	**Total**
Systems Operations Benefits	$0	$0
Customer Service Benefits	$0	$0
Management and Other Benefits	$0	$0
Demand Response Benefit DR-1, RTP Customers	$228	$116
Demand Response Benefit DR-1, Schedule I-6 Customers	n/a	$336
Demand Response Benefit DR-2	$34	$50
TOTAL:	$264	$502

C. <u>Uncertainty and Risk Analysis</u>

No risk analysis of cost or operational benefit was performed for these scenarios as the costs and associated risks are relatively low given our knowledge of the existing system and that no incremental operational benefits were identified.

The load reductions from RTP are untested in recent years in SCE territory and therefore unknown. Also, we did not examine potential rate design issues associated with RTP. No market-based real-time prices exist in California so an RTP rate would have to be based on a proxy of market prices or actual real-time costs to the utility. We also do not know how customers would react to mandatory RTP. The literature indicates that, while some large customers can adjust usage, others cannot.

D. <u>Net Present Value Analysis</u>

Table 4-4 summarizes the Net Present Analysis for Scenario 12.

Table 4-4 Summary of Cost/Benefit Analysis for Scenario 12 ($Millions)				
Costs	**Benefits**	**Pre-tax PV**	**After Tax NPV**	**Rev. Req. NPV**
$17.9	$237.9	$220.0	$130.7	$219.7

Table 4-5 Summary of Cost/Benefit Analysis for Scenario 13 ($Millions)				
Costs	**Benefits**	**Pre-tax PV**	**After Tax NPV**	**Rev. Req. NPV**
$373.3	$469.7	$96.4	$57.2	$91.9

As shown in Tables 4-4 and 4-5, Scenarios 12 and 13 analysis results in positive NPVs of $219.7 million and $91.9 million, respectively. These scenarios derive their positive value by obtaining demand response benefits with no incremental meter deployment costs.

IV.

PARTIAL AMI DEPLOYMENT BUSINESS CASE ANALYSIS FOR ZONE 4 OPTION

This section provides our second approach to partial AMI deployment to approximately 440,000 customers in climate Zone 4 as delineated in the SPP. Our objective in analyzing these partial deployment scenarios is to determine the best-case cost/benefit results by selecting a portion of our service territory where we can reasonably expect to realize the highest opportunity for load reduction and demand response capabilities and be geographically situated so as to benefit from significant meter reading savings. Climate Zone 4 is a portion of our service territory that met these two criteria. This zone covers Baseline Regions 14 and 15 of our service territory. The primary reasons for adopting Zone 4 were discussed earlier in Section II.

The following sections will address the eight separate partial deployment scenarios required by the Ruling, in addition to two partial deployment scenarios which we feel more realistically reflect customer participation assumptions for certain demand response and reliability scenarios. Table 4-6 below identifies the partial deployment scenarios for which we are providing preliminary analysis.

Table 4-6 Listing of Partial Deployment (Zone 4) Scenarios	
Scenario No.	Description
14	Partial AMI: Climate Zone (Zone 4) - operational only case
15	Same as Scenario 14 except includes outsourcing
16	Partial AMI: Zone 4 – TOU tariff is default
17	Partial AMI: Zone 4 – CPP-F tariff is default for residential, CPP-V default for small C&I, no large C&I customers included
18	Partial AMI: Zone 4 – Current tariff with opt-in to CPP-Pure tariff (residential and small C&I)
19	Partial AMI: Zone 4 – Current tariff with opt-in to CPP-F residential/CPP-V small C&I
20	Partial AMI: Zone 4 – Current tariff with opt-in to CPP Pure
21	Partial AMI: Zone 4 – Current tariff with opt-in to CPP-F residential/CPP-V small C&I
22	Same as scenario 16 with certain SCE recommended alternative assumptions
23	Same as scenario 17 with certain SCE recommended alternative assumptions

The following subsections describe the costs and benefits we expect will result from implementing each respective scenario. These costs and benefits are described as "incremental" to our "Business As Usual" case, as presented in Section II, B of Volume 2. "Partial Deployment" means changing out ninety-seven percent of the 450,000 existing Zone 4 meters over a two-year time period, and building the communications infrastructure to allow us to read seventy percent of these meters automatically.

A. Scenario 14: Operational Only - Utility Implemented

In this subsection we describe the operational costs and benefits we expect will result from partial deployment to Zone 4 by SCE of the AMI metering and communications infrastructure, quantified using the Ruling's cost and benefit codes. We also present a discussion of the uncertainties and risk analysis for this scenario, as well as a discussion of the net present value analysis. As required by the Ruling, "this scenario assumes that no new tariffs are established as a result of the full deployment of AMI, so costs and benefits that derive from the rollout of new tariffs are excluded in this case."[11] The operational activities processes and procedures impacted by full deployment under this particular scenario were fully discussed in Section II above.

1. Costs

Appendix A of the Ruling classifies AMI deployment costs into six broad cost categories: Meter System Installation and Maintenance, Communication Systems, Information Technology and Applications, Customer Services, Management and Other, and gas service costs (which are not applicable in any of SCE's scenarios). Table 4-7 below summarizes our estimated costs for Scenario 14 in the five cost categories.

Table 4-7
Summary of Costs for Scenario 14
(000s in 2004 Pre-Tax Present Value Dollars)

Cost Categories	Total
Metering System Infrastructure	$84,579
Communications Infrastructure	5,547
Information Technology Infrastructure	54,188
Customer Service Systems	8,164
Management and Miscellaneous Other	9,415
TOTAL:	$161,894

The following subsections provide our preliminary analysis of these cost categories along with the unique cost codes within each cost category.

[11] Ruling, Attachment A, p. 7.

a) Meter System Installation and Maintenance

(1) Start-up and Design

Appendix A to the Ruling does not identify any cost codes for meter system start-up or design. As such, all Meter System start-up or design activities have been classified as an installation cost below.

(2) Installation and Maintenance [MS-1 through MS-11]

The cost categories of MS-1 through MS-11 correspond to the costs associated with procurement, supply chain management, testing, installation and associated support costs. The following sections describe the costs associated with each of those areas in more specific detail.

(a) Meter Reader Transition Costs (MS-1)

Residential and Small Commercial (< 20 kW) Meters

We are assuming that our current field services representatives and meter readers will be selected for the project temporary installer positions, as discussed further in cost category MS-5. In the beginning of 2006, we estimate that we will have seventy-six vacancies in our meter reading staff caused by employee movement to other areas to support AMI deployment. We plan to backfill those vacancies in early 2006.

As discussed in Scenario 1, when backfilling these positions, we have taken into account the productivity differential between a new meter reader and an experienced meter reader. As such, in addition to the seventy-six vacancies that will be filled, we will need to hire an additional twenty-four project temporary meter readers in 2006. Given our typical attrition rate of thirty-five percent, we estimate that twenty-four FTEs will attrition out of the organization by the end of 2006. The anticipated cost is $1.63 million in 2006.

For the meters in Zone 4 that are handled by our rural service center personnel, we will rely on our existing Field Service Representatives (FSRs) to handle the 75,640 installations. Existing meter readers will be upgraded and trained to handle the FSR job responsibilities to backfill for the FSRs taking the project temporary installers positions. We plan to backfill the vacancies in our meter reading staff with project temporary meter readers. We estimate that we will need eighteen meter readers in 2006.[12]

(b) Supervision of Installer Workforce (MS-2)

With the addition of new staff (discussed in the cost category descriptions for MS-1, MS-5, and MS-12), we will need to hire additional supervisors and support personnel. We forecast a need to hire an additional supervisor and Supervising Field Service Representative for each of the three major service centers involved in the deployment. We will also add three additional FTEs to handle revenue protection activities (discussed in the cost category description for MS-12). We also expect to hire one FTE to provide support with deployment tracking and reporting. Overall, these ten incremental FTEs are estimated to cost $1.3 million.[13]

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[12] Upon compiling the filing of our preliminary analysis, we discovered an error associated with the cost calculation for this cost code and the overall estimate will be revised accordingly in our formal application as necessary.

[13] Upon compiling the filing of our preliminary analysis, we discovered an error associated with the cost calculation for this cost code and the overall estimate will be revised accordingly in our formal application as necessary.

(c) Cost of Purchasing Meters (MS-3)

Our preliminary estimate is that we will procure approximately 659,000 meters at a cost of $52.1 million over the 2006 to 2021 timeframe.[14] We will procure five different meter types for the AMI deployment. Each meter will be equipped with an RFID tag to facilitate our procurement and supply chain processes. Sales tax was added to the meter cost.

We will procure over 438,000 meters in order to replace the existing meters installed in the Zone 4 area. Table 4-8 shows the types of meters, quantities, and prices that will be procured for partial deployment.

Table 4-8
Meters, Quantities and Prices in Partial Deployment

Meter Type With Communication Module	Amount	Base Cost	RFID Cost
< 20 kW residential single phase	386,827	$50	$2
Residential single phase transformer rated	4,018	$50	$2
< 20 kW residential network	9,228	$130	$2
< 20 kW commercial	27,595	$320	$2
> 20 kW commercial	10,456	$700	$2

As discussed in Scenario 1, in addition to the cost estimates in Table 4-8, we will incur additional costs for meter lock rings and adapters.

Our preliminary analysis shows that during the partial deployment, we will have meters that fail after the three-year warranty period has expired. We estimate that there will be approximately 108,000 meter

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[14] Upon compiling the filing, we discovered that our cost estimates are based upon procuring approximately 700,000 meters. In December, we will update our cost estimates to reflect procuring 659,000 meters.

failures during the 2009 to 2021 timeframe based on our projected failure rate.[15] In those cases, we will need to procure and install new AMI meters at these meter sites. Table 4-9 illustrates the expected meter type and volumes associated with replacing these failed meters.

Table 4-9 **Cost Table for Meter Failures Out of Warranty Purchases Only 2009 Through 2021**	
Meter Type With Communication Module	**Quantity**
< 20 kW residential single phase	96,109
Resdential single phase - transformer rated	994
< 20 kW residential network	2,293
< 20 kW commercial	6,827
> 20 kW commercial	2,587
TOTAL	108,810

In addition to installing AMI meters on existing meter sites, we will need to install AMI meters as we experience customer growth. We estimate approximately 0.11 million new meter sets during the 2006 to 2021 timeframe due to customer growth. Table 4-10 shows the expected meter type and volumes associated with these new meter sets.

[15] *See* Volume 2, Section III concerning how this failure rate was calculated.

Table 4-10 Cost Table for Growth Meter Purchases Only 2006 Through 2021	
Meter Type With Communication Module	**Quantity**
< 20 kW residential single phase	94,076
Residential single phase - transformer rated	1,491
< 20 kW residential network	2,244
< 20 kW commercial	10,243
> 20 kW commercial	3,881
TOTAL	111,935

(d) Installation and Testing Equipment Costs (MS-4)

In 2006, we estimate that we will incur costs for tools, equipment, materials, supplies, uniforms and vehicle costs associated with the new installers, meter readers, field service representatives, supervisors, and various support personnel. We also forecast additional costs will be incurred for facility costs. Current SCE service center facilities cannot house the required incremental personnel. Facilities will either be modified to handle the incremental personnel or portable facilities will be leased. In 2006, we will incur $2.4 million for installation equipment and facility costs.

As meters are installed, the installers and meter technicians will utilize an RF verifier tool to test whether the communication module is functioning properly. We will also be procuring Local Area Network (LAN) assessment tools to help troubleshoot problems when we determine meters are not communicating with the network. The estimated costs associated with procuring this equipment in 2006 is $56,033.[16]

While Scenario 1 contained costs related to reconfiguring our meter testing equipment, in a partial deployment, we would be able to take advantage of our existing equipment without incurring any incremental reconfiguration costs.

(e) Installation Labor (MS-5)

(i) Residential and Small Commercial (< 20 kW)

In order to meet the partial deployment schedule, we estimate that additional personnel will be needed to install approximately 320,000 meters. We project the need for sixty-four project temporary installers during 2006.[17] The cost for the additional personnel to perform installations is estimated to be $4.6 million in 2006.

(ii) Complex Meters

To meet the partial deployment schedule, we estimate that additional personnel will be needed to install approximately 42,000 meters. While we rely on both full-time and contract resources in Scenario 1, we are solely utilizing full-time resources in the Zone 4 partial deployment. In 2006, we will dedicate thirty-five Meter Technicians to these installations. These

[16] In Scenario 1, this cost was charged to cost category C-10.

[17] As in Scenario 1, we base this estimate on the assumption that an installer will install twenty-five residential meters per day or eighteen commercial/industrial meters per day. Installation rates for the 75,640 meters covered by Rurals are different because of the vast difference in geographic locations between meters. They are twenty residential meters per day and five commercial/industrial meters per day.

resources will also need to work overtime. We have estimated that the overtime that will be worked is equivalent to twenty-five incremental full-time employees in 2006.[18] The cost for the additional personnel is estimated to be $5.3 million in 2006.

(f) Meter Installation Tracking Systems (MS-6)

We expect that meter failures will occur throughout 2006. We plan to hire an additional analyst to assist with tracking the meter failures. The analyst will look for trends in the failure data so that we can resolve communication or product issues with the vendor. We estimate the cost for this additional activity at approximately $99,000 in 2006.

(g) Panel Reconfiguration/Replacement (MS-7)

As described in Scenario 1, for the purposes of this preliminary business case analysis, we relied on our experience to develop a per meter damage cost estimate of $0.14. Overall, the costs associated with these activities are estimated to be $0.22 million in 2006.[19]

(h) Potential Customer Claims (MS-8)

We expect to incur costs related to potential customer claims as a result of the AMI deployment. However, for purposes of this preliminary analysis, these costs have been reflected as part of the cost estimate for cost category MS-7 since we were not able to delineate the customer claim related portion of the costs discussed above.

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[18] As in Scenario 1, we based these estimates on the assumption that a Meter Technician can install an AMI meter in 2.5 hours on average.

[19] Upon compiling the filing of our preliminary analysis, we discovered an error associated with the cost calculation for this cost code and the overall estimate will be revised accordingly in our formal application as necessary.

(i) Salvage/Disposal of Removed Meters (MS-9)

Throughout the meter deployment period, we anticipate that there will be meter failures in the field. Once the installer returns the meter to the service center, the meters that are still under warranty will be returned to the vendor for replacement. While we did estimate incremental labor costs for this activity in Scenario 1, we are assuming that we will be able to absorb this work with our existing staff in Scenario 14.

(j) Supply Chain Management (MS-10)

Our PAMM group is responsible for receiving and stocking meters at our central distribution facility. We expect to add more personnel to handle the increased volume of meters that will be received and processed in the central distribution facility. During the 2006 deployment period, we estimate the need for five material handlers responsible for receiving the meters from delivery trucks, storing the meters within the warehouse, and staging the meters for distribution. We also forecast the need for two warehouse clerks to maintain the integrity of the inventory by processing receipts, conducting inventories, and tracking assets. We will need one heavy transportation driver to deliver new AMI meters to our Meter Shop for testing and then out to the various SCE service centers for installation. Further, we anticipate the need for additional personnel to supervise the additional FTEs as well as project support personnel to provide forecasts to suppliers and to expedite and track purchases. Throughout the 2007 to 2020 time period, we will maintain some of these additional personnel to process the meter failures in the field. This processing includes sorting, packaging and shipping the meters back to the supplier as well as receiving and tracking the meters when they are returned. We will maintain two FTEs in 2007, tapering off to one FTE from 2009 to 2020. We estimate the cost for the additional personnel at $1.92 million over the 2006 to 2020 timeframe.

Currently our central distribution facility is at ninety-five percent capacity, maintaining a monthly average of 25,000 meters new business and system integrity. With a partial AMI deployment, we expect to increase our meter inventory by 20,000 meters monthly. Since the facility will need to accommodate both the new AMI meters as well as meters for the non Zone 4 customers, a new facility is required through first quarter of 2007 to house the meter inventory because our current facility cannot accommodate the volume of meters required for this deployment.[20] Other non-labor costs that we will incur from 2006 to 2020 are for miscellaneous equipment, packing supplies and freight costs for delivering materials to the service centers on a just-in-time basis. The estimated non-labor cost is $0.98 million over the 2006 to 2020 timeframe.

As the meters are delivered to the various service centers, additional personnel are required to process the meters at the service center locations. This processing includes verifying receipt of the meter, scanning them into the Field Tracking tool, and resolving variances in expected versus actual deliveries. We estimate the need for three additional employees to handle these activities at an estimated cost of $0.23 million in 2006.[21]

A critical assumption in our supply chain management analysis is that we will be utilizing RFID technology to facilitate the meter deployment processes. While this technology is being used in various industries, it is a new technology for us and we will plan to engage consultants with experience in this area to assist with the implementation. We estimate a cost of

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[20] The start-up costs for a new facility are detailed in cost category MS-11.

[21] In the cost calculations, these costs were inadvertently classified in cost category MS-9. This will be updated in the December filing.

$0.66 million in 2006 for these activities. Our estimate is based on cost information received from a potential vendor of these services.

(k) Training (Meter Installers, Handlers, and Shippers (MS-11)

For employee training needs, we looked at both the trainee-related cost of non-productive (seat) time spent in the classroom, as well as the cost of the trainer and training staff. Depending upon an employee's position, they will have to take training classes, ranging from new hire meter reading classes to meter installation classes. We estimate that the seat time costs for our field personnel will be $0.95 million over the 2006 to 2007 timeframe. The cost associated with developing materials for these training classes is estimated to cost $47,889 in 2006.

As mentioned in cost code MS-10, our current central distribution facility is at ninety-five percent capacity and a new facility will be needed to house the meter inventory. In addition to the actual facility leasing costs, we will incur equipment and supply costs to connect the new facility with our existing communications network. We estimate that we will incur $1.98 million in costs in 2006 to make this facility operational.

While we were able to avoid severance-related costs for our rural service center personnel in Scenario 1, we will not be able to avoid these costs in this partial deployment scenario. We will have eleven additional meter readers on staff after the deployment is completed. These employees will need to go through a severance process. The costs associated with this process have been captured in this cost category and are estimated to be approximately $0.5 million.[22]

(3) Operation and Maintenance [MS-12 through MS-14]

(a) Maintaining Existing Metering Systems (MS-12)

As meter failures occur throughout the deployment period and beyond, replacement meters will need to be set. FSRs will handle this work for the residential and small commercial customers. We estimate the need to hire additional FSRs beginning in 2006 to support the meter replacement activities.

Throughout the installation period, we expect our installers may discover potential energy theft situations that need further investigation. This assumption is based upon our experience with the Van-based AMR deployment. We plan to hire additional revenue protection investigators responsible for investigating these potential theft situations. With the increased potential to identify possible theft situations, we expect to increase our current investigator staff by two FTEs in 2006.

Currently, potential theft situations are usually brought to our attention by our meter reading staff. Given that a majority of the meter reading staff will no longer be needed in most of Zone 4, we will hire one additional support person to analyze meter read data in an attempt to determine potential theft situations to be further investigated.

The labor costs for incremental FSRs, revenue protection investigators and associated support personnel are estimated at $4.2

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[22] These costs were inadvertently classified as a 2010 cost. In reality, we would incur these costs in 2007 once the deployment is completed. This will be updated in our December filing.

million for the 2006 to 2021 timeframe. We will also incur $0.74 million in costs for tools, equipment, materials, supplies, uniforms and vehicle costs associated with these incremental personnel.

