BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Activities and Cost Recovery Mechanism	A.07-07-____ (Filed July 31, 2007)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) APPLICATION FOR APPROVAL OF ADVANCED METERING INFRASTRUCTURE DEPLOYMENT ACTIVITIES AND COST RECOVERY MECHANISM

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I.

INTRODUCTION

Pursuant to Rule 2.1 of the California Public Utilities Commission's Rules of Practice and Procedure, Southern California Edison Company ("SCE") hereby files this application seeking authorization to deploy SCE's advanced metering infrastructure ("AMI") solution, Edison SmartConnect™, to all residential and business customers under 200 kW during a five-year period beginning in 2008 and to recover the costs associated with the deployment activities.

The testimony in support of this application provides (i) an overview of SCE's policy objectives for Edison SmartConnect™; (ii) a detailed deployment plan, including estimates of the costs and benefits of Edison SmartConnect™ during the five-year deployment period; (iii) a cost benefit analysis of Edison SmartConnect™ full deployment, including assumptions for operational and demand response costs and benefits over the life of the project; and (iv) a revenue requirement and cost recovery mechanism for the $1.7 billion ($384.2 million in O&M expenses and $1,330.7 million in capital expenditures) in estimated Phase III costs.[1]

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[1] All costs and revenue requirements presented in this Application include $8 million of Phase III costs forecast to be recorded to the AMI Memorandum Account in 2007. In addition, SCE will include in the Edison SmartConnect™ revenue requirement $14.1 million of capital expenditures (plus $0.4 million of AFUDC) approved in D.07-07-042, but not allowed rate base treatment.

II.

ORGANIZATION OF SCE'S TESTIMONY

The testimony submitted in support of this application is comprised of five volumes of testimony:

Exhibit SCE-1: Policy

Executive Summary

Chapter I: Introduction

Chapter II: Edison SmartConnect™ Will Deliver Lasting Customer Value

Chapter III: Edison SmartConnect™ Satisifies State Energy Policy Objectives and Meets Minimum Functionality Requirements

Chapter IV: Edison SmartConnect™ Deployment is Cost Effective

Chapter V: Summary Of Requests

Exhibit SCE-2: Edison SmartConnect™ Deployment Plan

Chapter I: Introduction

Chapter II: Overview of Edison SmartConnect™ Deployment

Chapter III: Description of Key Deployment Areas of Edison SmartConnect™

Chapter IV: Contingency

Chapter V: Deployment Period Costs and Benefits

Exhibit SCE-3: Edison SmartConnect™ Cost Benefit Analysis

Chapter I: Introduction

Chapter II: Overview of Edison SmartConnect™ Financial Assessment

Chapter III: Edison SmartConnect™ Financial Assessment

Chapter IV: Societal Benefits (Non-Financial)

Chapter V: Analysis of Edison SmartConnect™ Revenue Requirements and Ratepayer Impacts

III.

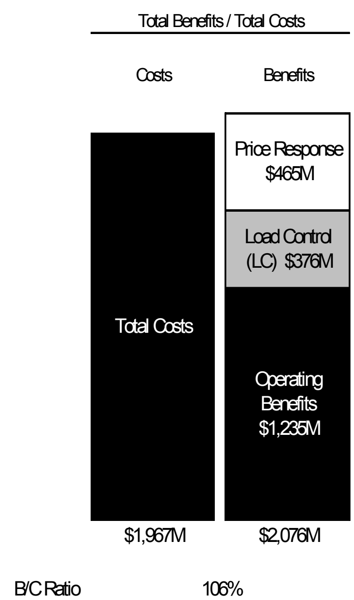
SUMMARY OF SCE'S EDISON SMARTCONNECT™ DEPLOYMENT PROPOSAL

In this Application, SCE requests authority to proceed with Phase III of its AMI deployment strategy. Where Phase I was dedicated to developing the functional requirements for the next generation of AMI metering systems that would deliver additional functionality and enhanced capabilities, and Phase II was focused on procuring the new AMI technologies, selecting a deployment contractor and validating the costs and benefits of the full deployment business case, Phase III involves the deployment of SCE's cost-effective AMI solution – Edison SmartConnect™ – to all residential and business customers under 200 kW in SCE's service territory.

In Phase III, SCE proposes to install state-of-the-art "smart" meters in every household and business under 200 kW throughout its service territory (approximately 5.3 million meters) over a five-year period beginning in 2008. These "smart" meters will be part of an advanced metering and telecommunications system that will enable powerful new tools to empower customers to manage their energy usage, enhance the efficiency of SCE's customer services, enable new services with smart technology, provide new rate alternatives, and provide a flexible, robust platform that can create additional future value for SCE's customers.

Edison SmartConnect™ is projected to deliver $109 million in net benefits (present value revenue requirement or PVRR) to customers over the life of the project, as shown in Table III-1 below. Operational savings are expected to cover approximately 63 percent of the related costs. Participation by residential and business customers in dynamic rates (Time of Use, Critical Peak Pricing), demand response programs (load control, pay-for-performance) and energy conservation is expected to provide sufficient additional benefits to justify the Edison SmartConnect™ project.

Table III-1
Edison SmartConnect™ Cost Benefit Analysis is Positive



The cost-effective business case for deploying Edison SmartConnect™ has been made possible by SCE's innovative and award-winning approach to AMI.[2] Driven by the state's vision to achieve advanced metering and demand response for all investor-owned utility customers by 2007, and faced with the reality that a cost effective business case was not possible with then-available AMI technology, in 2005 SCE began an ambitious, multi-phased strategy to collaborate with the AMI vendor community and international utility industry to spur development of AMI solutions with the additional functionality and capabilities needed to reduce costs and add benefits of a full AMI deployment. SCE's efforts, supported by the Commission through its approval of Phases I and II, have been successful in facilitating the development of a new generation of AMI solutions that will provide lasting value for SCE's customers. SCE's

[2] SCE's AMI deployment approach has gained international recognition, recently earning the Department of Energy's 2007 Smart Grid Implementation and Deployment Leadership Award. SCE's AMI Phase I was selected by The Utility Peer Network as the 2005/06 Best AMR Initiative in a North American Investor Owned Utility.

expected meter and telecommunications selections are commercially available technologies that meet SCE's business and technical requirements. The selected meter data management system is one of the leading software applications currently in deployment for utilities with similar AMI requirements.

The results of these efforts are reflected in SCE's current business case analysis, which now forecasts approximately $1 billion (PVRR) more net benefits than SCE's previous AMI business case analyses early in 2005.[3] These benefits arose primarily from SCE's work with the meter vendor community to enhance the capability, reliability, and useful life of the Edison SmartConnect™ meter.

Edison SmartConnect™ includes meter and communication functionality that (i) measures interval electricity usage and voltage; (ii) supports non proprietary, open standard communication interfaces with technology such as programmable communicating thermostats and device switches; (iii) improves reliability through remote outage detection at customer premises; (iv) improves service and reduces costs by remote service activation; (v) is capable of remote upgrades; (vi) is compatible with broadband over powerline use by third parties; (vii) supports contract gas and water meter reads; and (viii) incorporates industry-leading security capabilities. These functionalities far exceed the Commission's six functionality requirements to provide a powerful tool to support federal and state energy policy objectives.[4] They will also provide an enduring platform for continued innovation in meeting our customers' needs in the future.

The benefits to SCE's customers of Edison SmartConnect™ will be significant and long-term. By providing access to near real-time energy use and costs and by enabling dynamic pricing options for residential and business customers, Edison SmartConnect™ will be

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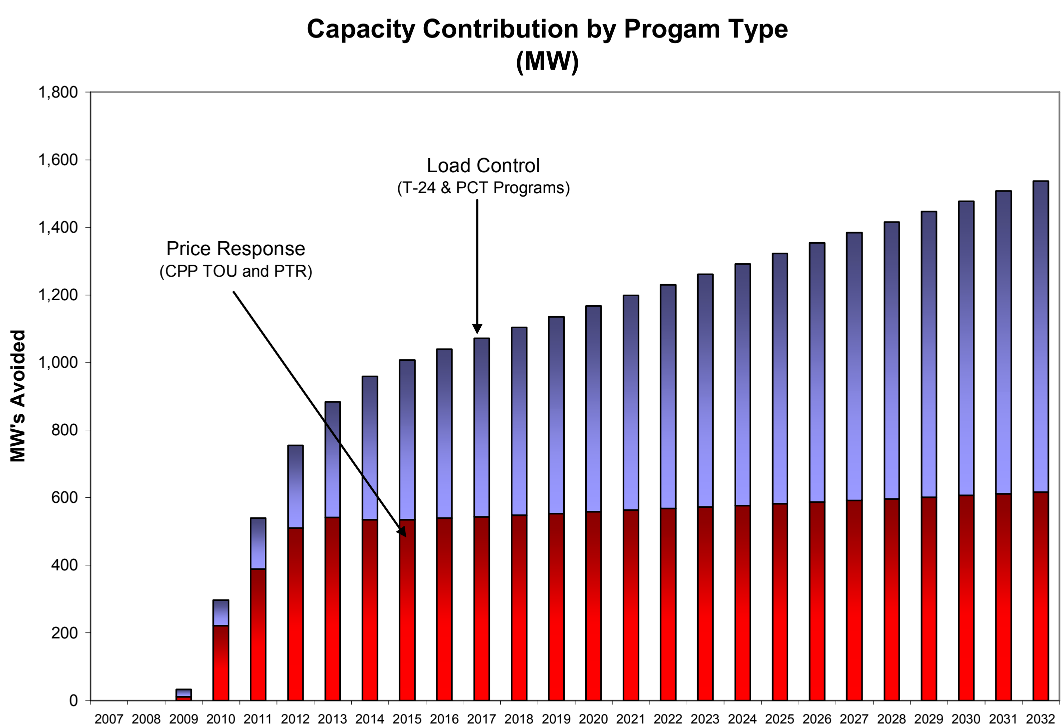
[3] From a negative $951 million Present Value Revenue Requirement (PVRR) in 2005 (*see* A.05-03-026) to a positive $109 million PVRR in 2007 for full AMI deployment.

[4] The Commission has already found that SCE's proposed AMI solution satisfies the Commission's minimum functionality requirements. *See* D.07-07-042 at Finding of Fact 1.

instrumental in managing peak consumption by providing incentives to customers to shift some of their usage to off-peak hours. Peak consumption is a key factor in determining generating capacity requirements and customer costs, so managing peak load is essential to controlling the need to build expensive new power plants.

Edison SmartConnect™ will enable all residential and business customers under 200 kW to participate in both reliability and price responsive load control and other demand response programs, potentially reducing peak demand by as much as 1,000 megawatts -- the entire output of a large power plant -- with related customer cost savings and environmental benefits, as shown in Figure III-1 below.