Additional non-labor costs are forecasted for battery replacements in the AMI meters installed on the greater than 200 kW commercial accounts. In 2016, we will begin the process of replacing these batteries and the replacement process will continue through 2021. We estimate the cost of the replacement batteries will be approximately $40,000.

As the AMI system is deployed, we anticipate new issues will develop from the implementation of new systems and the large number of meter changes. These will impact our ability to prepare and deliver accurate customer bills in a timely manner. We estimate the need for one FTE per year for project support to resolve AMI issues affecting billing. The estimated cost of this activity is $0.78 million over the 2006 to 2021 timeframe.

(b) Pick-up Reads (MS-13)

When a meter fails, the failure can be caused by a registration issue or a communication issue. In either case, it will be necessary to send a meter reader to collect a pick-up read from that meter in order to maintain timely and accurate customer billing. The labor costs for this cost category are estimated to be $0.67 million over the 2006 to 2021 timeframe.[23] Non-labor costs of $0.11 million will be incurred for tools, equipment, materials, supplies, uniforms and vehicle costs associated with these new meter readers.

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[23] As in Scenario 1, our personnel estimates are based upon a pick-up read rate of fifty-six reads per day.

(c) Meter Replacement Costs (MS-14)

As we described in cost category MS-12, we will need to replace the batteries in the AMI meters that are installed on the greater than 200 kW commercial accounts. While we did estimate incremental labor costs for this replacement activity in Scenario 1, we are assuming that we will be able to absorb this work with our existing Meter Technician workforce in Scenario 14.

In addition to the labor costs described in MS-12, we will also incur equipment costs of approximately $56,000 for tools, equipment, materials, supplies, uniforms and vehicle costs associated with the additional personnel handling meter replacements.

b) Communications Infrastructure

(1) Start-up and Design [C-1 through C-5]

(a) Review/Specify Security System (C-1)

As we design our new communications infrastructure, it will be necessary to assess the systems needed to ensure the security of the data transmitted within the network. We plan to engage contractor resources to assist us with this assessment. The costs for this assessment will be incurred in 2006 and are estimated to be $72,778.

To ensure the accurate transmission of data from the meter to the billing systems, we will dedicate personnel to review the operational design and system requirements. We estimate the need for additional personnel for these activities in 2006 at a cost of $0.1 million.

(b) Network Placement Site Surveys (C-2)

As in Scenario 1, there are no incremental costs associated with this cost category.

(c) Mapping Network Equipment on Company Facilities (C-3)

We will incur incremental labor costs during the 2006 to 2007 installation timeframe necessary to map MCC take-out point installations. Engineers will need to determine appropriate placement of the eighteen MCC take-out points within SCE's service territory. Once the MCC take-out point locations have been identified by the engineers, communication technicians will be responsible for installing the equipment. The labor costs associated with replacing failed MCC take-out points is also included in the estimate for this cost category. Overall, we estimate the labor costs for these activities at $0.12 million.

We plan to utilize contract personnel to handle the installation of the collectors, packet routers and the antennas for the MCC take-out points, the replacement of failed equipment, as well as the battery-change out process. The contractor labor and vehicle costs associated with these activities are $0.49 million.

(d) Staging Facilities for WAN/LAN Equipment and Mounting Hardware (C-4)

For the communications infrastructure, we will configure and test 100 percent of the network infrastructure equipment before it is deployed to the field for installation. The labor costs associated with performing these activities on 928 collectors, ten packet routers, and eighteen MCC take-out points is approximately estimated at $0.12 million for the 2006 to 2007 period.

In terms of maintenance costs, we currently do not have facility space that can accommodate the eight FTEs needed to maintain the communications network (these personnel costs are further described in cost category I-15). Our cost estimates includes the lease costs for a new facility which will continue over the 2006 to 2021 time period. In 2006, we will incur facility set-up charges such as costs to connect the new facility with our existing communications network. Overall, the costs associated with this facility are estimated at $0.33 million over the 2006 to 2021 timeframe.

(e) Review/Develop Strategies to Retrieve/ Process Data from Meters (C-5)

In determining the appropriate strategies to retrieve and process meter data, we needed to evaluate IT application solutions. Given the data retrieval and processing requirements associated with AMI, we needed to develop new applications or, in some cases, enhance existing applications to handle these requirements. Section II details the various IT application solutions that need to be developed or enhanced in the areas of meter supply chain management, meter change workflow, and meter read conversion. We have estimated approximately $0.2 million in contractor costs associated with the IT application solution design.

Our Billing and IT organizations will work jointly to determine the system requirements needed to prepare and deliver accurate bills in a timely manner based on data retrieval from AMI meters. We estimate $0.33 million in project management and business analyst support labor costs for these activities over the 2006 to 2008 timeframe.

(2) Installation [C-6 through C-11]

(a) Auxiliary Equipment (C-6)

Our analysis indicates that we will incur $0.42 million in auxiliary equipment costs over the 2006 to 2021 timeframe. With regard to the communications infrastructure, auxiliary equipment for the MCC take-out points and collectors is required in order to make the communications infrastructure operational. For the eighteen MCC take-out points, antennas and various equipment will need to be installed on each unit. Each of the 928 collectors will be equipped with a battery, which is estimated to have a six-year life. Beginning in 2012, we will need to begin changing the batteries in the collectors. In order to minimize installation error, we will provide the contractor personnel, who handle the equipment in the field, refurbished equipment instead of having them attempt to change the batteries in the field. In 2012, 100 new collectors will be purchased to begin this battery change-out process. The collectors that are removed from the network will be retrofitted with the new battery and then redeployed to the field.

For meter installations, there will be a subset of meters that require an external antenna to be installed in order to ensure that the meter can communicate properly with SCE's network.[24] The majority of the antenna costs will be incurred during the initial deployment period in 2006. However, the costs will continue through 2021 to reflect antenna costs associated with the replacement of failed meters and new meter sets related to customer

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[24] As discussed in Scenario 1, we assumed 1% of all residential and less than 20 kW commercial meter installations will require an external antenna. For greater than 20 kW commercial meter installations, we have assumed that 20% of the installed meters will require an external antenna.

growth. Overall, the cost is estimated to be $1.98 million over the 2006 to 2021 timeframe.

(b) Pole Replacement (C-7)

As in Scenario 1, there will not be any pole replacements required to support the partial deployment to Zone 4.

(c) Communications Link from Meters to Data Center, WAN/LAN Servers (C-8)

As in Scenario 1, there are no incremental costs associated with this cost category.

(d) Install Cross Arms/Mounting (C-9)

As in Scenario 1, there are no incremental costs associated with this cost category.

(e) Purchase Network Communication Equipment and Hardware (C-10)

Through mid-2007, we plan to install 928 collectors. Once the radio frequency networks are operational, we will be able to determine the specific areas within our service territory that are not communicating with the network and determine whether a collector can be deployed to cover that location or whether it will be a RF “blind spot,” and thus will not possess remote read capability.

The cost estimates for cost category C-10 also include the equipment costs associated with ten packet routers. As discussed previously, we will install packet routers in order to ease congestion on the network and ensure that data is transmitted to the network in a timely manner.

The equipment costs for the eighteen MCC take-out points are also included in the cost estimates for this cost category. In order to make the unit operational, each MCC take-out point will need to have four radios installed.[25]

Table 4-11 describes the annual deployment volumes associated with the communication infrastructure.

Table 4-11
Communications Infrastructure Deployment Volumes

Equipment	2006	2007	2008
Collectors	515	310	103
Packet Routers	7	3	0
MCCs	12	6	0

Throughout the course of the deployment, we expect to have various equipment failures. This will require us to incur additional labor and material costs to replace this failed equipment.[26]

The estimated costs associated with this cost category are $1.4 million over the 2006 to 2021 timeframe.

(f) WAN/LAN Training (C-11)

As in Scenario 1, there are no incremental costs associated with the training for the installation of WAN/LAN equipment.

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[25] Other equipment is also needed to make the MCC take-out point operational. The costs associated with this equipment are discussed in cost category C-6.

[26] As in Scenario 1, we have assumed an annual failure rate of 0.5%.

(3) Operation and Maintenance [C-12 through C-15]

(a) Cost of Attaching Communication Concentrators (C-12)

As in Scenario 1, there are no incremental costs associated with this cost category.

(b) Contracts to Retrieve Meter Data (C-13)

As in Scenario 1, there are no contracts required to retrieve the meter data and services.

(c) Dispatch and O&M of Field WAN/LAN and Infrastructure Equipment (C-14)

As in Scenario 1, there are no dispatch and O&M costs associated with infrastructure equipment.

(d) Electric Power for LAN/WAN Equipment and/or Meter Modules (C-15)

As in Scenario 1, there are no incremental costs associated with this cost category.

c) Information Technology Infrastructure

(1) Start-up and Design [I-1]

(a) Network Planning/Engineering (I-1)

As discussed above, we will be installing a communications infrastructure comprised of collectors, MCC take-out points, and packet routers. We will incur incremental labor costs of $0.24 million over the 2006 to 2008 period for the engineers and project support staff to design this infrastructure.

(2) Installation [I-2 through I-7]

(a) Computer System Set-up (I-2)

Our computing systems will need to be enhanced in order to support AMI. As previously discussed, we will develop new applications and enhance existing applications. To accommodate these applications, new hardware and operating systems, including fifty-eight servers and 1,640 Gb storage, will need to be procured to supplement SCE's existing computing infrastructure.

As described in Scenario 1, in support of meter inventory management, we are planning to utilize RFID technology. Since SCE has not used this technology previously, we will need to acquire the equipment to make this technology operational. The equipment we will procure includes dock door portals, barcode readers, hand-held readers and laptops. Additionally, we are planning to automate the asset tracking and work order aspects of the meter installation and removal processes and will require upgrading existing field laptops and providing additional laptops with GPS capability for the FSR installers.

Incremental SCE FTEs and contractor resources will be hired to handle the design and installation of the new hardware. The charges for the computing systems and associated labor are estimated to cost $6.4 million.

(b) Data Center Facilities (I-3)

No new data center facilities are required.

(c) Develop/Process Rates in CIS (I-4)

As discussed in Section II, we will be enhancing existing and developing new applications and enhancing existing applications to facilitate the meter supply chain management, meter change workflow, and meter read conversion processes. A critical element of this effort will involve verifying that the new applications or enhancements do not adversely affect existing systems that process meter changes and meter reads and calculate bills. To ensure there are no adverse impacts, we will employ comprehensive testing techniques, such as regression, integration, and unit and system testing. We will engage contractor resources to handle these activities during the 2006 to 2007 timeframe. We estimate the cost for these activities is $24,940.

(d) New Information Management Software Applications (I-5)

As discussed previously, we will make changes to our Meter Supply Chain system to automate our procurement processes. For the Meter Supply Chain application cost estimate, a critical assumption for this business case is that the Supply Chain project described in the 2006 GRC is deemed reasonable and receives cost recovery.[27] The major cost drivers for the changes needed to the Meter Supply Chain System include Supply Chain software enhancements and configuration for meter procurement process; software support for RFID additional software enhancements to support changes in the procurement process due to meter volume and deployment schedule; and integration with other systems in the meter deployment workflow. The Meter Supply Chain application described in the 2006 GRC will require substantial configuration to enable the

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[27] *See* SCE's 2006 GRC NOI.

embedded modules to support the business requirements for AMI meters. Additionally, these enabled modules will require integration with several systems, including vendor management, asset management, and financial management systems to create a highly automated system to support the end-to-end meter supply chain business process from meter vendor to field installation. We estimate the system configuration, related business process change management, and significant software upgrades will cost $13.5 million over the 2006 to 2021 timeframe.

(e) Records (I-6)

New applications will be developed and existing applications will be enhanced to support automating the meter change workflow and meter read conversion processes to accommodate the meter change volumes in this business case. The costs associated with developing the system requirements and database schema is captured in this cost category. We estimate the need for additional contractor resources at a cost of $0.53 million over the 2006 to 2007 timeframe.

(f) Update Work Management Interface to Process Additional Meter Changes (I-7)

Another critical element of system enhancement and development is designing the interfaces between the various systems and verifying that they are working as designed to ensure that information flows appropriately. We will engage contractor resources to handle these activities during 2006. We estimate the cost for these activities is $12,237.

(3) Operation and Maintenance [I-8 through I-16]

(a) Maintain Existing Hardware/Software that Translates Meter Reads into Bills (I-8)

Our Billing organization will partner with our IT organization in determining system requirements that will be needed to gather usage data and translate it into billing data. Once the system requirements are identified, they will also assist in the testing of new software functionality. We have estimated $1.2 million in project management and business analyst support labor costs associated with these activities over the 2006 to 2021 timeframe.

As detailed in the description for I-7, we will engage contractor resources to handle interface design and verification activities during 2006. In terms of the I-8 cost category, we estimate the cost for these activities is $20,452.

(b) Process Bill Determinant Data (I-9)

As usage data is collected and processed, we expect that additional customer service representatives will be needed to manually process accounts that the system is unable to process due to usage validation failures. Our personnel estimates of $3.8 million include the costs for 7.2 FTEs in 2006, reaching a steady state of 4.2 FTEs from 2007 to 2021.

In terms of our IT systems, we will also need to dedicate resources to defining the rules that will determine whether data is processed by the system or whether it needs to be reviewed manually by a customer service representative. We will engage contractor resources to handle these activities during 2006. We estimate the cost for these activities is $51,659.

(c) Contract Administration and Database Management (I-10)

As in Scenario 1, there are no incremental contract administration costs and the costs associated with infrastructure database management are included in I-16.

(d) Exception Processing (I-11)

As meter failures occur, we expect that accounts will fail billing system validations and will require manual intervention. This manual processing involves determining how a bill will be processed when a meter failure occurs during the middle of a billing period. Depending upon the nature of the meter failure, a judgment call is often required with regard to estimating consumption. Of the total meter failures, we are estimating that fifty percent will require manual processing. As such, additional customer service representatives will be needed to manually process these accounts to ensure that customers continue to receive timely and accurate bills. Our personnel cost estimates of $0.26 million over the 2006 to 2010 timeframe are based upon processing five accounts per hour for the first three years. As employees become familiar with how to handle these accounts, we expect their productivity to increase to ten accounts per hour, beginning in 2009.

In terms of our IT systems, we will need to dedicate personnel to defining and developing the process by which exceptions are handled. We will engage contractor resources to handle these activities during 2006. We estimate the cost for these activities is $62,499.

(e) License/O&M Software Fees (I-12)

Software licenses are required for the RFID technology solution incorporated in the meter supply chain management system. The cost includes an initial software license fee in 2006 and aggregate ongoing license fees for a total of $3.9 million during 2006 to 2021.

(f) Ongoing Data Storage/Handling (I-13)

As in Scenario 1, there are no incremental ongoing data storage/handling costs due to similar data capacity requirements in the "business as usual" case.

(g) Ongoing IT Systems (I-14)

As discussed in Section II, we will be developing new applications and enhancing existing applications to facilitate the meter supply chain management, meter change workflow, and meter read conversion processes. The ongoing O&M for these applications includes applications support, security administration, database administration support, maintenance and enhancement activities and is provided from a mix of contract and SCE labor. The total estimated cost for this activity is $8.4 million during the 2006 to 2021 timeframe.

(h) Operating Costs (I-15)

Once the communications infrastructure is fully operational, it will contain nearly 16,000 commercial meters with radios, 928 collectors, ten packet routers, and eighteen MCC take-out points. As the infrastructure is developed, we will need to phase in eight incremental full-time personnel to handle the on-going management of this network. Based upon our current experience with managing the network, our personnel estimate assumes that we will need twenty engineers and IT specialists for every 40,000 radios. The incremental labor costs from 2006 to 2021 are $7.2 million.

(i) Server Replacements (I-16)

We expect to replace the computing systems hardware identified in cost category I-2 on the basis of a five year technology refresh cycle. As such, the hardware refresh would occur in 2011 and 2016. As in Scenario 1, we did not include a final refresh in 2021 based on our assumption that the entire AMI system will be obsolete and need to be renewed with new technology and supporting infrastructure. Contractor resources and incremental SCE FTEs will need to be utilized to handle the design and installation of the new hardware. Incremental SCE labor costs for database management are also included in this cost category. The costs for refreshing the computing systems and associated labor are estimated to be $8.6 million.

d) Customer Service Systems

This section will describe the Customer Services related cost codes utilized in assigning costs for the Partial Deployment "operational-only" scenario (Scenario No. 14). For our purposes, Customer Services include Call Center costs, Meter Order Processing, Customer Communications and a portion of billing related costs.[28] We expect to spend $8.2 million in these cost categories over the entire analysis period through 2021. This section will not include meter reading and field services costs because these functions are essential to the Meter System Installation and Maintenance costs discussed in Section 1.(a) above.

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[28] The majority of billing system installation and operating costs are included in the Information Technology section (Section 1.(c) above) because cost codes I-9 and I-11 better described the billing related functions of "validating and creating billing determinate data" and "Exception Processing."

(1) Start-up and Design

Appendix A of the Ruling did not identify any "start-up and design" related costs in the Customer Service Systems categories. We have, however identified some billing related "start-up" costs. This includes the need for approximately four FTE's in 2006. These billing related start-up costs are associated with the specification of security systems, the development of data retrieval strategies, network planning, and the meter RFP proposal specifications. These costs are included under cost codes C-1, C-5, I-1, and M-2.

(2) Installation [CU-1 through CU-4]

This section will describe the one-time costs that are expected to be incurred during the installation process for AMI. Generally these costs are attributable to the implementation process itself, rather than on going operations. For the most part, these costs will no longer be incurred once the project installation phase is complete.

(a) Customer Records, Billing and Collections Work Associated with Roll-out of the Meter Change Process (CU-1)

The 2004 present dollar value of all costs in this category is expected to be $3.4 million over the duration of the analysis period. The majority of costs in this cost code relate to the processing of meter orders. Meter order processing costs are based entirely on the volume of anticipated meter change orders in excess of those that would normally be processed under normal business conditions. These costs are driven by routine change orders that fail to process initially in the automated meter processing system and must be manually reviewed as an exception and reprocessed. This is a labor-intensive process that is estimated to require approximately forty-four FTEs in the initial year of implementation (2006), and will drop off to three FTEs in 2007, two in 2008, one in 2009, and none thereafter, *i.e.*, no incremental cost once the installations are complete. Total meter order processing costs over the duration of the analysis period are expected to be $3.3 million.

Billing has identified the need for additional personnel to support their revenue protection activities. As discussed in cost category MS-12, we expect our installers to discover potential energy theft situations that need to be investigated during the deployment process. Our Billing organization will contribute to the resolution of these potential energy theft situations by performing analysis, interfacing with the field personnel, potentially rebilling customers' accounts, and corresponding with customers. We have estimated a cost of $38,505 for these activities over the 2006 to 2021 timeframe.