Figure III-1
Estimated Peak Demand Reduction for Price Response and Load Control Programs



Edison Smart Connect will also interface with "communicating" household devices, such as Title 24 compliant thermostats, lighting, electric dryers, other major appliances and pool pumps that can communicate with the new meters through a non-proprietary open Home Area Network and allow automatic adjustment of usage at customers' directions when power costs rise.

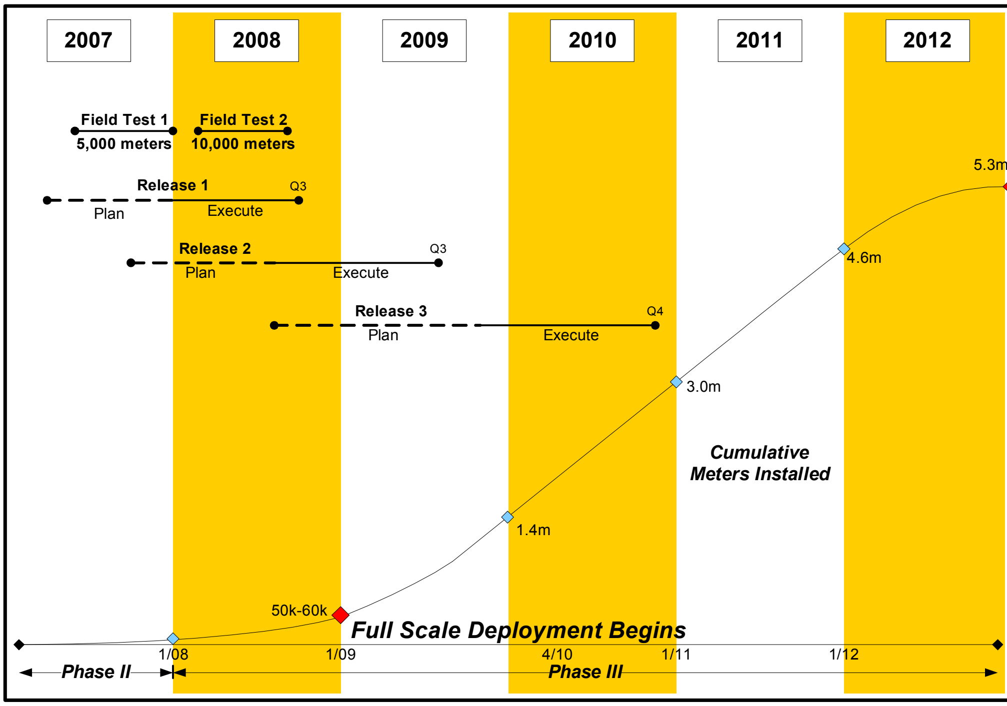
Edison SmartConnect™ will make doing business with SCE easier by allowing for convenient, remote service activation, tailored service bundles, and new billing and payment programs, among other customer services. Edison SmartConnect™ will also modernize SCE's infrastructure with smart technologies to improve electric power line grid planning, and operations and maintenance. It will improve outage response time and decrease operating costs with higher productivity. SCE anticipates that Edison SmartConnect™ will continue to provide a catalyst for industry innovation to realize the full potential of this new generation technology.

SCE's five-year deployment of Edison SmartConnect™ will entail a major technical, logistical and financial undertaking at an estimated cost of $1.7 billion. The annual incremental revenue requirement requested by SCE for the deployment costs amounts to about a one percent (1 %) increase to SCE's total revenue requirement.

As part of the detailed planning for deployment, SCE identified three distinct releases for all the systems development and integration work associated with Edison SmartConnect™. Phase III will begin with the execution of the first release, which involves the final development and testing of the Meter Data Management System and telecommunications network management system and integration with the customer billing system. A second field test of up to 10,000 additional meters will validate the installation processes and the expected revised version of the meter/telecom products based on Phase II engineering and development.

Phase III deployment will include two additional releases of the AMI system, each being slated to achieve a higher and more complex level of functionality than the previous one. These progressively increasing functionalities will be timed as illustrated in Figure III-2 below. This figure also shows the ramping-up of meter installations in relation to each respective Release and over time through June 2012 for the full Phase III deployment period.

Figure III-2
Timeline for AMI Phases II and III



Deployment of SCE's AMI project should be implemented without delay to begin achieving the benefits of Edison SmartConnect™. SCE requests approval of this Application by June of 2008 to remain on schedule for meter installation to begin in January 2009.

IV.

SUMMARY OF SCE'S RATEMAKING PROPOSAL

A. Overview

SCE requests approval to recover the revenue requirement associated with the costs of Phase III activities described in Exhibit SCE-2. These costs are estimated at approximately $384.2 million in O&M and $ 1,330.7 million in capital expenditures over the 2008 through 2012 deployment period.[5]

SCE proposes to establish an Edison SmartConnect™ balancing account mechanism to provide for recovery of the deployment period revenue requirement, which will include the recognition of operational benefits in the form of offsets to the Phase III costs.[6] This forecast revenue requirement will be recovered in distribution rates from 2009 through 2012 based on the estimated O&M expenses, depreciation, taxes, and authorized return on rate base amounts as derived from the estimated capital expenditures and the estimated operational benefits as set forth in this application. Beginning in 2009, the forecast Phase III revenue requirement for 2009 and any undercollection in the Base Revenue Requirement Balancing Account (BRRBA) arising from deployment activities in 2007 and 2008 will be reflected in SCE's total distribution rates. However, the proposed operation of the Edison SmartConnect™ balancing account mechanism (*i.e.*, only the actual revenue requirement recorded in the Edison SmartConnect™ balancing account will be transferred to the BRRBA each month) will ensure that no more and no less than

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[5] These amounts include $8 million of capital expenditures and O&M expense that will be incurred in 2007 associated with Phase II activities that did not receive authorization for recovery in the Commission's Phase II Decision No. 07-07-042. In addition, SCE will include in the Edison SmartConnect™ revenue requirement $14.1 million of capital expenditures (plus $0.4 million of AFUDC) approved in D.07-07-042, but not allowed rate base treatment.

[6] SCE proposes to flow back all Phase III capital-related benefits outside of the SmartConnect™ balancing account mechanism.

the reasonable revenue requirement associated with Phase III activities is ultimately collected from customers.

Assuming the Commission approves the scope of activities proposed by SCE and the forecast Phase III costs in this application, SCE's incurred costs that are consistent with the scope and within the cost levels adopted by the Commission should not be subject to an after-the-fact reasonableness review. If actual costs exceed the forecast, or if the scope of activities differs from what the Commission has approved, then SCE would file an application, or other appropriate procedural vehicle, to request approval of the activities and recovery of the additional costs subject to a traditional after-the-fact reasonableness review.

B. Interaction with Other Proceedings

1. Advanced Metering Infrastructure (AMI) Phase I and II (A.05-03-026 and A.06-12-026)

On December 1, 2005, the Commission issued Decision (D.) 05-12-001, "Decision Adopting Settlement For Funding Of Southern California Edison Company's Advanced Integrated Meter Project." The adopted Settlement set forth the scope, timing, and funding for Phase I AMI activities. Pursuant to D.05-12-001, SCE established the Advanced Metering Infrastructure Balancing Account (AMIBA) to provide for the recovery of up to $12 million over an 18-month period for costs related to SCE's Phase I AMI activities.[7] The AMIBA also may be expanded by Commission decisions to include the recorded costs associated with later phases of SCE's AMI project.

SCE initially projected that the Phase I AMI activities would occur over an 18-month time frame, from December 2005 through May 2007. Later, it became apparent that SCE would complete all Phase I AMI activities by year-end 2006. To expedite Phase II activities, SCE requested authority in Advice No. 2063-E to establish a memorandum account to track all

[7] The AMIBA was established through SCE Advice Filing No. 1937-E filed on December 6, 2005.

costs associated with SCE's AMI Phase II pre-deployment activities prior to a Commission decision in that proceeding. The Advanced Metering Infrastructure Memorandum Account for Phase II activities (AMIMA) became effective on December 22, 2006.[8]

In A.06-12-026, SCE's AMI Phase II application, SCE proposed to modify the current AMIBA to also record, in addition to Phase I AMI costs, up to $63.7 million in costs associated with Phase II AMI pre-deployment activities, from the effective date of a Commission decision in that proceeding through the completion of Phase II. Two sub-accounts within the existing AMIBA would separately record Phase I and Phase II AMI costs. In D.07-07-042, the Commission substantially adopted SCE's ratemaking proposal and set an authorized Phase II expenditure level of $45.220 million. This decision also allowed the continued use of the AMIMA to record costs of any SCE proposed Phase II activities that were not pre-approved by the Commission. SCE expects to record the revenue requirement of approximately $8 million in 2007 to the AMIMA for Phase II activities that were found to be deployment-related activities and thus were not pre-approved for recovery in D.07-07-042. Consistent with the Commission's direction in D.07-07-042 that it would be more appropriate to review Phase II costs that the Commission considers to be deployment-related costs in SCE's deployment application, SCE is requesting cost recovery of this $8 million in this application and has included the amount in the forecast revenue requirements.[9]

2. 2009 General Rate Case

SCE expects to file its 2009 GRC application later in 2007.[10] This application is being prepared on a "stand alone" basis; that is, the 2009 GRC application will not reflect the

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8 SCE plans to file an advice letter in the third quarter of 2007 requesting the expansion of the AMIMA to record Phase III costs prior to a Commission decision on this Application.

9 In addition, SCE will include in the Edison SmartConnect™ revenue requirement $14.1 million of capital expenditures (plus $0.4 million of AFUDC) approved in D.07-07-042, but not allowed rate base treatment. D.07-07-042 did allow $5.6 million of Phase II costs to be treated as rate base beginning in 2007 and those associated revenue requirements will be recorded into the existing AMIBA account.

10 SCE's 2009 GRC Notice of Intent was tendered on July 23, 2007.

costs or benefits associated with the Edison SmartConnect™ project. All incremental costs and benefits (or decremental costs) from the Edison SmartConnect™ project for the full deployment period of 2008 through 2012 will be addressed in this application so that neither the costs nor benefits of the Edison SmartConnect™ project will be double-counted.

SCE currently anticipates that the financial impacts of the Edison SmartConnect™ project will be incorporated into its 2012 GRC application; however, due to the overlap between the last year of Edison SmartConnect™ deployment of 2012 and the 2012 GRC test year, SCE may need to seek modifications to the SmartConnect™ balancing account mechanism in its 2012 GRC application.

C. <u>Edison SmartConnect Balancing Account Proposal</u>

SCE proposes the establishment of a new balancing account — the SmartConnect™ Balancing Account (SmartConnect™ BA) — to record the revenue requirement reflecting all capital and O&M costs and to capture the operational benefits associated with SCE's full deployment of advanced meters effective with a Commission decision in this proceeding. Each month, SCE will record into the SmartConnect™ BA:

1. Capital-related revenue requirements (debit), calculated on actual rate base amounts;
2. Actual incremental O&M costs (debit), calculated on recorded expenses; and
3. Calculated operational O&M benefits (credit).

The majority of the operational O&M benefits forecast by SCE are proportional to the number of meters installed and activated, and SCE therefore proposes to recognize all of the operational O&M benefits resulting from the Edison SmartConnect™ project monthly, as meters are activated. By crediting forecast O&M benefits as meters are activated, customers are assured of benefits as the project is implemented.[11]

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[11] SCE is requesting the ability to utilize project contingency for any unanticipated SmartConnect™ deployment costs, whether the unanticipated costs arise from increases in estimated costs, or from unanticipated delays in realizing benefits from the meter deployment.

For the Phase III deployment period of 2008 through 2012, the accrual of O&M benefits in proportion to meter activation average $1.3601 per activated meter per month as shown in Table IV-2 below. For Phase III, SCE will calculate the monthly O&M benefits to be recorded in the SmartConnect BA by multiplying the actual number of activated meters by $1.3601.

Table IV-2
Development of Average O&M Benefit per Active Meter Month
2008 – 2012

Line No.	Item	Total
1.	O&M Benefits as set forth in SCE-2	$188,382,728
2.	O&M Benefits net of pensions, PBOPs, & Results Sharing	$165,836,646
3.	Total Sum of Active Meter Months	121,929,279
4.	Avg. O&M Benefit per Active Meter Month (Line 4 = Line 2 divided by Line 3)	$1.3601

The capital benefits SCE forecasts to result from the Edison SmartConnect™ project are primarily related to: (1) avoided cost of electro-mechanical meters, (2) deferred projects (load control and price response projects), and (3) computers. All of these capital projects are, or will be, included in the Authorized Distribution Base Revenue Requirement (ADBRR) adopted in SCE's GRCs (2006 GRC for 2008, and 2009 GRC for 2009 – 2011), and the revenue requirement for each project will be credited back to customers based on the actual amounts associated with each and reflected in rates through annual advice letter filings.

Demand response-related benefits (*e.g.* avoided procurement costs) are not included in SCE's net revenue requirements since these benefits are dependent on customer behavior and should not be viewed as utility cost savings unless they materialize in the future.

SCE currently anticipates that it will address the operational benefit savings achieved after 2012 in its 2012 GRC.

D. <u>Reasonableness Review</u>

Assuming the Commission approves the scope of activities proposed by SCE and the forecast Phase III costs in this application, SCE's incurred costs that are consistent with the scope and within the cost levels adopted by the Commission should not be subject to an after-the-fact reasonableness review. If actual costs exceed the forecast, or if the scope of activities differs from what the Commission has approved, then SCE would file an application, or use other appropriate procedural vehicles, to request approval of the activities and recovery of the additional costs through a traditional after-the-fact reasonableness review.

Pursuant to the Commission-adopted process for reviewing other SCE balancing accounts, including the current AMIBA review procedures, SCE proposes that the recorded operation of the SmartConnect BA be reviewed by the Commission in SCE's annual ERRA reasonableness applications. This review of the SmartConnect BA will ensure that all entries to the account are stated correctly and are consistent with Commission decisions. Similar to the adopted Commission review procedures for Phase I and Phase II AMI costs, Commission review procedures for Phase III Edison SmartConnect™ costs should continue to be limited to ensuring that all recorded costs are associated with Phase III activities as defined and within the cost levels adopted by the Commission in this proceeding, in addition to ensuring that benefits are being captured according to the Commission-adopted methodology.

E. Forecast of Edison SmartConnect™ Revenue Requirements

The Edison SmartConnect™ Phase III 2008 – 2012 revenue requirements include all capital-related costs and incremental O&M expenses, net of forecast operational benefits, needed from customers to recover the cost of the Edison SmartConnect™ project. SCE's forecast Edison SmartConnect™ revenue requirement reflects Phase III funding of $384.2 million in O&M expenses and $1,330.7 million in capital expenditures over the period commencing January 1, 2008 through December 31, 2012. This revenue requirement is incremental to the revenue requirement reflected in either SCE's 2006 GRC or in SCE's 2009 GRC to be filed later in 2007.

Table IV-3
Summary of Edison SmartConnect™ Revenue Requirements
(O&M and Capital Costs, net of operating benefits)
Thousands of Dollars

Line No.	Item	2007	2008	2009	2010	2011	2012
1.	**Operating Revenues 1/**	**1,403**	**39,576**	**104,204**	**163,304**	**214,595**	**231,522**
2.	**Operating Expenses:**						
3.	O&M Expense	1,354	36,000	71,149	86,216	94,173	85,725
4.	O&M Benefits	-	(167)	(4,929)	(28,113)	(54,173)	(78,455)
5.	Uncollectible Expense	3	89	234	367	483	521
6.	Franchise Requirements	13	353	931	1,458	1,916	2,067
7.	Depreciation	631	7,659	23,867	44,705	65,586	79,904
8.	Taxes Other than Income	-	10	321	2,120	5,381	8,780
9.	Taxes Based on Income	(921)	(9,751)	(9,600)	8,686	28,040	44,514
10.	Total Operating Expenses	1,080	34,194	81,974	115,439	141,407	143,056
11.	**Net Operating Revenue**	**323**	**5,382**	**22,230**	**47,865**	**73,188**	**88,466**
12.	**Rate Base (Average)**	3,680	61,369	253,481	545,782	834,531	1,008,737
13.	**Rate of Return**	8.77%	8.77%	8.77%	8.77%	8.77%	8.77%

1/ Includes $14.1 million of approved Phase II capital expenditures not allowed rate base treament.

Upon Commission approval of this application, SCE will file an advice letter to implement changes to its preliminary statements and to include in distribution rates, effective January 1, 2009: (1) the forecast Edison SmartConnect™ 2009 revenue requirement of $104.2 million, (2) any undercollection in the BRRBA arising from deployment activities in 2008, (3) 2007 and 2008 recorded amounts in the AMIMA associated with the $8 million of costs that will be incurred in 2007 associated with Phase II activities that did not receive authorization for recovery in D.07-07-042, and (4) 2007 and 2008 recorded amounts in the AMIMA associated with the $14.1 million of capital expenditures (plus $0.4 million of AFUDC) approved in D.07-07-042 but not allowed rate base treatment. The total of these deployment revenue requirements is estimated to be $145.183 million. These revenue changes would be consolidated and made when all other previously authorized revenue changes are reflected in rates, consistent with the practice adopted for SCE's ERRA applications.

SCE will provide revised January 1, 2009 through 2012 SmartConnect™ revenue requirements to the Commission for approval at least 60 days in advance of the January 1 effective dates by Advice Letter.[12] In the annual advice filings, SCE will update the 2009 through 2012 SmartConnect™ revenue requirements to reflect the most recently adopted rate of return on rate base, franchise fees and uncollectible rates, and tax rates. SCE would then consolidate the changes in its distribution rates to reflect these updated SmartConnect™ revenue requirements in conjunction with other rate level changes in its annual August ERRA applications.

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[12] SCE currently expects that all of the Phase III costs and benefits, as adopted in a decision in this proceeding, will be incorporated into its 2012 GRC forecast; and therefore a separate rate change for the 2012 Phase III revenue requirement may not be necessary.

V.

SUMMARY OF REQUESTS

This application requests authorization to deploy SCE's advanced metering infrastructure ("AMI") solution, Edison SmartConnect™, to all residential and business customers under 200 kW during a five-year period beginning in 2008, and to recover the costs associated with the deployment activities. SCE respectfully requests that the Commission:

(i) Authorize SCE to proceed with full deployment of Edison SmartConnect™ to all residential and business customers under 200 kW (approximately 5.3 million meters) in SCE's service territory over a five-year period beginning in 2008;

(ii) Approve SCE's proposed budget for the Phase III activities of $1.7 billion;

(iii) Authorize SCE to implement a voluntary Programmable Communicating Thermostat (PCT) load control program throughout the five-year deployment period and conduct marketing, outreach and education on the dynamic rates and demand response program offerings for customers receiving the Edison SmartConnect™ meters;[13]

(iv) Authorize SCE to establish the Edison SmartConnect™ Balancing Account (SmartConnect™ BA) to provide for the recovery of Phase III recorded revenue requirements, which include recorded incremental costs and recognition of forecast operational O&M benefits, effective upon a Commission decision on this application;

(v) Authorize SCE to reduce its Authorized Distribution Base Revenue Requirement (ADBRR), on an annual basis, in order to recognize the Phase III capital benefits related to specific projects as set forth, and as adopted, in this proceeding, through the effective date of SCE's 2012 GRC Decision;

(vi) Authorize SCE to transfer the balance in the SmartConnect™ BA, each month, to the Base Revenue Requirement Balancing Account (BRRBA) to enable recovery, through distribution rate levels, of the actual Edison SmartConnect™-related revenue requirements for Phase III activities beginning on the effective date of a decision in this proceeding and continuing through the effective date of SCE's 2012 GRC Decision;

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[13] SCE intends to re-activate the CPP rate(s) used for the SPP via an advice filing, and offer existing TOU rates and re-activated CPP rates pending approval of a modified TOU and CPP rates in Phase II of SCE's 2009 GRC. SCE also plans to seek approval of a new Peak Time Rebate program in Phase II of SCE's 2009 GRC.

(vii) Approve the transfer from the AMIMA to the BRRBA 2007 and 2008 recorded revenue requirements associated with costs that will be incurred in 2007 associated with Phase II activities that did not receive authorization for recovery in D.07-07-042 and 2007 and 2008 recorded revenue requirements associated with the $14.1 million of capital expenditures (plus $0.4 million of AFUDC) approved in D.07-07-042 but not allowed rate base treatment;

(viii) Authorize recovery, through distribution rate levels, of SCE's forecast Edison SmartConnect™ revenue requirements for Phase III activities effective upon a Commission decision on this application and continuing through the effective date of SCE's 2012 GRC Decision;

(ix) Limit reasonableness review of the SmartConnect™ BA to ensure all recorded costs are associated with Phase III activities as defined and adopted by the Commission in this proceeding; and

(x) Grant such additional relief as the Commission finds just and reasonable.

VI.

STATUTORY AND PROCEDURAL REQUIREMENTS

A. Statutory and Procedural Authority

This application is made pursuant to the Commission's Rules of Practice and Procedure and the California Public Utilities Code. SCE's authority for this request is Sections 399.2, 451, 454, 491, 701, 728, and 729 of the Public Utilities Code of the State of California. SCE's request complies with Article 1, which specifies the procedures for the filing of documents, specifically:[14]

1. Form and size of tendered documents (Rule 1.5);
2. Title page (Rule 1.6);
3. Scope of Filing (Rule 1.7);
4. Signatures (Rule 1.8);
5. Service (Rule 1.9 - 1.10);
6. Verification (Rule 1.11); and
7. Tendering and Review of Document for Filing (Rule 1.13).