(b) Increased Call Center Activity During Installation Phase of the Partial Deployment "Operational-Only" Case (CU-2)

Call center impacts are expected to be minimal for the operational-only case, totaling $99,419 through 2021. We expect a relatively small volume of calls will result from media messages introducing the change to the affected customers. We expect a very low response rate of five percent (one half of one percent) of customers designated for AMI installation will call as a result of mass communications. This estimate is based on prior experience with similar mass communication campaigns. We expect a slightly larger volume of calls will occur as a result of the initial "meter change letter" that will be sent to all affected customers during implementation. We estimated that three percent of these customers would call if only a letter or bill insert is sent and four percent if door hangers are left after service is complete. The calls will result from the change letter, from the service personnel being observed on the property and from door hangers. The three percent and four percent estimates are based on management's experience with other communications in which a service visit is required. Call volume during the installation phase of this operational-only scenario is expected to reach 20,000 additional calls in 2006, dropping to zero by 2007. This would require the addition of 1.62 FTEs during the peak installation stage.

(c) Modification and Customer Support Costs for AMI Integration to the Outage Management Systems (CU-3)

SCE's Outage Management System (OMS) is expected to function as it does today, entirely independent of the new AMI infrastructure. We have not identified any incremental implementation costs related to OMS.

(d) Process Meter Changes for new Meter Installation and DA Accounts (CU-4)

The Meter Services Organization expects to incur costs of approximately $1.3 million (17.5 FTEs) during the installation phase in 2006 for engineering and sample testing of meters prior to installation. MSO's field metering installation work is classified as Meter System Installation costs in cost code MS-5. In addition, the Billing Organization expects to spend $715,349 (ten FTEs) in this cost code, all in 2006. This is for exception processing work directly related to meter changes during the installation phase. There are no costs in this category after the installations are completed.

(3) Operation and Maintenance [CU-5 through CU-10]

Cost code CU-8 has to do with "rate changes" and is not applicable within this scenario.[29] Cost codes (CU-6 and CU-7) relate to reduced customer safety and alternative safety measures, "because meter readers are no longer available." Although we recognize there is some foregone operational benefit in no longer having meter readers periodically inspecting our metering installations, we have no records relating to the frequency or value of occasionally finding unsafe, or faulty electrical service equipment. Thus, we have not included any estimate of this cost.

(a) Additional Rate Analysis (CU-5)

Even though there would be no new rates introduced under this operational-only scenario, we expect some increase in on going rate analysis work in the Billing Organization due to an increase in the number of customer inquiries arising from the large number of meter changes taking place. This results in 1.5 additional FTEs through 2021 for a total cost of $1.2 million.

(b) Customer Support for Internet Based Usage Data Communications (CU-9)

The Billing Organization expects increased costs of approximately $1.2 million through 2021 for the internet billing process. These costs relate to the design, development, testing and implementation of internet growth to accommodate customers that utilize internet-based usage data.

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[29] There was $141,000 assigned to this cost code in error. This will be corrected for the December filing.

(c) Outbound Communications (CU-10)

We would not expect to incur any incremental outbound communications costs under the operational-only case.

e) Management and Miscellaneous Other Costs (M-1 through M-15)

This cost category includes general overhead costs that span across two or more functional cost categories, such as project management and the administration of job skills training.

(1) Start-up and Design Costs (M-1 and M-2)

(a) Buyout of Existing Itron Contract for Automatic Meter Reading (M-1)

There would be no change in the Itron AMR contract because the majority of AMR meters are located outside of Zone 4, and SCE is committed through 2011 to the current contract, including the AMR meters in Zone 4, which would no longer be read after 2006. (*See* explanation for this cost code in Scenario 1, in Volume 3.)

(b) Meter RFP Process and Contract Finalization and Administration (M-2)

The development and review phases of the RFP process is expected to involve all the major departments participating in the project. As a major participant in this process, the Billing Organization has included a portion of a 0.15 FTE and about $16,591 in this cost code. All other participating organizations have included the costs associated with this process in the direct overhead costs associated with their respective start-up and installation cost estimates. The Procurement and Material Management Organization costs related to the preparation and review of the RFP were included in cost code MS-10, which was discussed previously in this section.

(2) Installation Costs (M-3 through M-11)

(a) Customers' Access to Usage Information (M-3)

The Billing Organization has included 1.5 FTES ($196,398) in this cost code for the first five years of the project. This is for expected costs related to increased support of customer requests for more detailed usage information.

(b) Employee Communication and Change Management (M-4)

The Billing Organization has included 0.23 FTEs for each of the first five years and a total of $33,227 in this cost code. This is for expected costs related to preparing and communicating AMI system information to employees and keeping them informed and up-to-date on the implementation of AMI and its related systems.

(c) Employee Training (M-5 and M-10)

The M-5 cost code includes "systems and rate structures training." Training of call center personnel, meter readers, and meter test technicians is included in cost code M-10. There are two elements to employee training costs; the trainee-related cost of non-productive (seat) time spent in the classroom, and the cost of the trainer and training staff, including training materials, classroom preparation, *etc*. All trainee-related costs are included in the operational costs of each individual operating organization. Most of the training will be provided by our JST. The Billing Organization and the Call Center supplement the JST training with their in-department training as needed.

For the partial deployment case, the estimated cost of all JST training in cost code M-5 is $345,829 for the duration of the analysis period through 2021. Billing organization training costs in this cost code are expected to be $33,227 for the same period.

(d) Meter Reader Reroute Administration (M-6)

The cost of recycling and rerouting the thirty percent non-communicating AMI meters has been accounted for in cost code MS-2, which was discussed previously in this Section. These costs are being absorbed as a portion of the cost of the three additional supervising FSRs assigned to each of the three major districts to supervise the AMI meter system installation process. The Meter Services Organization has included a total of $49,320 (0.5 FTE for 2006 only) in this cost code.

(e) Overall Project Management Costs (M-7)

Partial AMI deployment will require the formation of a project team similar to that anticipated for full deployment, but for a much shorter duration, since the installation phase of this scenario is only one year as opposed to five years for the full deployment case. The Project Management team will be made up of management representatives from each of the key operational areas. Each of the operating organizations has included the cost of their overall project management responsibilities in this cost category. In addition, we have assumed that an independent AMI Project Management Organization will be formed and made responsible for the overall coordination required to assure that all program goals and objectives are met in a timely and cost effective manner. As was the case for full deployment, the Project Management Organization would consist of three middle-management and two staff support personnel, however the duration of their existence would be significantly shorter for the partial case. The estimated total cost (in 2004 present value dollars) for the entire Project Management Organization will be approximately $8.3 million for the total analysis period through 2021.

(f) Recruiting of Incremental Workers (M-8)

Implementation of the partial deployment AMI program would affect the recruiting and hiring process within the three most heavily impacted organizations: Meter Reading, Call Center, and Billing. For the most part, the incremental cost of recruiting the anticipated increase in personnel has been included in the cost estimates for each organization separately in their respective cost codes. Because of the initial start-up impacts on FSMRO personnel, that organization has included $56,202 in this cost code.

(g) Supervision of Contracts and Technology Personnel Assigned to Hardware and Systems Development (M-9)

These costs are reflected within the individual operational areas and no additional costs are included under this cost code.

(h) Training for Other Traditional Classifications (M-10)

The overall training impact of this scenario was discussed previously in this Section under cost code M-5 relating to Systems and rate structure training costs. We estimate approximately $400,000 will be spent training Call Center, Field Services and Meter Reading personnel under cost code M-10.

(i) Work Management Tools (M-11)

Our business as usual operations include the cost of providing our management with the most up-to-date work management tools available. No incremental cost has been included for new or additional work management tools under any of the AMI scenarios.

(3) Operation and Maintenance [M-12 through M-14]

We have no anticipated O & M costs assigned to these cost codes.

2. Benefits

Table 4-12
Summary of Benefits for Scenario 14
(000s in 2004 Pre-Tax Present Value Dollars)

Benefit Categories	Total
Systems Operations Benefits	$23,031
Customer Service Benefits	1,536
Management and Other Benefits	6,213
TOTAL:	$30,781

a) System Operations Benefits [SB-1 through SB-13]

In this section we will address the potential "system operations" benefits expected to result from partial deployment of AMI to approximately 438,000 SCE customers. Appendix A of the Ruling identified thirteen such potential benefits that may occur. In our initial review of these potential benefits, we have been able to quantify $23 million in potential savings over the duration of the analysis period. These savings are expected to come from only three of the thirteen System Operations Benefit codes. We expect some net benefit from three others, which we are not able to quantify at this time. The remaining seven potential areas of benefit identified in the Ruling are either already being experienced by SCE, or have associated costs that more than offset the anticipated savings. The following sections will address all thirteen of the identified potential areas of system operations benefits.

(1) SB-1 Reduction in Meter Readers, Management and Support (SB-1)

This is the single largest area of benefits expected to accrue from partial implementation of AMI. We expect thirty-two meter reading positions will be eliminated, resulting in total cost savings of approximately $17 million over the analysis period. As was the case in the full deployment scenarios, we expect AMI will give us the ability to remotely read approximately seventy percent of all meters in Zone 4 (70% of 451,619 = 316,133). The remaining 135,500 meters that cannot be read automatically will continue to be read manually on a monthly basis by approximately forty meter readers.[30] We do not expect to eliminate any of the existing meter reader supervisor positions since each of the three major districts have only one supervisor who supervises both FSRs and meter readers. There will continue to be a need for these positions after AMI is deployed.

(2) SB-2 Field Service Savings (SB-2)

We currently complete approximately one-half of all "turn-off" and "turn-on" meter orders without having to actually turn the meter on or off. This situation occurs when a "turn-on" order can be matched to a "turn-off" order for the same location, on or about the same day. Such orders can be

[30] The remaining 30% of the meters with which we are unable to communicate are scattered throughout the Zone 4 area and are generally not adjacent to one another, thus making routine meter reading less efficient than it is today.

completed merely by taking a meter read, which currently requires a visit to the site at an average cost of approximately $17 per order for "next-day" service. Virtually all of these special meter reads for matched on/off meter orders could be eliminated and replaced with the daily AMI meter read. This benefit would result in the reduction of five FTEs and approximately $4.7 million in total costs over the duration of the analysis period.

(3) Reduction in Energy Theft, Identifying Broken Meters, Wrong Multipliers, and Metered Accounts not Being Billed (SB-3)

Upon review of this "potential benefit," we were unable to identify any incremental savings that may accrue due to AMI. All three of these situations can be identified as readily (if not more readily) by a meter reader making a monthly observation of the meter installation. In the case of energy theft and broken meters, we believe these would be even harder to identify through daily meter reads, since physical tampering is not readily apparent through meter readings, and a zero read does not necessarily indicate a broken meter. Many broken meters continue to register consumption, though it may not be correct. Rather than identifying this as a benefit, we have actually identified it as a potential risk, and have accounted for it accordingly.

(4) Phone Center Savings from Billing Inquiry Reductions Due to More Accurate Billing (SB-4)

Billing inquiries today are received for several reasons, only one of which is an inaccurate meter read. Based on a study using 2003 data, 22,791 calls were a result of meter reading errors. We used this number as a percentage of all calls to determine the percent of calls in subsequent years that would be projected as meter read error calls for each operational scenario. For the business case, we assumed that 100 percent of these calls would be avoided with automated meter reads.

For the partial deployment scenario, Table 4-13 shows the number of avoided calls that may result from the complete elimination of meter reading errors. Using the average number of Billing Inquiry calls answered per FTE in the Billing Inquiry specialty support group in 2003 (3,376), we are estimating a levelized reduction of 0.6 FTEs by 2007. This results in a total cost savings of $363,532 over the duration of the analysis period.

Table 4-13
Reduced Phone Calls – Partial Deployment

	2006	2007	2008	2009	2010	2011
Scenario 4	0	2,216	2,216	2,216	2,216	2,216

(5) Elimination of Rate Design Constraints Due to Meter Programming Limitations (SB-5)

Many currently installed TOU meters would require re-programming in the field if the Commission were to order a change in the definition of time-of-use on and off-peak periods, seasonal definitions, holidays, *etc*. This programming limitation does not exist with AMI meters since they meter fifteen minute and hourly consumption data.

This is a benefit that SCE is already obtaining as we are systematically changing all existing TOU meters to interval data recorders. However, we recognize this as a qualitative benefit, in so far as under the full deployment scenario, it could make more rate options readily available to all customers.

(6) Outage Management System (OMS) Benefits (SB-6)

SCE's transmission and distribution systems currently utilize a modern-day communications infrastructure that gives us all the OMS functionality that would be expected under full deployment of AMI. In fact, it is this vary communication infrastructure that is being built upon to gain access to the new AMI meters. Thus we expect no incremental OMS benefit from full AMI deployment.

(7) Better Meter Functionality/Equipment Modernization (SB-7)

The broader range of functionality of new electronic meters, such as those that would be used for AMI, provides many benefits over the electro-mechanical predecessors. The most apparent advantage is the universal "one-size-fits-all" capabilities of the modern meter. Though there are still a number of variations in "meter forms," and instrument transformers are still the norm for large accounts, the number of variations is not nearly as broad as it once was. For the larger C&I accounts, SCE is already taking full advantage of this functionality benefit in its "business-as-usual" case. This more universal metering functionality is recognized as a significant qualitative benefit relating to AMI deployment among the smaller C&I and residential accounts.

In addition, the incorporation of two-way communications provides the potential for meter diagnostics and voltage verification that we do not have today. AMI meters and/or complimentary devices are anticipated to have the potential to alert the customers of system peaks and could automatically trigger some form of direct load control. They could also provide a means to allow the customer to directly access their own metered usage data for informational purposes. One such device to automatically control customer thermostats will be including in conjunction with our Demand Response plus Reliability scenarios to be discussed later in this Volume.

(8) Remote Service Connect/Disconnect (SB-8)

SCE responds to over one million turn-on/turn-off service requests annually, and disconnects and reconnects nearly one million additional meters for credit related, non-payment issues. Nearly one-half of the on/off service requests and all of the credit disconnects require the physical disconnection of service at the customer's meter. AMI meters could be equipped with a remote disconnect switch contained within the meter, which could provide the ability to "remotely" turn electric service on or off.

This is a costly option to be added to an AMI meter. A typical 200 amp disconnect switch (not including additional hardware / software necessary to activate) would cost approximately $150 to $200 per meter. The cost of responding to an on/off service order is approximately $17 for next-day service and $24 for same-day service. Thus, the installation of a remote disconnect switch would only make sense where there is frequent customer turn-over and/or where credit collection problems exist (*i.e.*, student housing, apartment complexes, *etc.*). Even with turn-over rates of two or three times per year at any specific location, the cost effectiveness of this option is marginal at best. For this reason, we have not included remote service connect/disconnect as a savings in any of the AMI deployment scenarios.

(9) Improved Meter Accuracy and More Timely Load Information (SB-9)

The new solid state meters are individually slightly more accurate over the full range of their rated load capability than their electro-mechanical predecessors. However, since today's meters generally function for many years within the Rule 17 accuracy limits of ± one percent, this benefit must be viewed as qualitative. On the other hand, the potential for increased initial failure rates (as was the case with RTEM meters) has been identified as a potential risk.

Since customer load information would be available in a timelier manner (*i.e.,* hourly, daily, weekly, *etc*.), under the full deployment scenarios where interval data is accessed on a massive scale, we believe it will provide some benefit to SCE with regard to forecasting accuracy and in reducing resource acquisition costs. These costs savings have been identified in Scenarios 3 through 11 in which our Energy Supply and Marketing Organization (ES&M) has included interval data collection and processing costs and forecasting benefits as part of the on going operations. However, no such cost savings have been identified in any of the partial deployment scenarios.

(10) Distribution Planning and Design (SB-10)

In theory, AMI would give us the opportunity to aggregate coincident customer loads within any specific area in order to determine the demand on a distribution circuit or an individual distribution transformer. This would be a significant planning tool except that SCE already has a Transformer Load Management (TLM) program in place that accomplishes the same thing.

(11) Reduction in Unaccounted for Energy (UFE) (SB-11)

As described previously in this Section, AMI gives us the opportunity to aggregate customer loads within any specific area in order to determine the demand at any particular time. In those areas where we are able to isolate substation metered loads, AMI could potentially provide a means of isolating geographic areas and comparing actual metered customer load to substation metering, either over time or during peak periods. This kind of comparison could, theoretically, identify areas where an inordinate amount of UFE may exist. As a practical matter, substation metering cannot be readily isolated to a specific geographic area, or to a particular set of customer meters with a great deal of confidence, because portions of individual circuits are often switched from one distribution circuit to another for maintenance or in response to circuit interruptions, etc.

Using primary circuit metering and system loss modeling, we currently have the analytical ability to compare total customer consumption and calculated transmission and distribution losses to system generated and purchased loads, and thus determine the amount of UFE. From this type of modeling, we believe the UFE to be relatively insignificant.

An offsetting cost factor with regard to UFE is that the "watts lost" rating of electronic meters is typically one-and-one-half to two watts per meter greater than that for the electro-mechanical meters they would be replacing. For the partial deployment scenario this would amount to approximately one megawatt of load, 24 hours per day, 365 days per year (or 8760 MWh). At $85/kW year and $70/MWh[31] this equates to about $85,000 worth of peaking capacity cost and $600,000 worth of energy per year.

(12) Self-Generation Monitoring (SB-12)

SCE currently has the capability of monitoring net energy delivered to (or received from) its self generating customers. Currently, metered data is billed on a monthly basis and none of SCE's tariffs require "real-time" monitoring. It is conceivable, however, that some demand response benefit could result from the ability to provide the customer with real-time, interval consumption

[31] These values are suggested for use in Appendix A of the Ruling.

data, even under the current tariffs. No studies have been conducted, however, to determine to what extent customers would respond to real-time consumption data, nor have we determined what the cost would be to provide the customer with real-time data. Thus, for purposes of the "operational only" scenario, we have not identified any net benefit to result from real-time net energy metering.

(13) Reduction in the Amount of Time Required to Implement New Rates or Load Management Programs (SB-13)

The SB-5 benefits addressed above recognized the ability to redefine TOU time periods, or seasons, without the need to physically reprogram meters in the field. The time required to make such a change with the majority of today's meters is actually prohibitive. However, for the vast majority of customers on the general service rates, there has not been a compelling reason to redefine time periods or seasons in recent years. As will be discussed later in the demand response scenarios, the ability to implement new rates in a timely manner, especially rates with narrower on-peak periods (or variable peak periods such as CPP), would be a significant benefit.

b) Customer Service Benefits [CB-1 through CB-13]

The Ruling identified thirteen "additional" customer service benefits, most of which relate to billing and demand-side management. Our review of these potential areas of benefit resulted in anticipated annual savings of approximately $1.5 million over the sixteen-year analysis period of the partial deployment "operational-only" scenario. This savings is all attributable to improved billing accuracy (CB-1) due to the elimination of estimated bills and timelier billing due to elimination of meter accessibility problems. Additional customer service benefits are being recognized in the demand response scenarios (Scenarios 16 through 23).

c) Management and Other Benefits [MB-1 through MB-10]

We expect to reduce costs by approximately $2.9 million through 2021 by decommissioning thirty hand-held meter reading devices. Typically these devices would be replaced every five years. This is a cost that would no longer be incurred and is classified as a benefit in the MB-1 category. An additional $3.3 million in savings is expected to result from a reduction in meter inventories (MB-4) due to the expanded uniformity of meters.