In addition, this request complies with Article 2 and Rule 3.2 of the Commission's Rules of Practice and Procedure, and prior decisions, orders and resolutions of this Commission.

B. SB 960 Requirements – Rule 2.1

Rule 2.1 requires that applications shall state "the proposed category for the proceeding, the need for hearings, the issues to be considered, and a proposed schedule." These requirements are discussed below.

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[14] Because this is a new application, no service list has yet been established. SCE is serving this application in accordance with the service directives on the service lists established for SCE's AMI Phase I application, A.05-03-026, and Phase II application, A.06-12-026.

1. Proposed Categorization

SCE proposes to characterize this proceeding as "ratesetting" as defined in Rule 1.3(e).

2. Need for Hearings and Proposed Schedule for Resolution of Issues

SCE's proposed schedule assumes that there will be evidentiary hearings and briefing, although SCE anticipates that many of the issues addressed in this application may be resolved through settlement or stipulation or through written comments, depending on whether intervening parties dispute factual issues.

If the Commission believes evidentiary hearings are necessary, then SCE proposes the following schedule, which will enable SCE to remain on schedule for meter installations to begin in January 2009.

SCE files Application	July 31, 2007
Daily Calendar Notice Appears	August 2007
Protests Due	August 30, 2007
Reply to Protests	September 10, 2007
Prehearing Conference	September 20, 2007
ORA and Intervenors File Opening Testimony	November 20, 2007
Rebuttal Testimony Due	December 21, 2007
Hearings	January 14-26, 2008
Concurrent Opening Briefs Due	February 26, 2008
Concurrent Reply Briefs Due	March 14, 2008
Commission Issues Proposed Decision Due	May 13, 2008
Comments to Proposed Decision Due	June 3, 2008
Replies to Comments to Proposed Decision	June 9, 2008
Commission issues Final Decision	June 12, 2008

3. Issues to be Considered

The issues to be considered in this proceeding are described above and set forth in much greater detail in SCE's testimony in support of this application. Major issues include:

a) Whether to approve the deployment of Edison SmartConnect™ and funding; and

b) Whether to adopt SCE's proposed ratemaking treatment for the recovery of the costs associated with the Edison SmartConnect™ deployment activities.

4. Legal Name and Correspondence

Southern California Edison Company is an electric public utility organized and existing under the laws of the State of California. The location of SCE's principal place of business is 2244 Walnut Grove Avenue, Post Office Box 800, Rosemead, California 91770. SCE's attorneys in this matter are Jennifer T. Shigekawa, Bruce A. Reed and Janet S. Combs. Correspondence or communications regarding this application should be addressed to:

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Telephone: (626) 302-1524
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To request a copy of this application, please contact:

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C. Articles of Incorporation – Rule 2.2

A copy of SCE's Certificate of Restated Articles of Incorporation, effective on March 2, 2006, and presently in effect, certified by the California Secretary of State, was filed with the Commission on March 14, 2006, in connection with Application No. 06-03-020, and is by reference made a part hereof.

Certain classes and series of SCE's capital stock are listed on a "national securities exchange" as defined in the Securities Exchange Act of 1934 and copies of SCE's latest Annual Report to Shareholders and its latest proxy statement sent to its stockholders has been filed with the Commission.

D. <u>Authority to Increase Rates – Rule 3.2</u>

Rule 3.2 requires that applications for authority to increase rates, or to implement changes that would result in increased rates, contain the following data.

1. <u>Balance Sheet and Income Statement – Rule 3.2(a)(1)</u>

Appendix A to this application contains copies of SCE's balance sheet as of March 31, 2007, and income statement for the period ended March 31, 2007, the most recent period available.

2. <u>Present and Proposed Rates – Rule 3.2(a)(2) and (a)(3)</u>

The cost recovery mechanism proposal and the projected impact on rates are summarized in Section IV above and discussed in Exhibit SCE-5.

3. <u>Description of SCE's Service Territory and Utility System – Rule 3.2(a)(4)</u>

Because this submittal is not a general rate application, this requirement is not applicable.

4. <u>Summary of Earnings – Rule 3.2(a)(5)</u>

Rule 3.2(a)(5) requires:

> A summary of earnings (rate of return summary) on a depreciated rate base for the test period or periods upon which applicant bases its justification for an increase.

SCE's 2007 Summary of Earnings is attached hereto as Appendix B.

5. Depreciation – Rule 3.2(a)(7)

Because this submittal is not a general rate application, this requirement is not applicable.

6. Capital Stock and Proxy Statement – Rule 3.2(a)(8)

Because this submittal is not a general rate application, this requirement is not applicable.

7. Statement Pursuant to Rule 3.2(a)(10)

Rule 3.5(a)(10) requires the applicant to state whether its request is limited to passing through to customers "only increased costs to the corporation for the services or commodities furnished by it." This application seeks only to pass through to SCE's customers the costs incurred by SCE in Phase III of its AMI program.

8. Service of Notice – Rule 3.2(b), (c) and (d)

A list of the cities and counties affected by the rate changes resulting from this application is attached as Appendix C. The State of California is also an SCE customer whose rates would be affected by the proposed revisions.

As provided in Rule 3.2(b) – (d), notice of filing of this application will be: (1) mailed to the appropriate officials of the state and the counties and cities listed in Appendix C; (2) published in a newspaper of general circulation in each county in SCE's service territory within which the rate changes would be effective; and (3) mailed to all customers affected by the proposed changes.

E. Service List

SCE is serving this application and its exhibits on all parties on the Commission's service lists for proceedings A.05-03-026 and A.06-12-026.

VII.

CONCLUSION

SCE has attached to this application all of the data required to support it and will provide orally or in writing any other information the Commission finds necessary to act on it. SCE respectfully requests that the Commission review and resolve this application on the schedule proposed above.

Dated this 31st day of July 2007, at Rosemead, California.

Respectfully submitted,

SOUTHERN CALIFORNIA EDISON COMPANY

/s/ Lynda L. Ziegler

By: Lynda L. Ziegler
Senior Vice President

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BRUCE A. REED
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/s/ Janet S. Combs

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July 31, 2007

VERIFICATION

I am an officer of the applicant corporation herein, and am authorized to make this verification on its behalf. I am informed and believe that the matters stated in the foregoing document are true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed this **31st day of July, 2007**, at Rosemead, California.

/s/ Lynda L. Ziegler

Lynda L. Ziegler
Senior Vice President
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Activities and Cost Recovery Mechanism	A.07-07-____ (Filed July 31, 2007)

NOTICE OF AVAILABILITY OF SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) APPLICATION FOR APPROVAL OF ADVANCED METERING INFRASTRUCTURE DEPLOYMENT ACTIVITIES AND COST RECOVERY MECHANISM

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Dated: July 31, 2007

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Activities and Cost Recovery Mechanism	A.07-07-____ (Filed July 31, 2007)

NOTICE OF AVAILABILITY OF SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) APPLICATION FOR APPROVAL OF ADVANCED METERING INFRASTRUCTURE DEPLOYMENT ACTIVITIES AND COST RECOVERY MECHANISM

In accordance with Rule 1.9(c) of the Commission's Rules of Practice and Procedure, Southern California Edison Company ("SCE") provides copies of this Notice of Availability to all parties on the service lists in proceedings A.05-03-026 and A.06-12-026 of the availability of the following documents on SCE's website at http://www.sce.com/smartconnect:

1. SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) APPLICATION FOR APPROVAL OF ADVANCED METERING INFRASTRUCTURE DEPLOYMENT ACTIVITIES AND COST RECOVERY MECHANISM, filed July 31, 2007;

2. EXHIBIT SCE-1: TESTIMONY OF SOUTHERN CALIFORNIA EDISON COMPANY IN SUPPORT OF ADVANCED METERING INFRASTRUCTURE DEPLOYMENT ACTIVITIES AND COST RECOVERY MECHANISM (Volume 1 – Policy);

3. EXHIBIT SCE-2: TESTIMONY OF SOUTHERN CALIFORNIA EDISON COMPANY IN SUPPORT OF ADVANCED METERING INFRASTRUCTURE DEPLOYMENT ACTIVITIES AND COST RECOVERY MECHANISM (Volume 2 – Deployment Plan);

4. EXHIBIT SCE-3: TESTIMONY OF SOUTHERN CALIFORNIA EDISON COMPANY IN SUPPORT OF ADVANCED METERING INFRASTRUCTURE DEPLOYMENT ACTIVITIES AND COST RECOVERY MECHANISM (Volume 3 – Financial Assessment and Cost Benefit Analysis);

5. EXHIBIT SCE-4: TESTIMONY OF SOUTHERN CALIFORNIA EDISON COMPANY IN SUPPORT OF ADVANCED METERING INFRASTRUCTURE

DEPLOYMENT ACTIVITIES AND COST RECOVERY MECHANISM (Volume 4 – Demand Response);

6. EXHIBIT SCE-5: TESTIMONY OF SOUTHERN CALIFORNIA EDISON COMPANY IN SUPPORT OF ADVANCED METERING INFRASTRUCTURE DEPLOYMENT ACTIVITIES AND COST RECOVERY MECHANISM (Volume 5 – Cost Recovery Proposal)

The documents are presented in Adobe Acrobat (PDF) searchable format and can be viewed on-line, printed or saved to your hard drive.

Copies may be obtained by sending a request to:

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Respectfully submitted,

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By: /s/ Janet S. Combs

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Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

Dated: July 31, 2007

APPENDIX A
Southern California Edison Company's
Balance Sheet and Income Statement

SOUTHERN CALIFORNIA EDISON COMPANY

BALANCE SHEET

MARCH 31, 2007

A S S E T S

(Unaudited)

(Millions of Dollars)

UTILITY PLANT:	
Utility plant, at original cost	$19,385
Less - Accumulated depreciation and decommissioning	(4,937)
	14,448
Construction work in progress	1,578
Nuclear fuel, at amortized cost	176
	16,202
OTHER PROPERTY AND INVESTMENTS:	
Nonutility property - less accumulated provision for depreciation of $650	1,033
Nuclear decommissioning trusts	3,220
Other Investments	80
	4,333
CURRENT ASSETS:	
Cash and equivalents	85
Restricted cash	53
Margin and collateral deposits	36
Receivables, including unbilled revenues, less reserves of $26 for uncollectible accounts	878
Accrued unbilled revenue	296
Inventory	234
Accumulated deferred income taxes - net	294
Derivative assets	172
Regulatory assets	443
Other current assets	195
	2,686
DEFERRED CHARGES:	
Regulatory assets	2,874
Derivative assets	12
Other long-term assets	484
	3,370
	$26,591

SOUTHERN CALIFORNIA EDISON COMPANY

BALANCE SHEET

MARCH 31, 2007

CAPITALIZATION AND LIABILITIES

(Unaudited)

(Millions of Dollars)

CAPITALIZATION:	
Common stock	$2,168
Additional paid-in capital	385
Accumulated other comprehensive loss	(13)
Retained Earnings	3,255
Common shareholder's equity	5,795
Preferred and preference stock	
not subject to redemption requirements	929
Long-term debt	5,162
	11,886
CURRENT LIABILITIES:	
Short-term debt	120
Long-term debt due within one year	334
Accounts payable	635
Accrued taxes	182
Accrued interest	113
Counterparty collateral	50
Customer deposits	207
Book overdrafts	164
Derivative liabilities	32
Regulatory liabilities	1,163
Other current liabilities	575
	3,575
DEFERRED CREDITS:	
Accumulated deferred income taxes - net	2,672
Accumulated deferred investment tax credits	110
Customer advances	162
Derivative liabilities	30
Power purchase contracts	29
Accumulated provision for pensions and benefits	825
Asset retirement obligations	2,778
Regulatory liabilities	3,157
Other deferred credits and other long-term liabilities	1,025
	10,788
Minority interest	342
	$26,591

SOUTHERN CALIFORNIA EDISON COMPANY

STATEMENT OF INCOME

THREE MONTHS ENDED MARCH 31, 2007

(Unaudited)

(Millions of Dollars)

OPERATING REVENUE	$2,222
OPERATING EXPENSES:	
Fuel	310
Purchased power	317
Provisions for regulatory adjustment clauses - net	289
Other operation and maintenance expenses	601
Depreciation, decommissioning and amortization	276
Property and other taxes	55
Total operating expenses	1,848
OPERATING INCOME	374
Interest income	11
Other nonoperating income	17
Interest expense - net of amounts capitalized	(107)
Other nonoperating deductions	(11)
INCOME BEFORE TAX AND MINORITY INTEREST	284
INCOME TAX	53
MINORITY INTEREST	38
NET INCOME	193
DIVIDENDS ON PREFERRED AND PREFERENCE STOCK - NOT SUBJECT TO MANDATORY REDEMPTION	13
NET INCOME AVAILABLE FOR COMMON STOCK	$180

APPENDIX B
Southern California Edison Company's
2006 Summary of Earnings

Southern California Edison
Summary of Earnings
2007 GRC-Related Adopted Revenue Requirement [1/]
Thousands of Dollars

Line No.	Item	Total
1.	**Base Revenues**	3,915,200
2.	**Expenses:**	
3.	Operation & Maintenance	1,812,704
4.	Depreciation	826,047
5.	Taxes	588,142
6.	Revenue Credits	(167,481)
7.	Total Expenses	3,059,412
8.	**Net Operating Revenue**	855,788
9.	**Rate Base**	9,758,124
10.	**Rate of Return**	8.77%

1/ D.06-05-016/Advice Letter 2054-E-A
Includes one SONGS 2&3 refueling and maintenance outage

APPENDIX C
List of Cities and Counties

SOUTHERN CALIFORNIA EDISON COMPANY

Citizens or some of the citizens of the following counties and municipal corporations will or may be affected by the changes in rates proposed herein.

COUNTIES

Fresno	Kings	Orange	Tuolumne*
Imperial	Los Angeles	Riverside	Tulare
Inyo	Madera	San Bernardino	Ventura
Kern	Mono	Santa Barbara	

MUNICIPAL CORPORATIONS

Adelanto	Cudahy	La Habra	Ojai	Santa Monica
Agoura Hills	Culver City	La Habra Heights	Ontario	Santa Paula
Alhambra	Cypress	La Mirada	Orange	Seal Beach
Aliso Viejo	Delano	La Palma	Oxnard	Sierra Madre
Apple Valley	Desert Hot Springs	La Puente	Palm Desert	Signal Hill
Arcadia	Diamond Bar	La Verne	Palm Springs	Simi Valley
Artesia	Downey	Laguna Beach	Palmdale	South El Monte
Avalon	Duarte	Laguna Hills	Palos Verdes Estates	South Gate
Baldwin Park	El Monte	Laguna Niguel	Paramount	South Pasadena
Barstow	El Segundo	Laguna Woods	Perris	Stanton
Beaumont	Exeter	Lake Elsinore	Pico Rivera	Tehachapi
Bell	Farmersville	Lake Forest	Placentia	Temecula
Bell Gardens	Fillmore	Lakewood	Pomona	Temple City
Bellflower	Fontana	Lancaster	Port Hueneme	Thousand Oaks
Beverly Hills	Fountain Valley	Lawndale	Porterville	Torrance
Bishop	Fullerton	Lindsay	Rancho Cucamonga	Tulare
Blythe	Garden Grove	Loma Linda	Rancho Mirage	Tustin
Bradbury	Gardena	Lomita	Rancho Palos Verdes	Twentynine Palms
Brea	Glendora	Long Beach	Rancho Santa Margarita	Upland
Buena Park	Goleta	Los Alamitos	Redlands	Victorville
Calabasas	Grand Terrace	Lynwood	Redondo Beach	Villa Park
California City	Hanford	Malibu	Rialto	Visalia
Calimesa	Hawaiian Gardens	Mammoth Lakes	Ridgecrest	Walnut
Camarillo	Hawthorne	Manhattan Beach	Rolling Hills	West Covina
Canyon Lake	Hemet	Maywood	Rolling Hills Estates	West Hollywood
Carpinteria	Hermosa Beach	McFarland	Rosemead	Westlake Village
Carson	Hesperia	Mission Viejo	San Bernardino	Westminster
Cathedral City	Hidden Hills	Monrovia	San Buenaventura	Whittier
Cerritos	Highland	Montclair	San Dimas	Woodlake
Chino	Huntington Beach	Montebello	San Fernando	Yorba Linda
Chino Hills	Huntington Park	Monterey Park	San Gabriel	Yucaipa
Claremont	Indian Wells	Moorpark	San Jacinto	Yucca Valley
Commerce	Industry	Moreno Valley	San Marino	
Compton	Inglewood	Murrieta	Santa Ana	
Corona	Irvine	Newport Beach	Santa Barbara	
Costa Mesa	Irwindale	Norco	Santa Clarita	
Covina	La Canada Flintridge	Norwalk	Santa Fe Springs	

*SCE provides electric service to a small number of customer accounts in Tuolumne County and is not subject to franchise requirements.

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 NOTICE OF AVAILABILITY OF SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) APPLICATION FOR APPROVAL OF ADVANCED METERING INFRASTRUCTURE DEPLOYMENT ACTIVITIES AND COST RECOVERY MECHANISM AND SUPPORTING TESTIMONY on all parties identified on the attached service list(s). Service was effected by one or more means indicated below:

Transmitting the copies via e-mail to all parties who have provided an e-mail address. First class mail will be used if electronic service cannot be effectuated.

Executed this 31st day of July 2007, at Rosemead, California.

/s/ Meraj Rizvi

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Application No.:	07-07-
Exhibit No.:	SCE-1
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SOUTHERN CALIFORNIA EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

EDISON SMARTCONNECT™ DEPLOYMENT FUNDING AND COST RECOVERY

Volume 1 –Policy

Before the

Public Utilities Commission of the State of California

Rosemead, California

July 31, 2007

LAW #1366512

EDISON SMARTCONNECT™ DEPLOYMENT FUNDING AND COST RECOVERY

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EXECUTIVE SUMMARY

Southern California Edison Company (SCE) requests authority to proceed with Phase III of its Advanced Metering Infrastructure (AMI) deployment strategy. Whereas Phase I was dedicated to developing the functional requirements for the next generation of AMI metering systems that would deliver additional functionality and enhanced capabilities, and Phase II was focused on procuring the new AMI technologies, selecting a deployment contractor and validating the costs and benefits of the full deployment business case, Phase III involves the deployment of SCE's cost-effective AMI solution – Edison SmartConnect™ – to all residential and business customers under 200 kW in SCE's service territory. Edison SmartConnect™ is expected to deliver $109 million in net present value benefits to customers over the life of the project.[1]

Scope of SCE's Proposal and AMI Capabilities

In Phase III, SCE proposes to install state-of-the-art "smart" meters in every household and business under 200 kW throughout its service territory (approximately 5.3 million meters) over a five-year period beginning in 2008. These "smart" meters will be part of an advanced metering and telecommunications system that provides customers powerful new tools to manage their energy usage, enhances the customer service efficiency, enables new services with smart technology, provides new rate alternatives, and provides a flexible, robust platform that can create additional future value for SCE's customers. Edison SmartConnect™ provides a powerful tool to support federal and state energy policy objectives.

Edison SmartConnect™ includes meter and communication functionality that (i) measures interval electricity usage and voltage; (ii) supports non proprietary, open standard communication interfaces with technology such as programmable communicating thermostats and device switches; (iii) improves reliability through remote outage detection at customer premises; (iv) improves service and reduces costs by remote service activation; (v) is capable of remote upgrades; (vi) is compatible with

[1] SCE's cost benefit analysis is summarized in Section IV.A of this volume, and described in detail in Volume 3 (Exhibit SCE-3) of this application.

broadband over powerline use by third parties; (vii) supports contract gas and water meter reads; and (viii) incorporates industry-leading security capabilities. These attributes far exceed the six functionality requirements recognized by the Commission and will also accommodate continued innovation in meeting our customers' needs in the future.

Edison SmartConnect™ will provide residential and business customers access to their near real-time energy use and costs, enabling dynamic pricing options that will provide incentives for the first time for many of these customers to shift their usage from on-peak to off-peak hours. On-peak energy usage is a key factor in determining generating capacity requirements and affects the need to build expensive new power plants. With residential and business customers under 200 kW participating in reliability, price responsive load control, and other demand response programs, peak demand could be reduced by as much as 1,000 megawatts -- the entire output of a large power plant -- with related customer cost savings and environmental benefits.

Edison Smart Connect will interface with "communicating" household devices, such as thermostats, lights, electric dryers, major appliances and pool pumps through a non-proprietary open Home Area Network. It will also allow customers to automatically adjust their usage when power costs rise.

Edison SmartConnect™ will enhance customer services by allowing for convenient, remote service activation, tailored service bundles, and new billing and payment programs. Edison SmartConnect™ will also modernize SCE's infrastructure with smart technologies to improve electric power line grid planning, improve outage response, and reduce operations and maintenance expense. Edison SmartConnect™ should continue to provide a catalyst for industry innovation using this new generation technology.

<u>Costs and Benefits</u>

In 2005, SCE faced the reality that the then-available AMI technology did not support a cost-effective solution. Thus, SCE began an ambitious, multi-phased strategy to collaborate with AMI vendors and other utilities to spur the development of the additional AMI capabilities needed to deploy a cost-effective system. SCE's efforts, supported by the Commission through its approval of Phases I and

II, have facilitated the development of a new generation of AMI technology that will provide lasting value for SCE's customers. SCE's expected meter and telecommunications selections are commercially available technologies that meet SCE's business and technical requirements. The selected meter data management system is one of the leading software applications currently in deployment for utilities with similar AMI requirements.