Most of the remaining previously identified potential benefits in this category are a function of the ability to replace existing electro-magnetic meters with electronic meters. These are benefits that are already attainable in the business as usual case and not incremental savings attributable to AMI deployment on a large scale.

3. Uncertainty and Risk Analysis

As discussed in Volume 2 and in accordance with Attachment A of the Ruling, we performed a risk assessment of the operational costs and benefits for the partial Zone 4 deployment scenarios that could result from uncertainty or lack of data. The risk analysis we performed for this scenario is based on the specific cost and benefit data discussed in the sections above.

For analytical purposes, this operational risk assessment focuses on those cost and benefit codes that have estimates (in cumulative nominal dollars (*i.e.* 2006-2021) of $500,000 or greater. Once the appropriate cost and benefit codes were identified, we developed the most likely high and most likely low ranges for each of the cost and benefit cost categories. Consistent with the Ruling, we then applied a Monte Carlo statistical approach to create a probabilistic range around our estimate.

For Scenario 14, the total present value cost estimate for full AMI deployment is $161.8 million. Five cost codes in Scenario 14 represent over 60 per cent of the total cost for this scenario. The most significant cost code (MS-3) in Scenario 14 is estimated at almost $52 million and involves meter and meter-related communications equipment obtained from a single vendor. We estimated a range for this cost code at: plus twenty percent and minus five percent. This range is based on our historical experience with price differences that occur between an RFI and the ultimate final contract. We find that vendor price increases of as much twenty percent are due to better understanding of scope, warranty requirements, and contract terms and conditions. We based our estimate on vendor quotes we received in the RFI. The range also reflects the uncertainty of meter failure. Our information technology computing systems lifecycle costs have a range of plus or minus forty percent due to the uncertainty of the data processing and storage required. Our software development costs ranged plus forty percent to minus fifty percent based on the uncertainty of the final design. The meter and field communication installation costs may vary by as much as plus fifteen percent to minus twenty percent based on installation productivity. Under this partial deployment scenario our Billing organization estimate may vary in a range of plus twenty percent to minus fifteen percent depending on the number of exceptions processed.

The primary operational benefits relate to the reduction in meter readers and associated meter reading costs that results in aggregate savings of nearly $31 million. We do not expect any variation because the forecast reduction is solely a function of the AMI system communication coverage for Zone 4. The other identified operational savings were less than the $500,000 threshold we used for analytical purposes. As a result, we did not include any operational savings below this threshold in the statistical analysis.

Using the cost ranges estimated above, the application of the Monte Carlo statistical analysis of costs resulted in a range of $152.3 million to $178.9 million around the estimated cost of $161.8 million for this scenario. The statistical analysis indicates that our cost estimate has about a twenty-five percent confidence. This means that the project has a seventy-five percent chance of overrunning. Our preliminary cost estimates do not include contingency. However, based on our analysis we should consider a contingency of approximately $9 million in our final application to reduce the risk of overrun. This contingency amount is the difference between our cost estimate and the value at the ninety percent confidence level.

4. Net Present Value Analysis

Table 4-14 summarizes the overall pre-tax costs and benefits of Scenario 14. Also shown is the after-tax NPV for these scenarios on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period

Table 4-14
Summary of Cost/Benefit Analysis for Scenario 14
($ Millions)

Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. NPV
$161.9	$30.8	($131.1)	($85.0)	($441.7)

Scenario 14 results in a negative Revenue Requirement Present Value of $441.7 million and does not support the implementation of partial AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the scenario 1 analysis, plus the recovery of SCE's net investment in any removed meters, plus the rate of return and tax impacts of the AMI-related investments.

B. Scenario 15: Operational Only - Outsourced

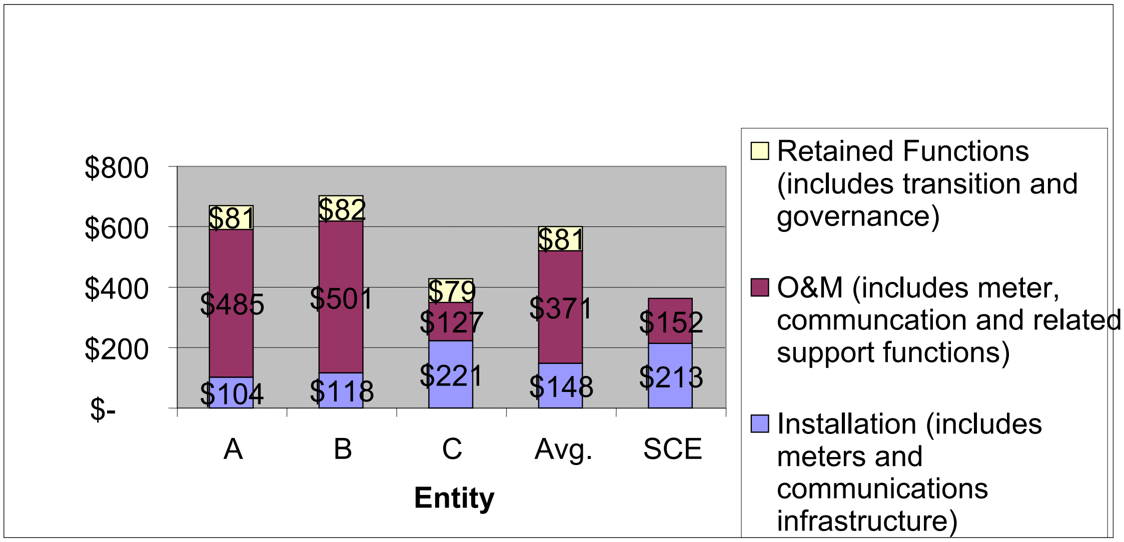
The “full-deployment” outsourcing analysis was presented in Volume 3 as Scenario No. 2. In that section we provided an overview of SCE's general policy considerations regarding outsourcing and we described our approach to analyzing the available outsourcing options for both full and partial deployment of AMI. In this section, we will present the results of the outsourcing option as it relates to the partial deployment scenarios. We will not repeat the general discussion relating to matters that were common to the analysis of both full and partial deployment. All stated values in this scenario are in nominal 2004 dollars and no attempt has been made, at this time, to convert them to present-value dollars as were used in the other scenarios. Therefore, caution must be used in making direct comparisons to any of the other partial deployment scenarios presented in this volume.

1. Overview of Approach

a) Conclusions

Our analysis concludes that there is no potential economic value to outsourcing significant portions of the partial deployment case. Figure 4-2 below summarizes the results of the three most viable outsource provider’s cost estimates compared to SCE’s cost estimates for the same partial-deployment scenario.

Figure 4-2
Scenario 15 Summary Financial Analysis – Outsourcing Partial Deployment
(Cost in Millions of Nominal 2004 Dollars)



b) <u>Economic Assessment</u>

As was the case with full deployment of AMI, our preliminary economic assessment does not indicate that the savings opportunity normally associated with traditional outsourcing undertakings (such as IT, Finance, or HR) exist for outsourcing the partial AMI case. The total cost to SCE in both the full deployment and partial deployment outsourcing scenarios would be higher than the equivalent of SCE retaining the work in house. For the partial deployment the total cost of outsourcing (based on an averaging of service provider feedback) is estimated at $584 million whereas the cost of SCE performing the work is estimated at $365 million. To ensure an effective comparison both the outsourced scenario and the internal scenario were developed with all components included (*i.e.,* representing the end-to-end AMI solution including "back office" functions") and with a consistent inflation (escalation) factor applied to all scenarios.

In the partial case, outsourcing major components of the installation and operational phases of AMI would result in duplication of key customer service processes such as meter order processing for meter changes, billing exception processes resulting from new meter installations and meter failures, *etc.* SCE already has many of these processes and resources in place and would have to keep those resources in place not withstanding some level of outsourcing. Such duplication would not exist if SCE were to undertake a partial deployment of AMI on its own.

c) Summary of "Outsourcing" Findings

Although the scope and size of the partial-scope deployment scenario are much more manageable and represent a scope that has been outsourced by other organizations, there does not appear to be a compelling value proposition for outsourcing a partial deployment scenario unless it is intended as a pilot or proof of concept project. The initial analysis indicates that there is no compelling financial justification to outsource a partial deployment. However, the justification may exist for other business objectives.

There were four integrated solution providers that participated in our analysis. Each provided varying degrees of completeness and each had somewhat different views of how the partial scope deployment AMI outsourced services would be provided. However, in the analysis, each has been normalized to allow a similar "apples-to-apples" comparison.

Based on the financial comparisons, the scope of services does not provide the traditional outsourcing value of reduced expense. This scope of services does not present the opportunity to consolidate the labor force, to leverage existing services, to buy products at significantly reduced rates or improve operational efficiency, all of which are typical ways an outsourcer can achieve lower costs. Moreover, outsourcing a partial-deployment scenario may introduce redundant services and systems into the solution.

(1) Installation and Start-up

The opportunity for outsourcing this scope of work is financially imbalanced because there will be a large infrastructure and labor overlap between the outsourcing provider and SCE. The financing of the meter assets and associated hardware components appears to have lower cost through SCE financing. All outsourcing providers proposed that SCE should finance the meters, given that SCE's cost of capital appears lower than the service providers' rates.

As with the full deployment scenario, all of the integrated service providers proposed to partner with a meter manufacturer as part of their solution and they intended to complete the installations with contract labor. This use of contract labor may have union implications and would require further investigation.

Meter testing assumptions varied by provider. The testing rate would need to be adjusted to meet the required service. This has potential pricing impact, but cannot be estimated until the exact meter manufacturer is chosen and a commitment to a specific defect level is achieved.

The partial deployment scenario requires an inventory and distribution system that can handle the approximately 460,000 meters. All other IT modifications required for AMI would still be necessary. SCE would complete those modifications. SCE would also be required to perform the majority of the estimated customer application upgrades regardless of the decision on outsourcing. The exact cost of such interfaces has not been estimated, but there will be some cost to move data from the provider to SCE and visa versa that has not yet been accounted for.

The initial assessment of the partial outsourcing scenario indicates that from a cost perspective, the start-up installation of a partial deployment would be less expensive for SCE to retain in-house than to outsource these functions. The outsourcing scenario also adds a governance cost into the total cost.

(2) <u>Operations & Maintenance</u>

On-going operations and maintenance for the partial-scope deployment was assumed to include O&M of the existing meters during the deployment phase (with inherent ramp down with the AMI rollout) and O&M of the new meters during the deployment phase (with inherent ramp up with the AMI rollout) and beyond (deployment was estimated to be in the first year). The responses from the service providers included all functions up to and including delivering valid meter data to the billing function (with validation limited to reasonableness type of validation).

Determination on treatment of staff and the transition of staff to a service provider were dealt with only at a high level for this analysis. A number of issues related to union participation, severance, attrition, and training would also have an impact on the ongoing O&M function and cost.

The three integrated solution providers all provided solution descriptions that, at a high level, appear to meet the requirements. Additional analysis would be required to ensure work flows, hand offs and responsibilities, and systems needs were fully defined.

Given that the cost of outsourcing exceeds the cost of SCE to perform these functions, we do not believe that outsourcing a partial AMI deployment offers any superior benefits.

(3) Retained Responsibilities and Governance

Governance and relationship management costs were estimated at 1% of the service provider estimated fee. These costs would be necessary to ensure that the performed functions and products meet the requirements and continue to comply with all regulations.

Retained responsibilities were identified for the meter functions (currently within our MSO, FSMRO, and TDBU (Rurals) organizations). These functions primarily would represent service delivery oversight, planning, design, customer relations, and other strategic functions.

Finally, the responsibilities related to implementation and operation of AMI that were considered to be out of scope in the outsourcing were identified as a utility-retained function and cost.

C. Scenario 16: Operational Plus Demand Response - TOU Default With Opt-Out

Scenario 16 adds a Demand Response element to the partial deployment operational-only scenario (Scenario 14). Not only do we include the costs associated with partial operational deployment of AMI as presented in Scenario 14, but we have added the cost associated with placing and keeping a minimum of eighty percent of the eligible AMI metered customers on time-of-use rates, ten percent that "opt-out" to their current rate and ten percent to a CPP-F rate, as in Scenario 4.[32]

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[32] Our assumption is that 80% of the 70% (or approximately 56%) of the meters that are actually communicating would be able to participate on the default rate

As was the case with Scenario 14, all costs and benefits included in the analysis of this scenario were estimated relative to the "business as usual" case. Table 4-15 summarizes the 2004 present-value dollar costs and benefits associated with Scenario No. 16, and compares these costs to Scenario 14.

Table 4-15
Scenario 16 Cost and Benefits Compared to Scenario 14
(Millions in 2004 Present Value $)

	Scenario 14	Scenario 16	Difference
Costs	$161.9	$262.5	$ 100.6
Benefits	$ 30.8	$63.0	$32.2
Pre-Tax Present Value	($131.1)	($199.5)	($68.4)
After Tax NPV	($85.0)	($126.8)	($41.8)
Rev. Req. NPV	($441.7)	($256.1)	$185.6

Scenario 16 derives all of the operational benefits previously discussed in Scenario 14 above plus approximately $28.1 million in demand response benefits resulting from energy and demand reduction savings attributable to time-of-use rates, and $4.1 million in additional benefits from making energy consumption information available to customers on the Web.[33] These added benefits are offset, however, by added costs of more than $100 million, most of which is due to the massive customer communications campaign that would be required in order to meet the stringent twenty percent maximum opt-out limit imposed by this scenario.

1. Costs

The total estimated costs of Scenario 16 are detailed in Table 4-16

[33] The "Web" benefits derived in this scenario are the same as in the full deployment case because these are benefits derived from the upgraded web-based system that will be required to accommodate either the full or partial deployment case.

Table 4-16 Summary of Costs for Scenario 16 (000s in 2004 Pre-Tax Present Value Dollars)	
Cost Categories	**Total**
Metering System Infrastructure	$85,134
Communications Infrastructure	7,819
Information Technology Infrastructure	87,752
Customer Service Systems	52,104
Management and Miscellaneous Other	29,703
FSMRO (Severance SB-1)	1,062
TOTAL:	$262,512

a) Meter System Installation and Maintenance

(1) Start-up and Design

Appendix A to the Ruling does not identify any cost categories for meter system start-up or design. As such, any start-up or design activities have been classified as an installation cost below.

(2) Installation and Maintenance [MS-1 through MS-11]

For this scenario, the descriptions of activities and the associated costs for these cost categories are identical to those described in Scenario 14.

(3) Operation and Maintenance [MS-12 through MS-14]

When comparing the cost estimates for Scenarios 14 and 16, the cost difference can be attributed to changes in the labor costs associated with our Billing organization, which are being charged to cost category MS-12. As with Scenario 14, we anticipate new issues will develop as a result of the implementation of new systems and the large number of meter changes. However, we anticipate that these issues will be more extensive given the introduction of new tariff schedules to facilitate customers' demand response. We have estimated that additional personnel will be required in the initial phases of the implementation. As such, the labor costs for this area are estimated to increase by $0.55 million to $1.3 million over the 2006 to 2021 timeframe. The labor and non-labor costs of $5 million that are charged to MS-12 to support meter replacement and revenue protection activities are estimated to remain the same in this scenario as in Scenario 14. The descriptions of activities and the associated costs for cost categories MS-13 and MS-14 are the same as those described in Scenario 14.

b) Communications Infrastructure

(1) Start-up and Design [C-1 through C-5]

In Scenario 16, the descriptions of activities and the associated costs for cost codes C-1, C-2, C-3 and C-4 are the same as those described in Scenario 14.[34] However, there are changes in the costs related to cost code C-5. As discussed in Scenario 14, cost code C-5 captures the costs related to determining the appropriate IT application solutions to retrieve and process meter data. As discussed in further detail below, we will need to enhance additional applications in order to facilitate demand response capabilities in our systems. Given the additional applications that we are enhancing, we expect that the contractor costs associated with IT application solution design will increase from $0.20 million to $0.37 million.

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[34] Upon compiling the filing of our preliminary analysis, we discovered an error associated with cost code C-1. It incorrectly indicates additional costs are charged to this cost code in Scenario 16. The overall estimate will be revised accordingly in our formal application as necessary.

Our Billing organization will continue to partner with our IT organization in determining strategies for data retrieval and processing. They will assist IT in determining the system requirements needed to prepare and deliver accurate bills in a timely manner to those customers with AMI meters. Given the additional applications that we are enhancing, we expect that the project management and business analyst support labor costs associated with these activities will also increase. In addition, our Billing organization will need to dedicate personnel to determine how its processes will be modified in order to accommodate the additional work that will be generated due to accounts failing system validations for usage-related reasons. We have estimated an increase from $0.33 million in Scenario 14 to $1.2 million in Scenario 16.

(2) <u>Installation [C-6 through C-11]</u>

In the installation area, there are two main differences between the Scenario 14 and Scenario 16 cost calculations. First, in Scenario 14, we did not have any incremental costs associated with cost code C-8. In Scenario 16, we will incur charges related to this cost category for Digital Signal Level 3 (DS3) costs. A DS3 is a high-capacity telecommunication circuit. We plan to install one DS3 to accommodate the additional traffic that is expected on our website. The bulk of the non-labor costs are associated with the leasing costs that we will incur from the telecommunication provider. We will also incur contractor costs in 2006, 2011, 2016 and 2021 associated with the installation and replacement of the equipment discussed in cost category C-10. Overall, the cost is estimated to be $0.96 million over the 2006 to 2021 timeframe.

Second, we also have differences in the costs associated with cost category C-10. In this scenario, we will continue to incur the $1.4 million in costs for the communications infrastructure hardware and equipment that were discussed in Scenario 14. In addition, we will need to procure communication equipment that will link SCE's network to the DS3 discussed above. This equipment will be installed in 2006 and will need to be refreshed every five years. The cost associated with this equipment is $81,358 over the 2006 to 2021 timeframe.

(3) Operation and Maintenance [C-12 through C-15]

In Scenario 16, the descriptions of activities and the associated costs for cost categories C-11, C-13, C-14 and C-15 are the same as those described in Scenario 14. The changes are related to cost category C-12. In Scenario 14, we did not have any charges associated with this cost category. However, in Scenario 16, cost category C-12 is used to capture the costs associated with various development tools licenses and fees. Non-labor costs of $49,746 are being charged to this cost category over the 2006 to 2007 timeframe.

c) Information Technology Infrastructure

The information technology and application cost category captures the costs associated with applications and computer services. In addition to the costs incurred for the full deployment operational case, we will incur additional charges when demand response rates are introduced.

(1) Applications

In the Scenario 14 discussion, we described the various applications that would need to be developed and/or enhanced. For Scenario 16, these same applications would be required. In addition, enhancements would be required to our Service Billing, Usage Calculation, Wholesale Settlement and SCE.com systems. The discussion that follows provides a brief description of enhancements to these systems.

(a) Service Billing

Enhancements will need to be made to our Service Billing system, which provides the core functionality to calculate customer bills. The terms of each of the rate schedules are translated into "service plans" and stored within the Service Billing system. A service plan defines the types and levels of charges and specifies how a billing statement will be calculated for a service account. In Scenario 16, new tariff schedules will be introduced. As a result, changes will need to be made to the Service Billing system to include the resulting service plans so that billing statements can be calculated.