Deployment of Edison SmartConnect™ was made cost effective by SCE's innovative and award-winning approach to AMI.[2] The results of these efforts are reflected in SCE's current business case analysis, which now forecasts approximately $1 billion more net present value benefits than SCE's previous analyses conducted early in 2005.[3] These benefits arose primarily from SCE's work with the meter vendor community to enhance the capability, reliability and useful life of the Edison SmartConnect™ meter.

The five-year deployment period for Edison SmartConnect™ is a major technical, logistical and financial undertaking at an estimated cost of $1.7 billion, corresponding to about a one percent annual increase to SCE's total revenue requirement over the five-year deployment period. Ultimately, Edison SmartConnect™ is expected to deliver $109 million in net present value benefits to customers over the life of the project. Operational savings are expected to provide approximately 63 percent of the benefits, with the remainder of benefits provided through the participation of residential and business customers in dynamic pricing (Time of Use, Critical Peak Pricing), demand response (load control, pay-for-performance), and energy conservation programs.

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[2] SCE's AMI deployment approach has gained international recognition, recently earning the Department of Energy's 2007 Smart Grid Implementation and Deployment Leadership Award. SCE's AMI Phase I was selected by as the 2005/06 Best AMR Initiative in a North American Investor Owned Utility.

[3] From a negative $951 million Present Value Revenue Requirement (PVRR) in 2005 (*see* A.05-03-026) to a positive $109 million PVRR in 2007 for full AMI deployment.

Summary of SCE's Requests

SCE seeks authority to:

(i) proceed with deployment of Edison SmartConnect™ to all residential and business customers under 200 kW (approximately 5.3 million meters) in SCE's service territory over a five-year period beginning in 2008 at an estimated cost of $1.7 billion;

(ii) implement a voluntary Programmable Communicating Thermostat (PCT) load control program throughout the five-year deployment period and to conduct marketing, outreach and education on the dynamic rates and demand response program offerings for customers receiving the Edison SmartConnect™ meters;[4]

(iii) establish the Edison SmartConnect™ Balancing Account (SmartConnect™ BA) to provide for the recovery of Phase III recorded revenue requirements, which include recorded incremental costs and recognition of forecast operational O&M benefits, effective upon a Commission decision on this application;

(iv) reduce its Authorized Distribution Base Revenue Requirement (ADBRR), on an annual basis, in order to recognize the Phase III capital benefits related to specific projects as set forth, and as adopted, in this proceeding, through the effective date of SCE's 2012 GRC Decision;

(v) transfer the balance in the SmartConnect™ BA, each month, to the Base Revenue Requirement Balancing Account (BRRBA) to enable recovery, through distribution rate levels, of the actual Edison SmartConnect™-related revenue requirements for Phase III activities beginning on the effective date of a decision in this proceeding and continuing through the effective date of SCE's 2012 GRC Decision;

(vi) transfer from the AMIMA to the BRRBA the 2007 and 2008 recorded revenue requirements associated with costs that will be incurred in 2007 associated with Phase II activities that did not receive authorization for recovery in D.07-07-042 and 2007

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[4] SCE intends to offer Edison SmartConnect customers existing TOU and CPP rates pending approving of modified rates and a new Peak Time Rebate program in Phase II of SCE's 2009 GRC.

and 2008 revenue requirements associated with the $14.1 million of capital expenditures (plus $0.4 million of AFUDC) approved in D.07-07-042 but not allowed rate base treatment;

(vii) recover, through distribution rate levels, SCE's forecast Edison SmartConnect™ revenue requirements for Phase III activities effective upon a Commission decision on this application and continuing through the effective date of SCE's 2012 GRC Decision; and

(viii) limit reasonableness review of the SmartConnect™ BA to ensure all recorded costs are associated with Phase III activities as defined and adopted by the Commission in this proceeding.

Deployment of SCE's AMI project should be implemented without delay to begin achieving the benefits of Edison SmartConnect™ as early as 2009. SCE requests approval of this Application by no later than June of 2008 to remain on schedule for meter installation to begin in January 2009.

I.

INTRODUCTION

The purpose of this Volume 1 (Exhibit SCE-1) is to provide an overview of the policy objectives SCE seeks to achieve with its Edison SmartConnect™ project.

Section I is introductory, and describes the organization of Volume I with a general description of the other volumes of testimony. Section II describes SCE's objectives for AMI, which are focused on empowering customers to manage their energy costs and providing customers with new services through smart technology. Section III discusses how Edison SmartConnect™ meets the state's energy policy objectives and the Commission's functionality requirements. Section IV summarizes SCE's requests in this Application. SCE concludes this volume in Section V.

Volume 2 (Exhibit SCE-2) presents SCE's proposed plan for deploying Edison SmartConnect™, including the schedule, estimated costs and benefits during the Deployment Period (2008-2012) and risk mitigation strategies. Volume 3 (Exhibit SCE-3) contains SCE's cost benefit analysis of Edison SmartConnect™ over the life of the project, and demonstrates why the project is justified. Volume 4 (Exhibit SCE-4) contains a detailed discussion of SCE's proposed demand response programs and dynamic rates for the Deployment Period, including reasonable participation rate assumptions and forecast benefits. Volume 5 (Exhibit SCE-5) sets forth SCE's proposed cost recovery mechanism for Edison SmartConnect™ deployment costs.

II.

EDISON SMARTCONNECT™ WILL DELIVER LASTING CUSTOMER VALUE

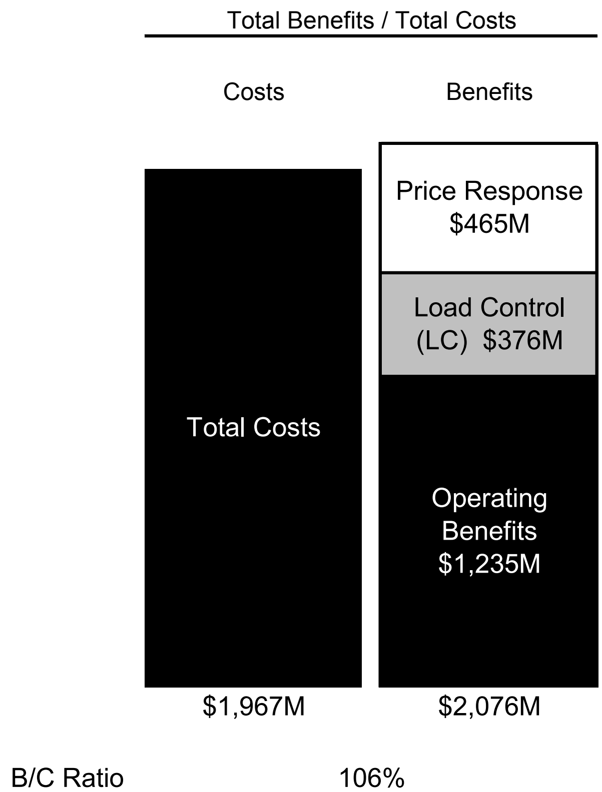
SCE's key objective for Edison SmartConnect™ is to provide customers with lasting value through a cost effective AMI investment that can empower them to manage their own energy costs and enable new services through smart technology. SCE also seeks to support federal and state energy policy objectives for AMI, to modernize its infrastructure with smart technologies and to continue to provide a catalyst for industry innovation to leverage this new generation of technology to maximize the value over its life for our customers.

A. New Functionality Increases the Net Benefits of the Investment by Approximately $1 Billion over the 2005 Business Case

Edison SmartConnect™ includes meter and telecommunication functionality that (i) provides advanced metering capability for interval electricity usage and voltage measurement; (ii) supports non proprietary open standard communication interface with load control technology within and around the premise (*e.g.,* programmable communicating thermostats and device switches); (iii) enables improved electric distribution management through outage detection at the customer premise; (iv) improves customer services through an integrated service switch (*e.g.*, remote service activation); (v) does not preclude the potential use of broadband over powerline by third parties (vii) supports ability to provide contract gas and water meter reads; and (viii) incorporates industry leading security capabilities for information and control messaging. These added functionalities and capabilities go far beyond meeting the Commission's six functionality requirements to provide a powerful tool to support federal and state energy policy objectives, and provide an enduring platform for continued innovation in meeting our customers' needs in the future.

Edison SmartConnect™'s added functionalities and capabilities also enable a cost effective business case. SCE projects that Edison SmartConnect™ will deliver $109 million in net benefits (present value revenue requirement or PVRR) to customers over the life of the project, as shown in Table II-1below.[5]

Table II-1
Edison SmartConnect™ Cost Benefit Analysis is Positive



SCE's cost benefit analysis includes an appropriate discount rate of ten percent (10%), based on the expected long term cost of capital. This discount rate is considerably higher than the discount rates used in the other AMI cases approved by the Commission.[6]

The cost-effective business case for Edison SmartConnect™ has been made possible by SCE's innovative and award-winning approach to AMI.[7] Driven by the state's vision to achieve advanced

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[5] The Edison SmartConnect business case is set forth in Exhibit SCE-3 of the supporting testimony.

[6] PG&E used a 7.60% discount rate; SDG&E used a 8.23% rate. If SCE were to use its 2007 authorized cost of capital as a discount rate instead of its incremental cost of capital (similar approach of SDG&E), SCE's net benefits of Edison SmartConnect would increase to $241 million.

[7] SCE's AMI deployment approach has gained national recognition, recently earning the Department of Energy's 2007 Smart Grid Implementation and Deployment Leadership Award as well as the Project Management Institute - Orange

(*Continued*)

metering and demand response for all investor-owned utility customers by 2007, and faced with the reality that a cost effective business case was not possible with then-available AMI technology, in 2005 SCE began an ambitious, multi-phased strategy to collaborate with the AMI vendor community to spur industry development of AMI solutions with the additional functionality and capabilities needed to reduce costs and add benefits of a full AMI deployment.[8] SCE's efforts, supported by the Commission through its approval of Phases I and II, have been successful in facilitating the development of the next-generation AMI solution that will provide lasting value for SCE's customers. SCE's expected meter and telecommunications selections are commercially available technologies that meet SCE's business and technical requirements. The selected meter data management system is one of the leading software applications currently in deployment for utilities with similar AMI requirements.

As a result of these efforts, SCE has added approximately $1 billion (PVRR) in net benefits to its business case since its previous AMI business case analyses in 2005.[9] This is a tremendous achievement that will ensure that AMI will achieve significant, long-term benefits for SCE's ratepayers. These benefits arose primarily from SCE's work to more fully explore the potential uses of the smart meter technology and engagement with the meter vendor community to enhance the capability, reliability, and useful life of the SmartConnect meter.