(b) Usage Calculation

A core system functionality that will be needed to support AMI involves the processing of interval data. Currently, we have a fairly small-scale system, called the Customer Data Acquisition system that handles calculating usage for existing customers with interval meter data. In this scenario, we will need to develop a new Usage Calculation system in order to handle the large volume of interval data that will be associated with the full deployment of AMI. As demand, energy, and power factor data are collected from meters, it will be transferred to the Usage Calculation system. The data will then be aggregated into values corresponding to the applicable season and time periods dictated by the terms of the service plan. Once aggregated, this data is transmitted to the Service Billing system for bill calculation and to the Wholesale Settlement system for financial settlement.

(c) Wholesale Settlement

Significant enhancements will need to be made to the Wholesale Settlement system. This system handles calculating various settlement charges related to power procurement activities with the California ISO and other counterparties. In the current system, the hourly usage values that are used to determine these settlement charges are calculated using load profiles, which are applied to monthly reads. Once demand response tariff schedules are introduced, the usage data received for wholesale settlement will be actual interval usage data, replacing the use of load profiles. As such, the Wholesale Settlement system will need to be enhanced to handle the aggregation of the increased volume of actual interval usage data associated with the nearly 0.44 million AMI meters. The data needs to be aggregated by customer class and associated with the appropriate generation schedule and generation resource usage data in order to calculate settlement charges.

(d) SCE.com

Significant enhancements will need to be made to SCE.com in order to facilities customers' participation in demand response programs as well as accommodate the expected increase in customer access. Currently, SCE.com provides customers with their monthly energy usage data and corresponding monthly costs. In terms of additional functionality for the user that will be developed, residential customers will have the ability to view their hourly energy usage data from the previous day while commercial and industrial customers will be able to view fifteen minute data from the previous day. Customers will have access to available interval data for up to 13 months and will be able to view charts and graphs for comparing applicable data. Customers will also be able to access analytical tools to manage energy usage and control costs. Customers will be able to view and monitor CPP rates and event details.

A key assumption driving the cost of these enhancements is related to the increased traffic expected on SCE.com. During non-critical event peak hours, we expect an increase in access over what we are experiencing today. During critical event peak hours, we expect a significant increase. The increase is based upon the assumption that we will have a significant volume of users accessing SCE.com during any given critical peak hour and that we will need to support an increase in concurrent user access as well.

(2) Start-up and Design [I-1]

For this scenario, the description of activities and the associated costs for this cost category are the same as described in Scenario 14.

(3) Installation [I-2 through I-7]

(a) Computer System Set-up (I-2)

Our computing systems capacity will need to be increased in order to support AMI. As previously discussed, we will enhance existing and develop new applications. In Scenario 16, we are developing and enhancing additional applications to process the extensive volume of interval data that will be collected from meters to facilitate time-of-use billing. We are also enhancing SCE.com, our primary customer interface system. As compared to Scenario 14, in Scenario 16, we will need to procure additional hardware, storage, and operating software, including four additional processors and an additional 155 Gb of storage, to supplement the computing infrastructure designed for Scenario 14. Given the data processing requirements of the demand response scenario, we will also need to increase the mainframe resources by 123 MIPS and 254 GB in additional storage.

Another major cost driver in this cost code is related to customer bill printing. As new tariff schedules are introduced to facilitate customers' demand response, we are expecting that the number of pages in a typical customer's monthly bill will increase from four to six. In order to control postage cost increases, we will need to maintain the current number of pages by printing on both the front and back of the bill stock. Our current printers do not accommodate printing bills in this manner. As such, new duplex printers will be required to process these new six-page bills.

In Scenario 16, to facilitate demand response, we will be posting a customer's usage data on SCE.com, as discussed in further detail below. Upgrades will need to be made to our website servers in order to accommodate additional customers accessing SCE.com.

In Scenario 14, the cost associated with our computing systems upgrades was estimated to be $6.4 million. In Scenario 16, the costs are more extensive, estimated at $13.2 million.

(b) Data Center Facilities (I-3)

In Scenario 14, we did not have any incremental costs associated with cost category I-3. As discussed in cost category I-2, we will be procuring duplex printers. Due to the size of the duplex printers, we will need to incur additional charges related to facility modifications. Non-labor costs of $92,515 are being charged to this cost code in 2006.

(c) Develop/Process Rates in CIS (I-4)

As discussed in Scenario 14, a critical element of our IT application development efforts involves verifying that the new applications or enhancements do not adversely affect existing systems that process meter changes and meter reads and calculate bills. To ensure there are no adverse impacts, we will employ comprehensive testing techniques, such as regression, integration, unit and system testing. Since we are introducing more extensive application changes in Scenario 16, we will need to dedicate additional contractor resources to handle the testing activities. As such, we estimate the cost for these activities to increase from $24,940 to $221,710.

(d) New Information Management Software Applications (I-5)

As described above, we will need to significantly enhance our Wholesale Settlement system. The costs associated with developing the system requirements and database schema for this system are captured in this cost category. In addition, with the introduction of additional applications in Scenario 16, we will need to engage additional contractor resources to handle interface design and verification activities during the 2006 to 2021 timeframe. These activities are charged to various cost codes, including I-7 and I-8, depending upon the interface. The overall cost estimates for this cost code will increase from $13.5 million to $14.2 million.

Our Customer Service organization will partner with our IT organization in developing system and business requirements for the revisions that need to happen to SCE.com. They will also participate in testing the new website before it is launched for customer use. After the website is launched, they will identify system improvements to ensure that customers find the website easy to use. We have estimated $0.17 million in labor costs associated with these activities over the 2006 to 2007 timeframe.

(e) Records (I-6)

Additional applications will be developed and enhanced in Scenario 16, including Usage Calculation, Service Billing and SCE.com. The costs associated with developing the system requirements and database schema is captured in this cost category. Given these additional applications plus the extensive scope of the changes to them, we will need additional contractor resources to support these activities. We have estimated that the cost will increase from $0.53 million to $1.1 million in Scenario 16.

(f) Update Work Management Interface to Process Additional Meter Changes (I-7)

As detailed in the description for I-5, we will engage contractor resources to handle interface design and verification activities during 2006. In terms of the I-7 cost code, we estimate the cost for these activities will increase from $12,237 to $29,810.

(4) Operation and Maintenance [I-8 through I-16]

(a) Maintain Existing Hardware/Software that Translates Meter Reads into Bills (I-8)

As detailed in the description for I-5, we will engage contractor resources to handle interface design and verification activities during 2006. In terms of the I-8 cost code, we estimate the cost for these activities will increase from $20,452 to $177,377.

(b) Process Bill Determinant Data (I-9)

In Scenario 16, with the introduction of demand response rates, we will significantly increase the amount of usage data that is collected and processed. Instead of having one read and one time stamp per month for each account, we will now have 720 reads and 720 time stamps per month. With this volume of data, we expect that there will be additional usage validation failures than what we are projecting in Scenario 14. As such, we will need additional customer service representatives to manually process the accounts that the system is unable to process. Our personnel estimates include costs for sixteen FTEs in 2006, peaking at eighteen FTEs in 2007, and tapering off to fifteen FTEs for the 2011 to 2021 timeframe. Given the significant increase in personnel relative to Scenario 14, our cost estimates have increased from $3.8 million to $12.9 million.

In terms of our IT systems, we will also need to dedicate resources to define and develop processes which will support the rules that will determine whether data is processed by the system or whether it needs to be reviewed manually by a customer service representative. We will engage contractor resources to handle these activities during the 2006 to 2007 timeframe. We estimate the cost for these activities is expected to increase from $51,659 to $500,244.

(c) Contract Administration and Database Management (I-10)

As with Scenario 14, there are no incremental contract administration costs and the costs associated with infrastructure database management are included in I-16.

(d) Exception Processing (I-11)

As discussed in Scenario 14, our Billing organization will continue to incur costs related to manual processing of accounts that fail billing system validations. In Scenario 16, with the introduction of new demand response rates, we expect that there will be additional exceptions that result during the billing process due to the significant amount of data that will be processed in order to calculate a bill. We will also be handling additional activities associated with processing rate changes for customers who opt-out of their TOU default rate. As such, we expect to dedicate additional personnel to handle this manual processing. Our cost estimates indicate a $0.78 million difference between the costs in Scenarios 14 and 16.

In terms of our IT systems, we will need to dedicate additional personnel to defining and developing the process by which exceptions are handled. We estimate the cost for these activities will increase from $62,499 to $97,686.

(e) License/O&M Software Fees (I-12)

The descriptions of activities and the associated costs for these cost categories are the same as those described in Scenario 14.

(f) Ongoing Data Storage/Handling (I-13)

As with Scenario 14, the incremental costs associated with ongoing data storage and handling were charged to cost code I-16.

(g) Ongoing IT Systems (I-14)

As discussed in Scenario 14, cost code I-14 captures the costs related to the ongoing O&M for applications support, security administration, database administration support, maintenance and enhancement activities associated with the portfolio of applications that have been developed or enhanced to support AMI. In Scenario 16, we are introducing significant application enhancements, particularly those associated with the Usage Calculation system, in order to process the extensive volume of interval data. We will need to dedicate additional contract and SCE resources to support our portfolio. We have estimated that the labor and non-labor costs to perform these activities will increase from $8.4 million in Scenario 14 to $10.6 million in this scenario.

(h) Operating Costs (I-15)

The descriptions of activities and the associated costs for this cost code are the same as those described in Scenario 14.

(i) Server Replacements (I-16)

We expect to replace the computing systems hardware identified in cost category I-2 on the basis of a five year technology refresh cycle. As such, the hardware refresh would occur in 2011 and 2016. We did not include a final refresh in 2021 based on our assumption that the entire AMI system will be obsolete and need to be renewed with new technology and supporting infrastructure. Contractor resources and incremental SCE FTEs will need to be utilized to handle the design and installation of the new hardware. Incremental SCE labor costs for database management are also included in this cost category. Given that our computing systems are more extensive (as discussed in the description for cost code I-2) in this scenario than in Scenario 14, we will have more equipment subject to refresh in 2011 and 2016. As such, the costs for refreshing the computing systems and associated labor are estimated to increase from $8.6 million in Scenario 14 to $20.8 million in this scenario.

d) Customer Service Systems

(1) Start-up and Design

Appendix A to the Ruling does not identify any cost categories for customer service systems start-up or design. As such, any start-up or design activities have been classified as an installation cost below.

(2) Installation [CU-1 through CU-4]

In the installation area, there is one main difference between the Scenario 14 and Scenario 16 cost calculations. In Scenario 16, there will be additional charges related to cost category C-2 due to increased call volume resulting from rate change letters and "opt-out" inquiries to our Call Center. We expect to experience the same call volume level for mass communications and meter change letters in Scenario 16 as we did in Scenario 14. However, with the introduction of new rate schedules to facilitate customers' demand response, there will be additional customer communications that will ultimately lead to increased call volume. First, we will send Zone 4 customers a communication notifying them that their rate will be changed to a TOU rate schedule. We estimate that five percent of customers will call when notified that their rate is being changed. The five percent estimate is based on our experience with other communications in which rate modifications are included. Second, there will be customer calls related to opting out of the new rate. Our estimates assume twenty-seven percent of customers call about opting out and seventy percent of those that call will actually choose to opt-out. Third, we will receive additional customer calls related to their first series of bills after changing rates. We projected that our customers would go through a learning curve period in which a declining percentage of customers would call after each bill is received after switching to the new rate. Overall, we are expecting an increase of approximately 250,000 calls going from Scenario 14 to Scenario 16. This results in a total cost difference between the two scenarios of $1.6 million through 2021.

(3) Operation and Maintenance [CU-5 through CU-10]

As discussed previously, the most significant cost difference in the operation and maintenance area between Scenarios 14 and 16 is related to the mass media marketing costs, a portion of which are charged to cost code CU-10. The Customer Communications programs related to this scenario are expected to add a total of approximately $36 million in costs. Another $10 million in Customer Communications and Marketing costs related to this Scenario are, by definition included in cost code M-14 ("Customer Acquisition and marketing costs for new tariffs". These will be described below in the "Management and Miscellaneous Other" cost category.

In Scenario 16, beginning in 2007, the Call Center expects to receive customer calls with questions related to their first review of usage data presented on SCE.com. As previously discussed, we projected that our customers would go through a learning curve period in which a declining percentage of customers would call after each session on SCE.com to review usage data. The labor costs associated with these additional calls, which are charged to cost code CU-9, are estimated to be $11,000. Also, beginning in 2011, after the majority of AMI meter deployment is completed, we will begin to incur costs related to on-going customer education. The total estimated labor and non-labor costs, which are charged to cost category CU-8, are estimated to be $145,000.

As new rates are introduced in Scenario 16, we expect to experience an increase in the number of customer requests for rate analysis. Customers who are deciding whether to opt out may want to request a rate analysis to determine if the rate assigned to them is the best rate to stay on. Customers who decide to opt out of the rate may want to request a rate analysis to determine a more appropriate rate. The labor costs associated with these activities are in cost code CU-5 and are expected to increase by $225,000 over scenario 14 costs. For Scenario 16, our Major Customer Division will incur costs throughout 2007 and 2008 to provide coordination between account representatives and major customers for rate analysis "opt-out" and contract revisions. These costs are charged to cost category CU-5 and are estimated to be $225,000. We will also incur some relatively minor costs of $51,500 in cost category CU-8 related to developing materials for our customer account representatives and major customers.

In Scenario 16, our Customer Service organization will incur costs related to the development of market research surveys to learn about customers' wants and needs so that the information learned can be applied to enhance the website. Costs will also be incurred related to assisting major customers in learning how to use the website to access their usage data. We will also provide support to the Call Center by handling customer telephone calls regarding complex website related questions. The costs for these activities, which will be charged to cost codes CU-8 and CU-9, are estimated to be $5.3 million.

e) Management and Miscellaneous Other

The Management and "Other" cost categories make up $20.3 million of the $100.6 million in incremental cost differences between Scenario 14 and Scenario 16. The majority of this increase is attributable to the need for $10.5 million in Marketing and Customer Communications expenditures needed to retain 80% of the AMI metered customers on TOU rates given that they will have the option of "opting-out" either to return to their otherwise applicable "tiered rate" or to move to an optional CPP rate. The $10.5 million in marketing costs assigned to this cost category is in addition to the $36.3 million described in the previous section in cost code CU-10. The remainder of the management and miscellaneous cost increases for Scenario 16 are described in the following sections.

(1) Start-up and Design [M-1 through M-2]

These two cost codes relate to meter installations and were addressed in the Operational-only scenario. No additional costs would be incurred in this demand response scenario.

(2) Installation [M-3 through M-11]

Three of these Management cost codes (M-3, M-6 and M-8) were described in Scenario 14 above and have no incremental increases for the demand response scenarios.

(a) Employee Communications and Change Management (M-4)

We estimated $55,700 in additional cost related to all demand response scenarios over the duration of the analysis period for Web related costs associated with employee communications.

(b) Employee Training for New Systems and Rate Structures, Etc. (M-5)

Employee communication programs on the Web will add $253,000 to this cost code for all demand response scenarios. This will supplement the Billing Organization and JST training described in Scenario 14 under this cost code, and it relates primarily to assuring that customer contact personnel have a clear understanding of the rates and rate options being introduced under this scenario.

(c) Project Management Costs and Overhead (M-7)

The Billing Organization, Call Center and IT combined will have approximately $4.2 million in management and overhead cost increases under this scenario. This is for indirect management and supervision activities related to the increases in personnel for the functions described previously in the Information Technology (I-1 through I-16) and customer Services (CU-1 through CU-10) cost codes.

(d) Call Center Training Costs (M-10)

The Call Center would incur $349,000 in additional cost for specialized training to be able to respond to the large anticipated call volume brought about by the "opt-out" provisions of the TOU default rate. This is in addition to the "Customer Services" cost impacts discussed previously under cost codes CU-2, CU-8, and CU-9 above.

(3) Operation and Maintenance Costs (M-12 through M-15)

Our capital financing costs are included within the Meter Acquisition costs described previously, and we did not use the M-12 cost code to include any additional or alternative financing costs. Nor have we identified any cost for increased load during mid-peak and off-peak periods (M-13).

(a) Customer Acquisition and Marketing Costs for New Tariffs (M-14)

Incremental marketing and customer education costs in this cost code combined with those described in cost code CU-10 above make up the total customer communications program described previously. This cost code includes $10.5 million of the $46.8 million to be spent on marketing and customer education programs that will be necessary to secure seventy percent of the AMI metered customers on TOU rates, and keep them there for the duration of the analysis period

(b) Risk Contingencies (M-15)

Risk contingencies related to this scenario will be discussed in Section 3 below.

2. Benefits

Table 4-17 below summarizes the added benefits of this demand response scenario over those expected from Scenario 14, the partial deployment (Zone 4) operational-only scenario.

Demand response benefits for this scenario are similar to Scenario 3 except it applies only to Zone 4 customers. To determine demand response benefits, we used the Charles River Associates impact simulator model for SCE's Zone 4 adjusted for our cooling degree hours and air conditioning market penetration for that zone, as described in Volume 3, Scenario 3 and in Volume 2, Section III.

In addition to $28 million in Demand Response benefit, we expect to obtain $2.9 million in Customer Service benefits attributable to load reductions resulting from the availability of energy usage information being made available to customers on the Web (CB-8), An additional $1.2 million benefit from Web site equipment offsets (MB-1) reflect the avoided cost of future investments resulting from overall Web site infrastructure improvements needed to meet AMI program needs.

Table 4-17- Summary of Benefits for Scenario 16
($Millions in 2004 Pre-Tax Present Value Dollars)

Benefit Categories	Total
Systems Operations Benefits	$0.7
Customer Service Benefits	2.9
Management and Other Benefits	1.2
Demand Response DR-1 Benefits	28.0
Demand Response DR-2 Benefits	$3.0
TOTAL:	**$35.8**

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix C. For this scenario, the Value of Service loss is approximately $11 million ($2004 present value), reducing the total demand response benefit from $28 to $16 million.

3. Uncertainty and Risk Analysis

For Scenario 16, the total present value cost estimate is $262.5 million. The risk analysis for Scenario 16 is similar to that described for Scenario 17 that follows.

Uncertainties in the area of demand response and associated benefits are similar to those of Scenario 3, described in Volume 3.

4. Net Present Value Analysis

Table 4-18 summarizes the overall pre-tax costs and benefits of Scenario 16. Also shown is the after-tax NPV for this scenario on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period.

Table 4-18
Summary of Cost/Benefit Analysis for Scenario 16
($ Millions)

Costs	Benefits	Pre-tax PV	After Tax NPV	Rev. Req. NPV
$262.5	$63.0	($199.5)	($126.8)	($256.1)

Scenario 16 results in a negative Revenue Requirement Present Value of $256.1 million and does not support the implementation of partial AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the Scenario 16 analysis, plus the recovery of SCE's net investment in any removed meters, plus the rate of return and tax impacts of the AMI-related investments.

D. Scenario 17: Operational Plus Demand Response - CPP-F/CPP-V/RTP Default With Opt-out

Similar to Scenario 16 above, Scenario 17 assumes partial deployment of AMI meters to Zone 4 customers. The only difference between Scenario 16 and Scenario 17 is that the default rate in this scenario is CPP-F for residential customers, and CPP-V and RTP for C & I customers (TOU was the default rate for all customers in Scenario 16). Table 4-19 summarizes the costs and benefits of these two scenarios compared to the operational only Scenario 14.

Table 4-19
Comparison of Costs, Benefits, and NPV for Partial Deployment Scenarios 14, 16 and 17
(Millions of 2004 Pre-Tax Present Value Dollars)

	Cost	Benefit	Pre-Tax PV	After Tax NPV	Rev. Req. NPV
Scenario 14	$161.9	$30.8	($131.1)	($85.0)	($441.7)
Scenario 16	$262.5	$63.0	($199.5)	($126.8)	($256.1)
Scenario 17	$266.2	$111.6	($154.6)	($100.1)	($211.3)

The only cost difference between Scenario 16 and Scenario 17 is in the Marketing and Customer Communications programs, where we would expect to spend approximately $3.7 million more over the duration of the analysis period. This difference is entirely attributed to an increase of 350,000 subscribers (by 2021) to the SCE hosted "Envoy" CPP event notification service.[35] There are no other assumed operational cost differences between this scenario and those presented earlier in the Scenario 16 analysis.

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[35] The "Envoy" service was described previously in Volume 3, as part of the Scenario 4 discussion.

Benefits are expected to be $48.6 million higher under this scenario. This increase is due to the higher number of customers participating on CPP rates and the significantly more favorable response to CPP rates verses TOU rates under Scenario 16.

1. Costs by Cost Code

Table 4-20 summarizes the Scenario 16 and Scenario 17 costs by cost category.

Table 4-20
Summary of Costs for Scenario 16 vs. Scenario 17
(000s in 2004 Pre-Tax Present Value Dollars)

Cost Categories	Scenario 16	Scenario 17	Difference
Metering System Infrastructure	$85,134	$85,134	$0
Communications Infrastructure	7,819	7,819	0
Information Technology Infrastructure	87,752	87,752	0
Customer Service Systems	52,104	55,789	3,686
Management and Miscellaneous Other	29,703	29,703	0
TOTAL:	$262,512	$266,197	$3,686

As pointed out above the only difference in cost for Scenario 17 over Scenario 16 is in cost code CU-10 where the entire $3.7 million increase is attributable to the CPP event notification process.

2. Benefits

Table 4-21 summarizes the Scenario 17 benefits by category and compares them to Scenario 14 and Scenario 16 benefits. Scenario 17 benefits are the same as those described previously for Scenario 16, except the demand response benefits are expected to increase by $49 million (going from $28 million in Scenario 16 to $77 million in Scenario 17). Scenario 17 is similar to Scenario 16 except the default rate for Scenario 17 is CPP, whereas the default rate for Scenario 16 was

TOU. Scenario 17 is also similar to Scenario 4 except it applies only to Zone 4 customers.

Table 4-21
Summary of Benefits for Scenario 17
(000s in 2004 Pre-Tax Present Value Dollars)

Benefit Categories	Scenario 14	Scenario 16	Scenario 17
Systems Operations Benefits	$23,031	$23,031	$23,031
Customer Service Benefits	1,536	4,419	4,419
Management and Other Benefits	6,213	7,419	7,419
Demand Response DR-1 Benefits	-0-	25,000	67,500
Demand Response DR-2 Benefits	-0-	3,100	9,200
TOTAL:	$30,781	$62,696	$111,569

This scenario assumes that eighty percent of eligible Zone 4 customers are defaulted to CPP-F rates (residential) or CPP-V rates (C&I below 200kW) and those customers stay on those rates for the full duration of the business case. For the purposes of the analysis, we assumed that the customers opting-out of the CPP default rate would choose equally between a TOU rate and their otherwise applicable tariff. Our approach to estimating the demand response benefits is the same as for Scenario 4 except that we used our cooling degree hours and air conditioning market penetration for Zone 4.

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix C. For this scenario, the Value of Service loss is approximately $33 million ($2004 present value), reducing the total demand response benefit from $77 to $44 million.

3. <u>Uncertainty and Risk Analysis</u>

For Scenario 17, the total present value cost estimate is $266.2 million. We developed cost ranges as described in Scenario 14 and applied a Monte Carlo statistical analysis of costs that resulted in a range of $256.4 million to $291 million around the estimated cost of $266.2 million for this scenario. The statistical analysis indicates that our cost estimate has about a fifteen percent confidence. This means that the project has nearly an eighty-five percent chance of overrunning. Our preliminary cost estimates do not include contingency. However, based on our analysis we should consider a contingency of approximately $13 million in our final application to reduce the risk of overrun. This contingency amount is the difference between our cost estimate and the value at the ninety percent confidence level.

4. Net Present Value Analysis

Table 4-22 summarizes the overall pre-tax costs and benefits of Scenario 17. Also shown is the after-tax NPV for this scenario on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period.

Table 4-22
Summary of Cost/Benefit Analysis for Scenario 17
($ Millions)

Costs	Benefits	Pre-tax PV	After Tax NPV	Rev. Req. NPV
$266.5	$111.6	($154.6)	($100.1)	($211.3)

Scenario 17 results in a negative Revenue Requirement Present Value of $211.3 million and does not support the implementation of partial AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the scenario 17 analysis, plus the recovery of SCE's net investment in any removed meters, plus the rate of return and tax impacts of the AMI-related investments.

E. Scenarios 18 and 19: Operational Plus Demand Response - Current Tariff with Opt-in to CPP Pure (Scenario 18) and Opt-in to CPP-F and CPP-V (Scenario 19)

These two scenarios are prescribed in Attachment A of the Ruling as two of the five tariff structures to be analyzed in the partial deployment case.[36] Both our Scenario 18 and Scenario 19 assume the existing tariff structures will remain as the "default" tariff and customers will have the option of a CPP tariff in both scenarios. The only difference between Scenario 18 and Scenario 19 is that Scenario 18 offers the "CPP-Pure" rate option,[37] and Scenario 19 offers the "CPP-F" rate option to residential customers and the "CPP-V" rate option to small C&I customers. From an operational standpoint, SCE assumes no difference in costs between Scenarios 18 and 19. The only difference being in the level of Demand Response benefits we would expect to receive between the two options.

For comparison purposes, we will describe the cost differences of these two scenarios relative to Scenario 17, which had CPP-F/V/and RTP as "default" tariffs, with a twenty percent "opt-out" assumption. Thus the following incremental differences in costs and benefits reflect the savings we expect would result from making CPP "optional" rather than the "default" tariff. This difference significantly reduces the level of customer participation, thus reducing not only the cost, but the demand response we expect would result.

Table 4-23 compares the costs and benefits for Scenarios 18 and 19 to the costs and benefits we expect for Scenario 14 and Scenario 17.

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36 ALJ & AC Ruling dated 7/21/04, Attachment A, p.11

37 The "CPP-Pure" rate does not exist today. All current CPP rates fall back onto a time-of-use rate for non-critical peak periods. "CPP-Pure" would be a newly adopted rate schedule that would fall-back on the customers Otherwise Applicable Tariff (OAT) for non-critical peak periods.

Table 4-23– Comparison of Costs, Benefits, and NPV for Partial Deployment Scenarios 14, 17, 18 and 19 (Millions of 2004 Pre-Tax Present Value Dollars)					
	Cost	**Benefit**	**Pre-Tax PV**	**After Tax NPV**	**Rev. Req. NPV**
Scenario 14	$161.9	$30.8	($131.1)	($85.0)	($441.7)
Scenario 17	$266.2	$111.6	($154.6)	($100.1)	($211.3)
Scenario 18	$256.7	$56.3	($200.5)	($127.3)	($257.0)
Scenario 19	$256.7	$58.1	($198.6)	($126.2)	($255.1)

1. Costs by Cost Code

This section will describe the differences between the incremental costs by cost code for Scenario 17 and the incremental costs for Scenarios 18 and 19 (the costs for 18 and 19 being identical). These cost differences are summarized below in Table 4-24.

Table 4-24 Summary of Costs for Scenario 18 (000s in 2004 Pre-Tax Present Value Dollars)				
Cost Categories	**Scenario 17**	**Scenario 18**	**Scenario 19**	**Difference (17 v. 18 & 19)**
Metering System Infrastructure	$85,134	$85,134	$85,134	-0-
Communications Infrastructure	7,819	7,819	7,819	-0-
Information Technology Infrastructure	87,752	87,088	87,088	664
Customer Service Systems	55,789	51,459	51,459	4,331
Management and Miscellaneous Other	29,703	25,241	25,241	4,462
TOTAL:	$266,197	$256,740	$256,740	$9,457

a) Meter System Installation and Maintenance

For Scenarios 18 and 19, the costs are identical to those described in Scenario 17.

b) Communications Infrastructure

For Scenarios 18 and 19, the costs are identical to those described in Scenario 17.

c) Information Technology Infrastructure

In Scenarios 18 and 19, the cost differences relative to Scenario 17 are contained within 2 cost categories, I-9 and I-11. With the introduction of demand response rates, our Billing organization will see an increase in the amount of usage data that is collected and processed. As discussed previously, we expect that there will be additional usage validation failures and billing validation failures in demand response scenarios than what we would see in operational only scenarios. Additional customer service representatives are needed to manually process the accounts that the system is unable to process. The number of additional personnel that we need for this activity will vary between Scenarios 18 and 19 and Scenario 17. Our personnel estimates are driven by the number of customers on a rate requiring interval data. Since we anticipate a smaller number of customers will have rates requiring interval data in Scenarios 5 and 6, we anticipate that we will need less customer service representatives to handle this manual processing of accounts. For cost code I-9, we anticipate decreasing our cost estimate from $12.9 million in Scenario 17 to $12.6 million in Scenarios 18 and 19. For cost code I-11, our cost estimate decreases from $1.0 million in Scenario 17 to $0.6 million in Scenarios 18 and 19.

d) **Customer Service Systems**

Customer Service Systems costs are lower for Scenarios 18 and 19 in two specific areas:

- Marketing and customer costs in cost code CU-10 will be $3.2 million lower for these scenarios than for Scenario 17. This is due to the expected smaller number of customer participants and the reduced call volumes for proactive notification of CPP events to those customers who subscribe to the "Envoy" service hosted by SCE.[38]
- Call Center costs will be $0.9 million lower, due again to the lower number of active participants and lower anticipated call volume because there will be no "default" rate change notices and no "opt-out" provision under these scenarios. These costs are shown in cost code CU-2. Cost code CU-8 estimates for the Call Center are also lower for these two scenarios by $0.2 million. This is due to fewer calls expected during CPP events, and resulting bill impacts.

e) **Management and Miscellaneous Other Costs**

The Management and Other cost categories are $4.5 million lower for these two scenarios due primarily to $3.4 million less required for "customer acquisition and marketing" costs in cost code M-14, as a result of the less stringent requirements of the "Opt-in" assumption. Project Management costs (cost code M-7) are also expected to be $0.7 million lower in the Call Center and $0.2

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[38] For a more detailed description of the Envoy service and the associated costs see Scenario 4 costs in Volume 3, Section III above.

million lower in the Billing Organization over the duration of the analysis period. Call Center training costs (cost code M-10) will also be lower by $127,000, again due to the lower anticipated call volume and reduced training expenses (*i.e.*, fewer new employees).

2. <u>Benefits</u>

Scenario 18 is similar to Scenario 5 except that twenty-five percent of AMI metered residential and C&I customers are assumed to Opt-in to the CPP-Pure rate and remain there until 2021. We used the MMI model to determine the customer enrollment percentage in the first year and we used that same percentage for every year in the analysis. For the purposes of the analysis, we used the demand response behavior in the SPP for CPP-F as a proxy for CPP-Pure since the latter was not tested in the experiment.

Under Scenario 19, residential and small commercial/industrial customers below 200 kW could opt-in to either a CPP-F or CPP-V rate. Scenario 19 is similar to Scenario 6 except that eighteen percent of eligible customers would opt-in to CPP-F and six percent would opt-in to CPP-V. We used the MMI model to determine customer enrollment in CPP-F and CPP-V rates. We also assumed the same customer response to CPP-F rates in the SPP for this analysis for both CPP-F and CPP-V. For C&I customers, the SPP did not find statistically significant price elasticities. Therefore, we used the CPP-F price elasticity results from the SPP times a factor of twenty-five percent which is consistent with the literature for C&I price elasticity relative to residential price elasticity. The demand response benefits for Scenarios 18 and 19 as compared to Scenario 17 are shown in Table 4-25 below.

Table 4-25
Summary of Benefits for Scenario 17, 18 and 19
(Millions in 2004 Pre-Tax Present Value Dollars)

Benefit Categories	**Scenario 17**	**Scenario 18**	**Scenario 19**
Systems Operations Benefits*	$23.0	$23.0	$23.0
Customer Service Benefits*	4.4	4.4	4.4
Management and Other Benefits*	7.4	7.4	7.4
Demand Response DR-1 Benefits	67.5	18.8	20.5
Demand Response DR-2 Benefits	9.2	2.7	2.8
TOTAL:	$111.5	$56.3	$58.1

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix C. For Scenario 18, the Value of Service loss is approximately $10 million ($2004 present value), reducing the total demand response benefit from $22 to $12 million. For Scenario 19, the Value of Service loss is approximately $10 million ($2004 present value), reducing the total demand response benefit from $23 to $13 million.

Table 4-26 Tiered Default with Opt-in to CPP-Pure (Scenario 18) Current Tariff with Opt-in to CPP-F or CPP-V (Scenario 19)			
	No. of Meters (Customers) Year 2021	**Percent of Eligible Meters**	**Present Value ($ millions)**
Meters Eligible for TDRs	382,772		
Customers Enrolled on CPP-Pure (Scenario 18)	99,065	25	$22
Customers Enrolled on Tiered Rate (Scenario 18)	283,706	75	
Customers on CPP-F (Scenario 19)	75,082	18	$17
Customers on CPP-V (Scenario 19)	24,653	6	$6
Customers Enrolled on Tiered Rate (Scenario 19)	283,037	76	

3. Uncertainty and Risk Analysis

Scenarios 18 and 19 costs and operational benefit risks and analyses are the same as described Scenario 16.

Uncertainty and risks with respect to demand response benefits for Scenarios 18 and 19 are similar to Scenarios 5 and 6, respectively. (*See* Volume 3.)

4. Net Present Value Analysis

Table 4-28 summarizes the overall pre-tax costs and benefits of Scenarios 18 and 19. Also shown is the after-tax NPV for these scenarios on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period.

Table 4-27 Summary of Cost/Benefit Analysis for Scenarios 18 & 19 ($ Millions)					
Scenario	**Costs**	**Benefits**	**Pre-tax Present Value**	**After-Tax NPV**	**Rev. Req. Present Value**
Scenario 18	$256.7	$56.3	($200.5)	($127.3)	($257.0)
Scenario 19	$256.7	$58.1	($198.6)	($126.2)	($255.1)

Scenarios 18 and 19 both result in a negative Revenue Requirement Present Value of $257.0 million and $255.1 million, respectively. Neither of these two scenarios supports the implementation of a partial AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the Scenario 18 and 19 analyses, plus the recovery of SCE's net investment in any removed meters, plus the rate of return and tax impacts of the AMI-related investments.

F. Scenarios 20 and 21: Operational Plus Demand Plus Reliability - Current Tariff With Opt-In To CPP Pure (Scenario 20) and Opt-in to CPP-F and CPP-V (Scenario 21)

Scenario 20 is similar to Scenarios 18 and Scenario 21 is similar to Scenario 19 except that we include the full benefit of the ALC program in both scenarios as the reliability component. The ruling directs us to evaluate additional reliability benefits if the AMI is coupled with active use of ALC technology. The ALC program was included as part of our Long-Term Resource Procurement Plan in our 2005 Demand Response Proposals which were filed on October 15, 2004.[39] Both our Scenario 20 and Scenario 21 analyses assume the existing tariff structures will remain as the "default" tariff and customers will have the option of a CPP tariff in

39 SCE's (U 338-E) Demand Response Program Proposals for 2005-2008, in R. 04-04-003

both scenarios. Scenarios 20 and 21 differ from the Demand Response + Reliability Scenario 8 in that there is no adjustment for reducing the ALC program due to certain customers opting-in to a CPP rate. This is because the amount of customer overlap between a CPP rate and ALC just for Zone 4 is relatively small compared to Scenario 8. The only difference between Scenario 20 and Scenario 21 is that Scenario 20 offers the "CPP-Pure" rate option[40], and Scenario 21 offers the "CPP-F" rate option to residential customers and the "CPP-V" rate option to C&I customers. From an operational standpoint, SCE assumes no difference in costs between scenarios 20 and 21. The only difference is in the level of Demand Response benefits we would expect to receive between the two options.

1. Costs

For comparison purposes, we will describe the cost differences of these two scenarios relative to Scenarios 18 and 19. Table 4-28 summarizes the costs and cost differences by category.

Table 4-28- Summary of Costs for Scenario 18/19 vs. Scenario 20/21 (000s in 2004 Pre-Tax Present Value Dollars)

Cost Categories	Scenario 18/19	Scenario 20/21	Difference
Metering System Infrastructure	$85,134	$394,886	$309,752
Communications Infrastructure	7,819	7,819	-0-
Information Technology Infrastructure	87,088	87,088	-0-
Customer Service Systems	51,459	51,459	-0-
Management and Miscellaneous Other	25,241	25,241	-0-
TOTAL:	$256,740	$566,493	$309,752

The only cost code that changes when evaluating Scenarios 20 and 21 in relation to Scenarios 18 and 19 is cost code MS-12. In Scenarios 20 and 21, this

[40] The "CPP-Pure" rate does not exist today. All current CPP rates fall back onto a time-of-use rate for non-critical peak periods. "CPP-Pure" would be a newly adopted rate schedule that would fall-back on the customers Otherwise Applicable Tariff (OAT) for non-critical peak periods.

cost code captures the costs associated with the ALC program. The activities and associated costs are discussed in detail in the following section.

a) Meter System Installation and Maintenance

The most significant cost difference between Scenarios 20 and 21 and Scenario 18 and 19 is related to the ALC program. The ALC program modifies the existing air conditioning load control program to include an economic dispatch option. In addition, new digital and programmable thermostats are combined with the existing load control switches. Customers will be provided an incentive payment in exchange for allowing SCE to dispatch the program when most economically effective as well as when emergency situations arise.

In Scenarios 20 and 21, the cost estimates of $309.8 million, which are captured in cost code MS-12, are based upon the assumption that we will capture the full market potential of 500,000 customers that is projected for our new ALC program by 2011.[41] We are also assuming that the ALC program is approved in early 2005 and the equipment necessary to participate in the program is installed at approximately 142,000 of participating customers' homes or businesses within 2005.

The cost estimate of $309.8 million is comprised of the costs associated with equipment, installation, customer incentive payments and program administration that are incurred over the 2006 to 2021 timeframe. Beginning in 2006, we will incur equipment and installation costs associated with enrolling approximately 358,000 customers on the new ALC program. In terms of equipment costs, our estimates are based upon thirty percent of participating customers choosing to have a direct load control switch installed on their air conditioning unit.

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[41] This estimate assumes that the existing customers that are participating on our existing air conditioning cycling program will be migrated to the new program.