B. Empower Customers to Manage their Electricity Usage and Costs

Edison SmartConnect™ presents a unique opportunity to provide SCE's customers with new energy management alternatives that will enable them to reduce energy costs by using electricity more effectively and efficiently. By providing access to near real-time energy use and costs and enabling dynamic pricing options for residential and business customers under 200 kW with price signals closer

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Continued from the previous page
County Chapter's Project of the Year Award for 2006. Edison SmartConnect™'s Phase I was selected by The Utility Peer Network as the 2005/06 Best AMR Initiative in a North American Investor Owned Utility.

8 SCE's Phase I strategy and results and Phase II strategy are well documented in SCE's testimony in the Phase II proceeding (A.06-12-026).

9 From a negative $951 million Present Value Revenue Requirement (PVRR) in 2005 (*see* A.05-03-026) to a positive $109 million PVRR in 2007 for full AMI deployment.

to actual costs than tiered rate structures, Edison SmartConnect™ will be instrumental in managing peak consumption by providing an incentive for customers to shift some of their usage to off-peak hours. Peak consumption is a key factor in determining generating capacity requirements and customer costs, so managing peak load is essential to controlling the need to build expensive new power plants. Dynamic rates like Time of Use (TOU) and Critical Peak Pricing (CPP) provided peak load reduction in the Statewide Pricing Pilot compared to standard tariffs. Edison SmartConnect™ enables a range of dynamic rate design options that can improve customer acceptance and satisfaction.

Edison SmartConnect™ will inform customers of their costs and provide them options to manage their electric bills. SCE is proposing to provide both next day usage data and analysis tools to customers via the internet as well as near real time access to data directly from the meter as frequently as every 5 seconds through the HAN interface in the meter. This information will not only support adoption and response to dynamic rates and demand response program, but will also result in sustained changes in customer energy consumption. SCE expects a minimum of 1 percent energy conservation to result from the combination of customer access to usage information, dynamic prices and demand response programs. Customers will have access to near real time information, as available directly from the Edison SmartConnect™ meter through the HAN interface, which may result in considerably greater usage reduction according to industry findings. EPRI Solution found reductions ranging from 1 to 20 percent when customers were given real-time feedback,[10] identifying direct feedback as the key link between cause and effect for electric consumers. The review found that the more real-time the feedback is and the more it is offered with the provision of other influences (such as energy-saving information or dynamic prices), the better it influences behavior.

Edison SmartConnect™ will allow all residential and business customers to participate in reliability and economically dispatched base load control and demand response programs, providing the potential to reduce peak demand by as much as 1,000 megawatts -- the entire output of a large power

[10] *See* PUBLIC UTILITIES FORTNIGHTLY MARCH 2007 at p. 42, *citing Direct Energy Feedback Technology Assessment for Southern California Edison Company*, prepared by Lynn Fryer Stein and Nadav Enbar, EPRI Solutions, March 2006 (noting that there is a risk of self-selection bias toward those more interested in conservation.) *See also* Ontario Energy Board Smart Price Pilot, Final Report July 2007, p. 7, estimating energy conservation to be at six percent.

plant -- with the related customer cost savings and environmental benefits. Through demand response programs enabled by Edison SmartConnect™, customers will be able to reduce their on-peak energy usage and provide SCE and the state with a valuable, dispatchable demand side resource. This long-held goal of the Commission will be realized with Edison SmartConnect™. Further, Edison SmartConnect™ provides the means to accurately measure each customer's response, thereby assuring that customers who do take action during demand response events to curtail peak load can be appropriately rewarded. More precise load impact measurement will greatly facilitate the use of demand response as a reliable alternative to generation resources to meet SCE customers' energy needs.

Edison SmartConnect™ also presents new opportunities to use demand response in ways that were not previously possible. The current proposal by the California Energy Commission (CEC) to require programmable communicating thermostats (PCT) as part of the Title 24 (T24) building code in 2008 provides a unique opportunity for Edison SmartConnect™ to provide an open communication link to the PCT to enable load control for reliability and economic dispatch purposes. Customers with T24 PCTs and SCE-implemented PCT programs will have the potential to realize significant peak load reductions.

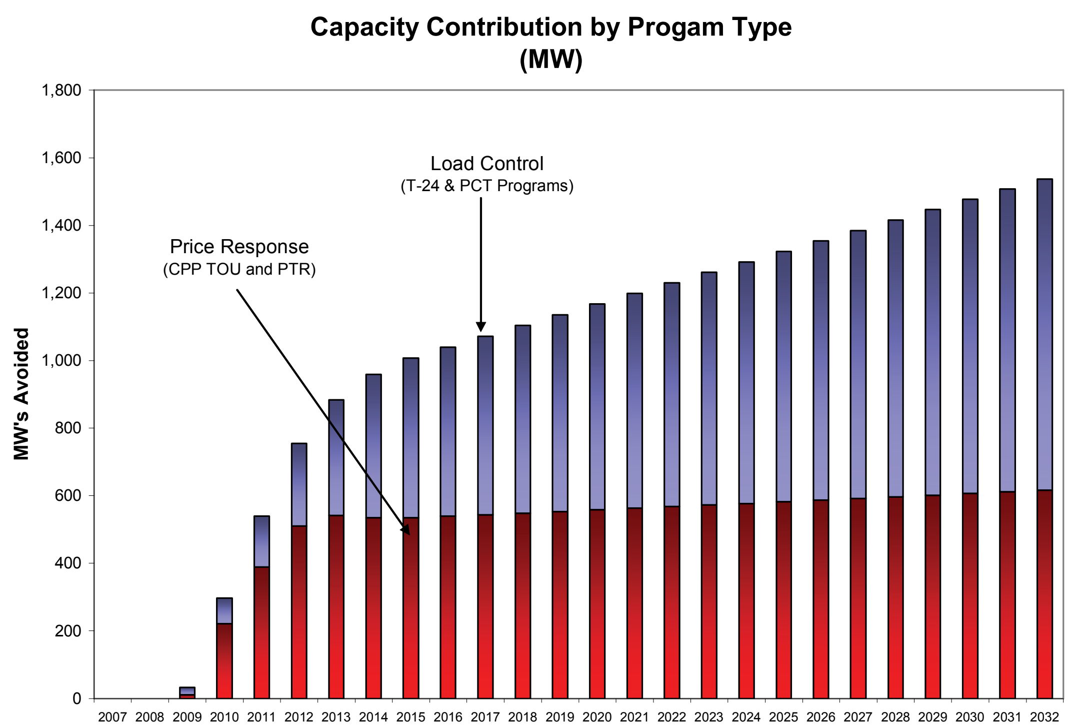
Additionally, with Edison SmartConnect™, SCE expects to increase the benefits from its existing air conditioning cycling program (ACCP). Currently, SCE's ACCP is used for grid reliability and not as a resource to reduce energy procurement costs. With Edison SmartConnect™, ACCP can be dispatched on an economic basis as well as for grid emergencies, making more effective use of that load control program. The estimation of load control impacts would also improve with Edison SmartConnect™ because hourly load reductions could be analyzed in detail.

Edison SmartConnect™ also enables the use of load control devices for automated load reduction on critical peak days. Customers on a CPP rate or the Peak Time Rebate program could use automated load control to manage their critical peak energy usage and save money, thereby reducing the need for additional incentive payments through load control programs. With Edison SmartConnect™, SCE can offer load control programs as well as dynamic rates that can be supplemented with automated control of the PCT as an enabling load reduction technology on critical peak days. The Statewide

Pricing Pilot results indicated the combination of CPP and automated load control resulted in greater peak reduction than the sum of CPP or load control achieved alone. This type of synergistic effect is precisely what Edison SmartConnect™ seeks to achieve.

Figure II-1 below shows the forecasted peak MW reductions per year expected to result from Edison SmartConnect™.

Figure II-1
Estimated Peak Demand Reduction for Price Response and Load Control Programs



C. <u>Create Lasting Customer Value Through Cost-Effective Advanced Metering Technology Solutions</u>

Promising new technologies enabled by Edison SmartConnect™ offer the potential to significantly broaden the field of stakeholders in the energy management arena of the future. In anticipation of future changes in technology and changes in regulatory policy objectives, SCE has designed flexibility into its Edison SmartConnect™ system to accommodate the likelihood of future rate options (including plug-in hybrids), contract automated gas and water meter reading, future Title 24 code changes, in-home energy information displays, smart grid management, and distributed resources.

Edison SmartConnect™ will enable the use of "communicating" household devices, such as thermostats, lighting, electric dryers, other major appliances and pool pumps, which can communicate with the new meters through a nationally recognized non-proprietary open Home Area Network (HAN) interface to automatically adjust usage, at customers' direction, when power costs rise. The HAN interface will enable (i) customer access to energy usage information directly from the meter; (ii) a channel for pricing signals or notification of grid events; (iii) communication links to other energy meters for solar, plug-in hybrids, gas and water meters; and (iv) a communication link to T24 and compliant smart thermostats and other potential controllable devices that a customer may elect. Customer access to energy information is one of the core tenants of AMI. SCE believes this HAN interface and some form of in-home energy display could provide the nearly one million SCE customers who do not have internet access, an alternate means to access their usage, which will enable them to make smart choices. Customers would control the HAN as it evolves, with the meter to HAN interface based on nationally recognized non-proprietary open standards that provide effective security.

This type of HAN interface capability, first proposed by SCE in early 2005, has been incorporated into the leading vendors' products based on market demand. For example, the Texas Public Utilities Commission smart meter rules[11] recently adopted the HAN interface in smart meters and this capability is being deployed in Texas, Canada, Australia, Europe and Asia and as part of SCE's Phase II field test.

Edison SmartConnect™ will also make doing business with SCE easier by allowing for convenient, remote service activation, access to near real-time energy and service information, and billing and payment options, among other new customer services. In addition, third party vendors of

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[11] The Texas Public Utilities Commission's smart meter rules adopted in May 2007 includes a requirement of "capability to communicate with devices inside the premises, including, but not limited to, usage monitoring devices, load control devices, and prepayment systems through a home area network (HAN), based on open standards and protocols that comply with nationally recognized non-proprietary standards such as ZigBee, Home-Plug, or the equivalent." *See* §25.130.g.1 of such rules.

smart appliances, home automation, demand response and energy efficiency services and products will continue to emerge to assist customers to take advantage of the benefits of Edison SmartConnect™, providing customers information on energy savings options without adding to SCE's cost of service.

D. Support SCE's Strategy of Modernizing its Infrastructure with Smart Technologies Toward an Intelligent Grid

Edison SmartConnect™ will modernize SCE's infrastructure with smart technologies toward an intelligent grid consistent with federal energy policy to reduce peak demand, enable faster outage response, and improve customer service and grid management. Through on-demand energy information, dynamic rates and demand response programs, Edison SmartConnect™ will help customers reduce peak demand, which is essential to controlling the need to build expensive new power plants. Edison SmartConnect™ will also improve basic utility services. By allowing dispatchers to know immediately when and where outages occur, Edison SmartConnect™ will enable utility crews to respond to outages more quickly. Through the remote activation switch, SCE's one million annual requests for turn-on of electric service by residential customers will have the convenience of fast, remote service activation. SCE expects to leverage the outage, power quality and energy usage data from the Edison SmartConnect™ system to improve grid management and power procurement and settlement.