This installation will be handled by a contractor resource. The equipment and installation costs are estimated at $161 per customer.

For the remaining seventy percent of customers, we are assuming that a load control transceiver will be installed on the air conditioning unit. This transceiver will have the ability to control the customer's air conditioning unit by communicating with the customer's thermostat. The equipment costs associated with the thermostat and load control transceiver are estimated to be $150 per customer. In addition, we will incur installation costs. The contractor resource costs associated with installing a thermostat in a customer's home or business and a direct load control switch on their air conditioning unit are estimated to be $130.[42]

The majority of the $309.8 million cost estimate can be attributed to customer incentive payments. Customers who sign up on the ALC program will have the option of selecting from three different options during an event: 1) shedding 100 percent of their load, or 2) shedding fifty percent of their load, or increasing their temperature setting by 4º F. Incentive payments vary by the option selected and are paid only during the summer season, defined as the first Sunday in June to first Sunday in October. The average incentive payment, assuming a four ton per air conditioning unit and thirty days per month, is $86.40 for customers selecting the 100 percent load shed option. Customers opting for the fifty percent load shed option will receive on average $48.00. This fifty percent load shed incentive level is assumed to be the same as the incentive level associated with the 4º F set-back option. We also plan to incur minimal costs on an annual basis associated with program administration and customer communications.

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[42] In developing our preliminary analysis, we discovered an error associated with the cost calculation for this cost code. The overall estimate will be revised in our formal application as necessary.

b) **Communications Infrastructure**

The communications infrastructure costs for Scenarios 20 and 21 should be identical to those contained in Scenarios 18 and 19.[43]

c) **Information Technology Infrastructure**

The information technology infrastructure costs for Scenarios 20 and 21 should be identical to those contained in Scenarios 18 and 19.[44]

d) **Customer Service Systems**

The customer service systems costs are the same in Scenarios 20 and 21 as they are in Scenarios 18 and 19.

e) **Management and Miscellaneous Other**

The management and miscellaneous other costs for Scenarios 20 and 21 should be identical to those contained in Scenarios 18 and 19.[45]

2. **Benefits**

Table 4-29 shows the expected benefits by benefit category for Scenarios 18, 19, 20 and 21.

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[43] In the preliminary cost estimates for Scenarios 20 and 21, there appears to be a $89,175 cost difference between Scenarios 18 and 19 in cost codes C-1, C-10 and C-12. We are analyzing whether this cost difference is erroneous in the preliminary analysis and will update this number, as appropriate, in our final analysis.

[44] In the preliminary cost estimates for Scenarios 20 and 21, there appears to be a $1.67 million cost difference between Scenarios 18 and 19 in cost codes I-2, I-5, I-14, and I-16. We are analyzing whether this cost difference is erroneous in the preliminary analysis and will update this number, as appropriate, in our final analysis.

[45] In the preliminary cost estimates for Scenarios 20 and 21, there appears to be a $403,315 cost difference between Scenarios 18 and 19 in cost code M-7. We are analyzing whether this cost difference is erroneous in the preliminary analysis and will update this number, as appropriate, in our final analysis.

Table 4-29 Summary of Benefits for Scenario 20 (000s in 2004 Pre-Tax Present Value Dollars)				
Benefit Categories	**Scenario 18**	**Scenario 19**	**Scenario 20**	**Scenario 21**
Systems Operations	$23,031	$23,031	$23,031	$23,031
Customer Service	4,419	4,419	4,419	4,419
Management and Other	7,419	7,419	7,419	7,419
Demand Response	21,408	23,243	440,029	441,883
TOTAL:	$56,278	$58,112	$474,899	$476,753

a) <u>System Operations Benefits [SB-1 through SB-13]</u>

The system operations benefits in Scenarios 20 and 21 are identical to the benefits in Scenarios 18 and 19.

b) <u>Customer Service Benefits [CB-1 through CB-13]</u>

Customer service benefits in Scenarios 20 and 21 are identical to the benefits in Scenarios 18 and 19.

c) <u>Management and Other Benefits [MB-1 through MB-10]</u>

Management and other benefits in Scenarios 20 and 21 are identical to the benefits in Scenarios 18 and 19.

d) <u>Demand Response Benefits [DR-1 DR-2]</u>

Scenario 20 assumes that residential and C&I customers will opt in to the CPP-Pure rate and that a group of other residential customers, either on a TOU rate or their current rate, would enroll in ALC, providing a reliability feature. SCE used the MMI model to determine customer enrollment percentage in the first year and used that same percentage for every year in the analysis. For the purposes of the analysis, SCE used the demand response behavior in the SPP for

CPP-F as a proxy for CPP-Pure since the latter was not tested in the experiment. The demand response benefits are shown in Table 4-30 below.

Table 4-30
Current Default with Opt-in to CPP-Pure+Reliability (Scenario 20)

	No. of Meters (Customers) Year 2021	Percent of Eligible Meters	Present Value ($ millions)
Meters Eligible for TDRs	382,772		
Customers Enrolled on CPP-Pure	99,065	25	$22
Customers Enrolled on Current	283,706	75	$0
Customers Enrolled in AC cycling	500,000	0	$418
Total DR-1 Benefits			$386
Total DR-2 Benefits			$54
Total			$440

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B. For this scenario, we have not calculated the Value of Service loss for the ALC component of benefits. The demand response benefits from customers enrolled on CPP-Pure would decrease by $10 million from $22 million to $12 million.

Scenario 21 assumes that residential customers will opt in to CPP-F rates and C&I customers will opt in to CPP-V rates. We assume the full ALC program would provide a reliability feature. SCE used the MMI model to determine customer enrollment percentage in the first year and used that same percentage for every year in the analysis. The demand response benefits are shown in Table 4-31 below.

Table 4-31 Current Tariff with Opt-in to CPP F/V (Scenario 21)			
	No. of Meters (Customers) Year 2021	**Percent of Eligible Meters**	**Present Value ($ millions)**
Meters Eligible for TDRs	382,772		
Customers Enrolled on CPP-F	76,199	18	$17
Customers Enrolled on CPP-V	23,345	6	$5
Customers Enrolled on Current	283,227		$0
Customers Enrolled in AC cycling	500,000	0	$406
Total DR-1 Benefits			$429
Total DR-2 Benefits			$60
Total Demand Response Benefits			$489

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B. For this scenario, we have not calculated the Value of Service loss for the ALC component of benefits. The demand response benefits from customers enrolled on CPP-F/V would decrease by $11 million from $24 million to $13 million.

3. Uncertainty and Risk Analysis

Scenarios 20 and 21 costs and operational benefit risks and analysis are essentially the same as described in Scenario 16.

Uncertainty with respect to demand response benefits for Scenario 20 is the same as for Scenario 8 (*see* Volume 3). Uncertainty with respect to demand response benefits for Scenario 21 is similar to Scenario 6 (*see* Volume 3).

4. Net Present Value Analysis

Table 4-32 summarizes the overall pre-tax costs and benefits of Scenarios 20 and 21. Also shown is the after-tax NPV for these scenarios on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period.

Table 4-32
Summary of Cost/Benefit Analysis for Scenarios 20 & 21
($ Millions)

Scenario	Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. Present Value
Scenario 20	$567.8	$474.9	($92.9)	($63.4)	($153.1)
Scenario 21	$567.8	$476.8	($91.1)	($62.3)	($151.3)

Scenarios 20 and 21 both result in a negative Revenue Requirement Present Value of $153.1 million and $151.3 million respectively and neither of these two scenarios supports the implementation of a partial AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the scenario 20 and 21 analyses, plus the recovery of SCE's net investment in any removed meters, plus the rate of return and tax impacts of the AMI-related investments.

G. Scenarios 22 and 23: SCE's Alternative Scenarios Partial Deployments - TOU Default with Opt-out (Scenario 22) and CPP-F/CPP-V/RTP Default with Opt-out (Scenario 23)

Scenarios 22 and 23 are the Partial Deployment Case equivalents to Scenarios 9 and 10 in the Full Deployment case presented in Volume 2. Scenario 16 and Scenario 17 presented earlier in this volume were required by the Ruling and both included an assumption of twenty percent opt-out from their respective default rates (*i.e.*, TOU and CPP, respectively). As explained previously, SCE does not agree that it is reasonable to assume eighty percent customer participation on either the TOU default rate or the CPP default rates, given an opt-out alternative. We believe a more reasonable assumption to evaluate is a fifty percent opt-out rate and Scenarios 22 and 23 were designed to provide a comparative analysis based on this assumption. As such, we have re-analyzed Scenarios 16 and 17 with these recommended assumptions.

Table 4-33 summarizes the costs and benefits expected to result from these two scenarios compared to the two twenty percent opt-out equivalent scenarios.

Table 4-33
Comparison of Costs, Benefits and NPV for Scenarios 16, 17, 22 and 23
(000s in 2004 Pre-Tax Present Value Dollars)

	Scenario 16 20% Opt-Out TOU	Scenario 17 20% Opt-out CPP	Scenario 22 50% Opt-out TOU	Scenario 23 50% Opt-out CPP
Costs	\$262,512	\$266,197	\$260,114	\$261,324
Benefits	\$62,991	\$111,590	\$69,253	\$85,532
Pre-Tax PV	\$199,521	\$154,607	\$190,861	\$175,792

1. Costs

As was the case with Scenarios 16 and 17, the only operational cost differences between Scenarios 22 and 23 relate to the Marketing costs associated with critical-peak event notification (Cost code CU-10). Critical peak event notification costs are proportionate to the number of CPP rate participants, and are significantly higher for CPP default rate Scenarios 17 and 23 than for TOU default rate Scenarios 16 and 22. Scenario 17 Marketing costs are \$3.7 million higher than for Scenario 16 and Scenario 23 marketing costs are \$1.2 million higher than for Scenario 22.

Table 4-34 shows the costs by cost category for Scenarios 22 and 23 and compares them to Scenarios 16 and 17.

Table 4-34
Summary of Costs for Scenario 22
(000s in 2004 Pre-Tax Present Value Dollars)

Cost Categories	Scenario 16	Scenario 17	Scenario 22	Scenario 23
Metering System Infrastructure	$85,134	$85,134	$85,134	$85,134
Communications Infrastructure	7,819	7,819	7,819	7,819
Information Technology Infrastructure	87,752	87,752	85,483	85,483
Customer Service Systems (W/O Mktg.)	15,852	15,852	16,431	16,431
Marketing (CU-10 only)	36,252	39,938	36,970	38,180
Management and Miscellaneous Other	29,703	29,703	28,277	28,277
COST TOTAL:	$262,512	$266,197	$260,114	$261,324

a) Meter System Installation and Maintenance

For Scenarios 22 and 23, the costs are identical to those described in Scenarios 16 and 17.

b) Communications Infrastructure

The communications infrastructure costs for Scenarios 22 and 23 should be identical to Scenarios 16 and 17.

c) Information Technology Infrastructure (I-9 and I-11)

In Scenarios 22 and 23, the cost differences relative to Scenarios 16 and 17 are contained within 2 cost categories, I-9 and I-11. With regard to cost category I-9, the costs our Billing organization will incur are expected to decrease from $12.9 million to $10.4 million. We anticipate that we will need less analytical support toward the latter years of the analysis due to the lower participation rates for the fifty percent opt-out scenarios compared to the twenty percent scenarios.

For cost code I-11, the costs our Billing organization will incur to handle opt-out processing will increase as the number of customers opting-out increases from twenty percent to fifty percent. As such, our cost estimates increase from $1.0 million to $1.2 million.

d) **Customer Service Systems Costs (CU-2, CU-5, CU-8, CU-9, and CU-10)**

Call Center costs in cost code CU-2 for Scenarios 22 and 23 are expected to increase by $0.7 million (over the cost estimate for Scenarios 16 and 17) through 2021. Though we anticipate there will be fewer billing related calls and fewer critical peak pricing event calls into the Call Center under the fifty percent opt-out scenarios, we expect an overall increase in call volume due to the larger number of opt-out calls that are expected under Scenarios 22 and 23. The Billing Organization expects a $53,000 decrease in cost code CU-5 due to a decrease in the number of requests for billing analyses. The Call center expects decreased call volume relating to rate changes (CU-8) resulting in a cost decrease of $86,000 and a $6,000 decrease for questions relating to Internet usage data (CU-9).

The fifty percent opt-out assumption for TOU default Scenario 22 results in a $720,000 increase in marketing costs for CPP event notification (CU-10) over that expected in the twenty percent opt-out case (Scenario 3). This is because we have assumed that one-half of the TOU opt-outs will opt-in to the CPP rate. On the other hand, CPP event notification costs for Scenario 23 are expected to be $1.7 million less than that expected for Scenario 17. Again, these costs are a function of the number of CPP participants expected on each respective rate schedule (*see* Table 4-36 below).

e) Management and Other Costs (M-7, M-10 and M-14)

Project management and overhead costs in cost code M-7 are expected to increase by $650,000 for the Call Center and $218,000 for the Billing Organization in both of the fifty percent opt-out scenarios. This is directly related to the increase in opt-out calls, and billing calls anticipated for Scenarios 22 and 23 vs. Scenarios 16 and 17.

Customer acquisition and Marketing cost requirements are expected to be lower for Scenarios 22 and 23 than for Scenarios 16 and 17. This is expected to result in a decrease in marketing costs of $2.4 million in cost code M-14 for both scenarios 22 and 23 compared to scenarios 16 and 17.

2. Benefits

Table 4-35 shows the expected benefits by benefit category for Scenarios 16, 17, 22 and 23.

Table 4-35
Summary of Benefits for Scenarios 16, 17, 22 and 23
(000s in 2004 Pre-Tax Present Value Dollars)

Benefit Categories	Scenario 16	Scenario 17	Scenario 22	Scenario 23
Systems Operations	$23,031	$23,031	$23,031	$23,031
Customer Service Benefits	4,419	4,419	4,419	4,419
Management and Other	7,419	7,419	7,419	7,419
Demand Response	28,100	76,700	34,400	50,700
TOTAL:	62,969	111,569	69,269	85,569

Because we expect a significantly different customer mix on CPP verses TOU and Tiered rates in the fifty percent opt-out scenarios, we also expect a significantly different demand response. For the TOU default scenarios, demand response is estimated to be $6 million higher for Scenario 22 than for Scenario 16 because of higher assumed CPP participation. We assumed one-half of those opting-out of TOU rates in Scenario 22 would opt for the CPP rate schedule instead of the otherwise applicable tiered rates. On the other hand, the fifty percent CPP default Scenario 23 assumes lower CPP participation than for Scenario 17 with a eighty percent default participation assumption. Although we assume one-half of the opt-outs in Scenario 23 will actually opt-in to TOU rates rather than to tiered rates, the expected demand response for Scenario 23 is $26 million lower than for Scenario 17. Table 4-36 shows the expected customer participation rates on the alternative rate schedules for the four scenarios.

Table 4-36
Customer Participation by Rate Schedule
(Scenarios 16, 17, 22 and 23)

	Scenario 16	Scenario 17	Scenario 22	Scenario 23
Eligible Meters	382,772	382,772	382,772	382,772
Customers on TOU	306,217	38,277	191,386	95,693
Customers on CPP-F/V	38,277	306,217	95,693	191,386
Customers on Tiered	38,277	38,277	95,693	95,693

Scenario 22 assumes that fifty percent of eligible customers default to TOU rates and those customers stay on that rate for the full duration of the business case. Scenario 23 assumes that fifty percent of eligible customers default to the CPP-F or CPP-V rates, residential and C&I customers, respectively.

The demand response benefits for Scenarios 22 and 23 are computed differently than for previous partial scenarios but in the same way as Scenarios 9, 10, and 11. Under these scenarios, we used our portfolio approach to valuing the capacity and energy benefits from the planned load reductions. The avoided procurement cost associated with that load reduction is benefit category DR-1. We then added a fifteen percent reserve margin capacity credit as DR-2 for avoided reserve requirements. ALC also provided load reduction benefits as dispatchable resources and are valued accordingly as a DR-1 benefit. Demand response benefits for Scenarios 22 and 23 are illustrated in Tables 4-37 and 4-38 below.

Table 4-37 TOU Default with Opt-out (Scenario 23)			
	No. of Meters (Customers) Year 2021	Percent of Eligible Meters	Present Value ($ millions)
Meters Eligible for TDRs	382,772		
Customers Enrolled on CPP-F	95,693	25	
Customers Enrolled on Current	95,693	25	
Customers Enrolled on TOU	191,386	50	
Total DR-1 Benefits			$30.2
Total DR-2 Benefits			$4.1
Total Demand Response Benefits			$34.3

Table 4-38 CPP F/V Default with Opt-out (Scenario 23)			
Meters Eligible for TDRs	382,772		
Customers Enrolled on CPP F/V	191,386		
Customers Enrolled on TOU	95,693		
Customers Enrolled on Current	95,693		
Total DR-1 Benefits			$44.2
Total DR-2 Benefits			$6.5
Total Demand Response Benefits			$50.7

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix C. For Scenario 22, the Value of Service loss is approximately $5 million ($2004 present value), reducing the total demand response benefit from $34 to $29 million. For Scenario 23, the Value of Service loss is approximately $22 million ($2004 present value), reducing the total demand response benefit from $51 to $29 million.

3. Uncertainty and Risk Analysis

Scenario 22 and 23 costs and operational benefit risks and analysis are essentially the same as described for Scenarios 16 and 17, respectively.

As discussed in Volume 2, Section IV.5, because the statutory constraints of AB1-X are expected to be effective until 2014, we believe that an appropriate assumption is that these legal restrictions do apply and TDRs would not be effective until 2014. We considered the following sensitivity analyses. If the Ruling's required deployment window of 2006-2011 is carried out and TDRs cannot be implemented until 2014, then the demand response benefits would be substantially reduced. For Scenario 22, the present value of demand response benefits would decline from $34.4 million to $14.4 million. For Scenario 10, the present value of demand response benefits would decline from $50.7 million to $23.1 million.

4. Net Present Value Analysis

Table 4-39 summarizes the overall pre-tax costs and benefits of Scenarios 22 and 23. Also shown is the after-tax NPV for these scenarios on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period.

Table 4-39
Summary of Cost/Benefit Analysis for Scenarios 22 & 23
($ Millions)

Scenario	Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. Present Value
Scenario 22	$260.1	$69.3	($190.9)	($121.6)	($247.4)
Scenario 23	$261.3	$85.5	($175.8)	($112.7)	($232.4)

Scenarios 22 and 23 both result in a negative Revenue Requirement Present Value of $247.4 million and $232.4 million respectively and neither of these two scenarios supports the implementation of a partial AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the scenario 22 and 23 analyses, plus the recovery of SCE's net investment in any removed meters, plus the rate of return and tax impacts of the AMI-related investments.

V.

REVENUE REQUIREMENT AND RATE IMPACT ANALYSIS

The purpose of this section is to present our preliminary estimated net AMI-related revenue requirement and customer impacts for the years 2006 through 2021 for the partial deployment scenarios.[46] The preliminary revenue requirement presented in this section summarizes the operating expenses and investment-related costs identified in Section III and IV above. A cost recovery and ratemaking proposal to recover the AMI-related revenue requirements will be provided in our December, 2005 AMI filing.

Table 4-40 provides the estimated net AMI-related revenue requirement and average customer monthly dollar impacts for each of the partial deployment scenarios.

The estimated net AMI-related revenue requirement impacts by year for each scenario are calculated by subtracting the expected AMI benefits-related revenue requirement reductions from the estimated AMI cost related revenue requirement. For illustrative purposes, SCE has also calculated a customer monthly dollar impact by year for each. In order to calculate the average customer impacts, SCE utilized the total system retail sales forecast as presented in SCE's 2004 Long-Term Procurement Plan testimony filed on July 9, 2004 in R.04-04-003.

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[46] Due to the Ruling's prescribed 2006-2021 analysis period, the revenue requirement analysis does not include recovery of the remaining AMI-related plant investment as of the end of 2021, primarily for meters which would be installed or replaced between 2007 and 2020. These unrecovered costs [of approximately $190 million in unrecovered net plant for the full-deployment scenarios (Scenarios 1-11), and $19 million for the Zone 4 partial-deployment scenarios (Scenarios 14-23),] would be a continuing ratepayer obligation post-2021, although they also would be expected to provide a useful life past 2021, due to the underlying assets' fifteen-year life and their later in-service dates

A. AMI-related Revenue Requirement Increases

The AMI-related Revenue Requirement increase is comprised of two components: 1) New Meter Revenue Requirement; and 2) Stranded Cost Revenue Requirement. The New Meter Revenue Requirement represents the recovery of anticipated O&M expenses and capital costs associated with expected rate base amounts including depreciation, applicable taxes and return on rate base calculated at the Commission-authorized rate of return.[47] The return on rate base amounts included in the Revenue Requirements presented in Table 4-40 uses our currently authorized rate of return on rate base of 9.75 percent.

As discussed in Sections II and III of this volume, new meters will be placed in service over a five-year period (2006 through 2010). As the new meters are deployed, the existing or replaced meters will become stranded costs and the undepreciated balance, including anticipated negative net salvage, associated with these meters must be recovered in rate levels. As such, this revenue requirement analysis amortizes the stranded meters undepreciated net investment over the five-year new meter deployment period which will commence on January 1, 2006 and has reflected this proposal in this revenue requirement analysis. The net investment of the stranded meters will include plant and accumulated depreciation. The stranded cost revenue requirement also includes amortization, applicable taxes and an authorized return on rate base.

B. Expected Revenue Requirement Reductions

In order to estimate the net AMI-related revenue requirement impacts, the expected cost savings derived from the AMI benefit have been deducted from the AMI cost-related revenue requirement increase. The cost savings or revenue requirement reductions include: (1) Customer Service-related O&M reductions; (2)

[47] SCE has assumed a fifteen-year recovery period associated with the new meters.

existing meter revenue requirement reductions; and (3) procurement cost reductions due to demand response.

Table 4-40
AMI Revenue Requirement and Average Monthly Customer Impacts – (Partial AMI Deployment) - (000s of Dollars)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Scenario 12 - Partial-DR-RTEM-RTP																
AMI Meter Installation Revenue Requirements	5,983	5,281	3,833	3,832	3,825	3,881	136	136	135	133	135	132	133	132	131	124
Stranded Cost Revenue Requirement - 5 year	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meter Revenue Requirement in Rates	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Expected Procurement Reductions	(34,604)	(34,604)	(34,604)	(34,604)	(34,604)	(34,604)	(34,604)	(34,604)	(34,604)	(34,604)	(34,604)	(34,604)	(34,604)	(34,604)	(34,604)	(34,604)
Total Net AMI-related Rev Req Impact	**(28,621)**	**(29,322)**	**(30,771)**	**(30,772)**	**(30,779)**	**(30,722)**	**(34,468)**	**(34,467)**	**(34,468)**	**(34,471)**	**(34,468)**	**(34,471)**	**(34,470)**	**(34,472)**	**(34,473)**	**(34,479)**
Avg Monthly Customer Dollar Impact	**(0.50)**	**(0.50)**	**(0.52)**	**(0.51)**	**(0.51)**	**(0.50)**	**(0.55)**	**(0.54)**	**(0.54)**	**(0.53)**	**(0.53)**	**(0.52)**	**(0.51)**	**(0.51)**	**(0.50)**	**(0.50)**
Scenario 13 - Partial-DRR-RTEM-RTP																
AMI Meter Installation Revenue Requirements	58,303	57,602	56,154	56,153	56,146	56,202	52,456	52,457	52,456	52,453	52,456	52,453	52,454	52,452	52,451	52,445
Stranded Cost Revenue Requirement - 5 year	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meter Revenue Requirement in Rates	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Expected Procurement Reductions	(68,327)	(68,327)	(68,327)	(68,327)	(68,327)	(68,327)	(68,327)	(68,327)	(68,327)	(68,327)	(68,327)	(68,327)	(68,327)	(68,327)	(68,327)	(68,327)
Total Net AMI-related Rev Req Impact	**(10,024)**	**(10,725)**	**(12,173)**	**(12,174)**	**(12,181)**	**(12,125)**	**(15,871)**	**(15,870)**	**(15,871)**	**(15,874)**	**(15,872)**	**(15,875)**	**(15,873)**	**(15,875)**	**(15,876)**	**(15,883)**
Avg Monthly Customer Dollar Impact	**(0.17)**	**(0.18)**	**(0.21)**	**(0.20)**	**(0.20)**	**(0.20)**	**(0.25)**	**(0.25)**	**(0.25)**	**(0.24)**	**(0.24)**	**(0.24)**	**(0.24)**	**(0.23)**	**(0.23)**	**(0.23)**
Scenario 14 - PartialOperational-Zone4-Utility																
AMI Meter Installation Revenue Requirements	47,508	43,673	62,566	69,379	82,353	83,925	77,851	73,483	69,509	65,559	63,335	60,621	56,456	52,330	47,951	38,935
Stranded Cost Revenue Requirement - 5 year	10,580	10,165	9,369	6,532	11,441	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	0	(3,357)	(3,831)	(3,747)	(5,250)	(5,100)	(4,159)	(4,299)	(4,461)	(4,612)	(4,784)	(4,947)	(5,133)	(5,275)	(5,418)	(5,573)
Meter Revenue Requirement in Rates	282	359	471	471	471	471	471	471	471	471	471	471	471	471	471	471
Expected Procurement Reductions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Net AMI-related Rev Req Impact	**58,370**	**50,840**	**68,576**	**72,635**	**89,015**	**79,296**	**74,163**	**69,656**	**65,520**	**61,418**	**59,022**	**56,145**	**51,794**	**47,526**	**43,004**	**33,834**
Avg Monthly Customer Dollar Impact	**1.01**	**0.87**	**1.16**	**1.21**	**1.46**	**1.28**	**1.19**	**1.10**	**1.02**	**0.95**	**0.90**	**0.85**	**0.77**	**0.70**	**0.63**	**0.49**
Scenario 16 - Partial-DR-Zone4-TOU-Opt-20																
AMI Meter Installation Revenue Requirements	65,838	50,514	44,203	42,613	42,384	40,673	39,914	28,034	27,579	27,191	29,360	30,039	29,433	28,797	28,087	22,371
Stranded Cost Revenue Requirement - 5 year	10,580	10,165	9,369	6,532	11,441	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	(42)	(3,911)	(4,382)	(4,316)	(5,952)	(5,736)	(4,815)	(4,977)	(5,163)	(5,338)	(5,535)	(5,723)	(5,935)	(6,102)	(6,268)	(6,450)
Meter Revenue Requirement in Rates	282	359	471	471	471	471	471	471	471	471	471	471	471	471	471	471
Expected Procurement Reductions	0	(4,341)	(4,396)	(4,452)	(4,509)	(4,567)	(4,625)	(4,685)	(4,745)	(4,805)	(4,867)	(4,929)	(4,993)	(5,057)	(5,122)	(5,188)
Total Net AMI-related Rev Req Impact	**76,657**	**52,785**	**45,265**	**40,848**	**43,834**	**30,841**	**30,945**	**18,844**	**18,144**	**17,518**	**19,430**	**19,858**	**18,977**	**18,110**	**17,169**	**11,205**
Avg Monthly Customer Dollar Impact	**1.33**	**0.90**	**0.76**	**0.68**	**0.72**	**0.50**	**0.50**	**0.30**	**0.28**	**0.27**	**0.30**	**0.30**	**0.28**	**0.27**	**0.25**	**0.16**
Scenario 17 - Partial-DR-Zone4-CPP-Opt-20																
AMI Meter Installation Revenue Requirements	65,838	51,423	44,678	43,108	42,895	41,204	40,463	28,608	28,176	27,815	30,006	30,715	30,098	29,492	28,808	23,127
Stranded Cost Revenue Requirement - 5 year	10,580	10,165	9,369	6,532	11,441	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	(42)	(3,911)	(4,382)	(4,316)	(5,952)	(5,736)	(4,815)	(4,977)	(5,163)	(5,338)	(5,535)	(5,723)	(5,935)	(6,102)	(6,268)	(6,450)
Meter Revenue Requirement in Rates	282	359	471	471	471	471	471	471	471	471	471	471	471	471	471	471
Expected Procurement Reductions	0	(11,846)	(11,996)	(12,149)	(12,304)	(12,461)	(12,619)	(12,780)	(12,943)	(13,109)	(13,276)	(13,446)	(13,617)	(13,792)	(13,968)	(14,147)
Total Net AMI-related Rev Req Impact	**76,657**	**46,190**	**38,140**	**33,646**	**36,551**	**23,479**	**23,500**	**11,322**	**10,541**	**9,840**	**11,667**	**12,018**	**11,017**	**10,070**	**9,043**	**3,002**
Avg Monthly Customer Dollar Impact	**1.33**	**0.79**	**0.64**	**0.56**	**0.60**	**0.38**	**0.38**	**0.18**	**0.16**	**0.15**	**0.18**	**0.18**	**0.16**	**0.15**	**0.13**	**0.04**
Scenario 18 - Partial-DR-Zone4-CPP-Pure																
AMI Meter Installation Revenue Requirements	65,566	48,515	43,022	41,301	40,972	39,190	38,319	27,903	27,446	27,055	29,214	29,890	29,279	28,641	27,938	22,199
Stranded Cost Revenue Requirement - 5 year	10,580	10,165	9,369	6,532	11,441	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	(42)	(3,911)	(4,382)	(4,316)	(5,952)	(5,736)	(4,815)	(4,977)	(5,163)	(5,338)	(5,535)	(5,723)	(5,935)	(6,102)	(6,268)	(6,450)
Meter Revenue Requirement in Rates	282	359	471	471	471	471	471	471	471	471	471	471	471	471	471	471
Expected Procurement Reductions	0	(3,303)	(3,345)	(3,388)	(3,432)	(3,476)	(3,521)	(3,566)	(3,613)	(3,659)	(3,707)	(3,754)	(3,803)	(3,852)	(3,902)	(3,953)
Total Net AMI-related Rev Req Impact	**76,385**	**51,825**	**45,135**	**40,599**	**43,500**	**30,450**	**30,454**	**19,831**	**19,142**	**18,529**	**20,444**	**20,884**	**20,013**	**19,158**	**18,239**	**12,268**
Avg Monthly Customer Dollar Impact	**1.32**	**0.89**	**0.76**	**0.68**	**0.71**	**0.49**	**0.49**	**0.31**	**0.30**	**0.29**	**0.31**	**0.31**	**0.30**	**0.28**	**0.27**	**0.18**
Scenario 19 - Partial-DR-Zone4-CPP-FV																
AMI Meter Installation Revenue Requirements	65,566	48,515	43,022	41,301	40,972	39,190	38,319	27,903	27,446	27,055	29,214	29,890	29,279	28,641	27,938	22,199
Stranded Cost Revenue Requirement - 5 year	10,580	10,165	9,369	6,532	11,441	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	(42)	(3,911)	(4,382)	(4,316)	(5,952)	(5,736)	(4,815)	(4,977)	(5,163)	(5,338)	(5,535)	(5,723)	(5,935)	(6,102)	(6,268)	(6,450)
Meter Revenue Requirement in Rates	282	359	471	471	471	471	471	471	471	471	471	471	471	471	471	471
Expected Procurement Reductions	0	(3,582)	(3,629)	(3,676)	(3,724)	(3,773)	(3,822)	(3,873)	(3,923)	(3,975)	(4,027)	(4,080)	(4,134)	(4,188)	(4,244)	(4,300)
Total Net AMI-related Rev Req Impact	**76,385**	**51,546**	**44,851**	**40,312**	**43,208**	**30,153**	**30,153**	**19,525**	**18,831**	**18,213**	**20,124**	**20,559**	**19,682**	**18,821**	**17,898**	**11,922**
Avg Monthly Customer Dollar Impact	**1.32**	**0.88**	**0.76**	**0.67**	**0.71**	**0.49**	**0.48**	**0.31**	**0.29**	**0.28**	**0.31**	**0.31**	**0.29**	**0.28**	**0.26**	**0.17**
Scenario 20 - Partial-DRR-Zone4-CPP-Pure																
AMI Meter Installation Revenue Requirements	94,719	88,239	87,054	89,558	98,382	94,299	85,335	74,861	74,467	81,070	76,669	77,242	76,772	76,286	75,723	70,208
Stranded Cost Revenue Requirement - 5 year	10,580	10,165	9,369	6,532	11,441	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	(42)	(3,911)	(4,382)	(4,316)	(5,952)	(5,736)	(4,815)	(4,977)	(5,163)	(5,338)	(5,535)	(5,723)	(5,935)	(6,102)	(6,268)	(6,450)
Meter Revenue Requirement in Rates	282	359	471	471	471	471	471	471	471	471	471	471	471	471	471	471
Expected Procurement Reductions	(26,114)	(39,553)	(50,705)	(60,649)	(69,493)	(77,311)	(80,911)	(80,826)	(80,783)	(80,780)	(80,790)	(80,839)	(80,925)	(81,021)	(81,152)	(81,293)
Total Net AMI-related Rev Req Impact	**79,423**	**55,298**	**41,807**	**31,596**	**34,850**	**11,724**	**80**	**(10,471)**	**(11,007)**	**(4,576)**	**(9,184)**	**(8,848)**	**(9,616)**	**(10,366)**	**(11,227)**	**(17,062)**
Avg Monthly Customer Dollar Impact	**1.38**	**0.95**	**0.70**	**0.53**	**0.57**	**0.19**	**0.00**	**(0.17)**	**(0.17)**	**(0.07)**	**(0.14)**	**(0.13)**	**(0.14)**	**(0.15)**	**(0.16)**	**(0.25)**
Scenario 21 - Partial-DRR-Zone4-CPP-FV																
AMI Meter Installation Revenue Requirements	94,719	88,239	87,054	89,558	98,382	94,299	85,335	74,861	74,466	81,070	76,669	77,242	76,772	76,286	75,723	70,207
Stranded Cost Revenue Requirement - 5 year	10,580	10,165	9,369	6,532	11,441	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	(42)	(3,911)	(4,382)	(4,316)	(5,952)	(5,736)	(4,815)	(4,977)	(5,163)	(5,338)	(5,535)	(5,723)	(5,935)	(6,102)	(6,268)	(6,450)
Meter Revenue Requirement in Rates	282	359	471	471	471	471	471	471	471	471	471	471	471	471	471	471
Expected Procurement Reductions	(26,114)	(39,835)	(50,991)	(60,940)	(69,788)	(77,611)	(81,216)	(81,135)	(81,097)	(81,099)	(81,114)	(81,168)	(81,259)	(81,361)	(81,497)	(81,643)
Total Net AMI-related Rev Req Impact	**79,423**	**55,016**	**41,521**	**31,305**	**34,555**	**11,424**	**(225)**	**(10,780)**	**(11,322)**	**(4,895)**	**(9,508)**	**(9,177)**	**(9,951)**	**(10,706)**	**(11,572)**	**(17,414)**
Avg Monthly Customer Dollar Impact	**1.38**	**0.94**	**0.70**	**0.52**	**0.57**	**0.19**	**(0.00)**	**(0.17)**	**(0.18)**	**(0.08)**	**(0.14)**	**(0.14)**	**(0.15)**	**(0.16)**	**(0.17)**	**(0.25)**
Scenario 22 - Partial-DR-Zone4-TOU-Opt-50																
AMI Meter Installation Revenue Requirements	66,193	51,984	43,550	41,957	41,684	39,996	38,427	27,471	26,993	26,585	28,722	29,380	28,744	28,091	27,371	21,618
Stranded Cost Revenue Requirement - 5 year	10,580	10,165	9,369	6,532	11,441	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	(42)	(3,911)	(4,382)	(4,316)	(5,952)	(5,736)	(4,815)	(4,977)	(5,163)	(5,338)	(5,535)	(5,723)	(5,935)	(6,102)	(6,268)	(6,450)
Meter Revenue Requirement in Rates	282	359	471	471	471	471	471	471	471	471	471	471	471	471	471	471
Expected Procurement Reductions	(0)	(5,400)	(5,478)	(5,517)	(5,562)	(5,607)	(5,647)	(5,684)	(5,731)	(5,790)	(5,856)	(5,927)	(6,001)	(6,078)	(6,157)	(6,239)
Total Net AMI-related Rev Req Impact	**77,013**	**53,196**	**43,530**	**39,127**	**42,082**	**29,124**	**28,436**	**17,280**	**16,571**	**15,928**	**17,802**	**18,201**	**17,279**	**16,383**	**15,418**	**9,401**
Avg Monthly Customer Dollar Impact	**1.33**	**0.91**	**0.73**	**0.65**	**0.69**	**0.47**	**0.45**	**0.27**	**0.26**	**0.25**	**0.27**	**0.27**	**0.26**	**0.24**	**0.22**	**0.14**
Scenario 23 - Partial-DR-Zone4-CPP-Opt-50																
AMI Meter Installation Revenue Requirements	66,193	52,147	43,718	42,132	41,865	40,183	38,621	27,707	27,203	26,806	28,950	29,619	28,992	28,350	27,639	21,898
Stranded Cost Revenue Requirement - 5 year	10,580	10,165	9,369	6,532	11,441	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	(42)	(3,911)	(4,382)	(4,316)	(5,952)	(5,736)	(4,815)	(4,977)	(5,163)	(5,338)	(5,535)	(5,723)	(5,935)	(6,102)	(6,268)	(6,450)
Meter Revenue Requirement in Rates	282	359	471	471	471	471	471	471	471	471	471	471	471	471	471	471
Expected Procurement Reductions	(0)	(7,878)	(8,024)	(8,111)	(8,209)	(8,291)	(8,349)	(8,401)	(8,469)	(8,557)	(8,655)	(8,761)	(8,871)	(8,985)	(9,104)	(9,226)
Total Net AMI-related Rev Req Impact	**77,013**	**50,882**	**41,152**	**36,709**	**39,616**	**26,627**	**25,929**	**14,800**	**14,043**	**13,382**	**15,232**	**15,607**	**14,658**	**13,734**	**12,739**	**6,694**
Avg Monthly Customer Dollar Impact	**1.33**	**0.87**	**0.69**	**0.61**	**0.65**	**0.43**	**0.41**	**0.23**	**0.22**	**0.21**	**0.23**	**0.24**	**0.22**	**0.20**	**0.19**	**0.10**