E. Continue as a Catalyst For Industry Innovation to Maximize the Value of the Edison SmartConnect™ Technology

SCE anticipates that Edison SmartConnect™ will continue to be a catalyst for industry innovation to leverage this new generation of technology to enhance our customers' experience and enable smart grid capabilities.

Through a deliberate open innovation process in Phases I and II, SCE involved manufacturers of promising AMI technologies in ongoing dialogue on product enhancements and SCE's desired system functionality. SCE shared its technical requirements and concept definition with communications vendors, meter vendors and utility industry groups. This process helped to establish standards for a new generation of AMI-related meters and communication systems that can better address electric utility needs. These discussions, and the independent decisions that resulted from them, acted as a catalyst to spur successful industry-wide product development efforts.

As SCE deploys Edison SmartConnect™ in Phase III, it will continue to focus on delivering benefits beyond those that have been identified to date and included in SCE's cost benefit analysis. From a technical perspective, continued effort is required to develop system security requirements and to have such requirements adopted by product vendors. In addition, common information models are needed to ensure interoperability between devices on a smart grid and customer devices that can leverage the Edison SmartConnect™ system. This work will dovetail with the continuing efforts to design and build a smart grid for the 21st century that accommodates the expected increase in customer controlled distributed generation and load resources.

SCE also expects that socio-economic trends and consumer buying behaviors over the Deployment Period will change significantly. Specifically, the trends suggest that as many as one million immigrants moving into Southern California by 2012 and that the retirement segment of the population will grow exponentially as baby boomers are now reaching traditional retirement age at the rate of one person every 8 seconds. These types of customer changes will mean that SCE will need to adapt to serve our customers and achieve state and federal policy objectives. SCE intends to build on the success of Phase I and II, which was recognized by the Department of Energy through the Smart Grid Implementation and Deployment Leadership Award at GridWeek 2007. SCE will continue to lead the way in defining the role of advanced metering in a smart grid and developing its potential to unlock energy savings through different and improved relationships with customers.

III.

EDISON SMARTCONNECT™ SATISIFIES STATE ENERGY POLICY OBJECTIVES AND MEETS MINIMUM FUNCTIONALITY REQUIREMENTS

A. Support the State's Energy Action Plan and Past Decisions

With timely approval, Edison SmartConnect™ will support the Commission's and the state's energy policy to provide all SCE customers with dynamic pricing options and demand response tools without delay. The Commission's directive on expeditious implementation of dynamic pricing for all customers was first articulated in Decision (D.)03-06-032: "All California electric consumers should have the ability to increase the value derived from their electricity expenditures by choosing to adjust usage in response to price signals, by no later than 2007." In D.03-06-032, the Commission established the objective of achieving through demand response a target of five percent reduction in system peak demand by 2007.[12] In early 2007, Commissioner Chong, along with Commissioner Rosenfeld of the California Energy Commission, reiterated the Commission's vision for dynamic pricing and customer choice, and made it clear that AMI was central to that vision.[13] Edison SmartConnect™ will achieve this vision, and provide SCE the ability to strive to meet the Commission's targets for demand response starting in 2009.

The Energy Action Plan (EAP), adopted in 2003 by the Commission, the California Energy Commission, and the California Power Authority, also seeks the expedient implementation of dynamic pricing. In particular, the first action item under the section entitled *Optimize Energy Conservation and Resource Efficiency* establishes an objective to "[i]mplement a voluntary dynamic pricing system to reduce peak demand by as much as 1,500 to 2,000 megawatts by 2007." The Commission found that implicit in the EAP's objective is the need for the utilities to install technologies to enable consumers to voluntarily respond to such a dynamic pricing system.[14] The Commission acknowledged that being

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[12] *See* D.03-06-032 at Attachment A.

[13] *See* the January 25, 2007 presentation of Commissioner Chong and Commissioner Rosenfeld to the CAISO Market Issue Forum entitled *Demand Response: Policies, Challenges, and Future Possibilities.*

[14] *See* D.05-09-044 *mimeo* at p. 12 (emphasis added).

behind in the timeframe established in the EAP means that the Commission should place a stronger emphasis on authorizing the utilities to move forward as soon as possible.[15] To that end, SCE has accelerated its Edison SmartConnect™ deployment schedule by one full year, to enable initial meter installations to begin in 2009.

The EAP II, adopted in 2005 by the Commission and the California Energy Commission (CEC), contains even more explicit references to AMI deployment. Section 2, entitled *Demand Response* provides,

> "California is in the process of transforming its electric utility distribution network from a system using 1960s era technology to an intelligent, integrated network enabled by modern information and control system technologies. This transformation can decrease the costs of operating and maintaining the electrical system, while also providing customers with accurate information on energy use, time of use, and cost. With the implementation of well-designed dynamic pricing tariffs and demand response programs for all customer classes, California can lower consumer costs and increase electricity system reliability."

The EAP II states that the *first key action* for demand response is to "issue decisions on the proposals for statewide installation of advanced metering infrastructure for small commercial and residential TOU customers by mid-2006 and expedite adoption of concomitant tariffs for any approved meter deployment." With prompt approval, SCE will be able to bring the benefits of Edison SmartConnect™ to SCE's customers and to the state sooner.

B. Meet the Commission's Minimum Functionality Requirements

In D.07-07-042 (the Phase II Decision), the Commission found that SCE's proposed AMI system design will satisfy the Commission's minimum functionality requirements.[16] Those minimum functionality requirements were identified in the February 19, 2004 Joint Assigned Commissioner and Administrative Law Judges Ruling Providing Guidance for the Advanced Metering Infrastructure Business Case Analysis, and are described briefly below.

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[15] *See id.*

[16] *See* D.07-07-042 at Finding of Fact 1.

1. Edison SmartConnect™ System Will Support Implementation of Time-of-use, Critical Peak Pricing and Real-Time Pricing Tariffs to All Customers

Like the other California investor owned utilities, SCE has already installed advanced meters for its customers with demands over 200 kW (approximately 13,000 total). These Real Time Energy Meters (RTEM) are fully capable of supporting Time-Of-Use, Critical-Peak-Pricing and real-time pricing tariffs. Edison SmartConnect™ will expand this capability to include all residential and small commercial customers below 200 kW.

2. Edison SmartConnect™ Will Collect Hourly Usage Data to Support Customer Understanding of Usage Patterns

Edison SmartConnect™ capability requirements include the ability to collect and store hourly usage data for all residential and 15 minute data for commercial customers under 200 kW, regardless of their current rate structure. Edison SmartConnect™ data can be used to support customer understanding of hourly (and 15 minute) usage patterns and how this relates to a customer's energy costs when considering shifting to or from alternative rates.

3. Edison SmartConnect™ Will Provide 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

Edison SmartConnect™ is designed to provide direct, next-day customer access to their interval usage data and up to 13 months of rolling historical usage data over the internet. The Home Area Network (HAN) interface incorporated into Edison SmartConnect™ will also allow customers to have direct access to near real time (to 5 second intervals) meter data via the customer's energy information device (*e.g.*, display device or simple software on personal computer with HAN communication link.)

This same HAN interface will also be in commercial meters to allow C&I customers direct access to the meter data to facilitate access for energy management and/or building control systems. Historically, the cost of additional equipment to access a commercial meter has been an impediment for the application of energy management systems (EMS) for small to medium C&I

customers. With Edison SmartConnect™, customers will only need to complete a relatively simple registration process to link their EMS to access their meter data.[17]

4. Edison SmartConnect™ Will Be Compatible with Customer Education and Energy Management Applications, Customized Billing and Complaint Resolution Programs that Utilize AMI Data

Edison SmartConnect™ is designed to support the delivery of customer energy information through multiple channels including the Internet as well as customer premise devices (*e.g.*, displays and building management systems). Edison SmartConnect™ system design has the flexibility to enable potential future communication channels such as customer cell phones and other mobile devices. Edison SmartConnect™ will support new services such as tailored billing and payment options that could include a pre-payment option. Finally, Edison SmartConnect™ will allow on-demand reads by call center representatives as well as information regarding outages, thus improving customer service and inquiry and/or complaint resolution.

5. Edison SmartConnect™ System Will Be Compatible with Utility System Applications that Promote and Enhance System Operating Efficiency

The compatibility of Edison SmartConnect™ with other existing and future utility systems was a primary objective of the Use Case Process undertaken in Phase I.[18] SCE expects to leverage the outage, power quality and energy usage data from the AMI system to improve service, grid management and power procurement and settlement. Edison SmartConnect™ will modernize SCE's infrastructure with smart technologies reduce peak demand, enable faster outage response, and improve customer service and grid management.

Through on-demand energy information, dynamic rates and demand response programs, Edison SmartConnect™ will help customers reduce peak demand, thereby reducing the need to build expensive new power plants. Edison SmartConnect™ will also improve basic utility services. By

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[17] For example, McDonalds recently announced that it is installing EMS in its restaurants. This system would be able to access near real-time meter data through the meter's HAN interface.

[18] *See* SCE's August 2006 *AMI Conceptual Feasibility Report*.

allowing dispatchers to know immediately when and where outages occur, Edison SmartConnect™ will enable utility crews to respond to outages more quickly. Through the activation switch, the approximately one million residential accounts that are new or relocate each year will have the convenience of fast, remote service activation.

6. Edison SmartConnect™ System Will Be Capable of Interfacing with Load Control Communication Technology

One of the unique accomplishments of SCE's Phase I concept definition and engineering design process was the ability to define and specify the functional requirements for a HAN interface capability integrated into the AMI meter. This provides the capacity for two-way communications with customer-owned or third-party provided energy management devices; specifically, the CEC's proposed Title 24 PCT. This capability is a critical part of SCE's Metering and Telecommunications product selection.

SCE is planning to implement new load control management software as part of Edison SmartConnect™ that would allow use of the load control system for both grid reliability and economic dispatch. This software application will be integrated with the customer care systems and meter/telecom network to optimize the value of the programs.

C. Satisfy Design Objectives of Phase I Settlement

In Phase I, several other design objectives were identified that SCE will achieve with Edison SmartConnect™, including incorporating interfaces for gas and water utility automated meter reading into the system, as well as incorporating security methods to protect customer privacy.[19]

Interfaces for gas and water utility automated meter reading. SCE has narrowed the choice for AMI technology to vendor products that can support automated reads for gas and water meters. This can be accomplished either through communication with the proprietary local area network or the non-proprietary open standard HAN interface. SCE continues to engage representatives from various utilities with whom SCE currently has meter reading contracts and Southern California Gas Company to

[19] *See* Decision 05-12-001, at Settlement Agreement, Attachment A.

explore potential use of Edison SmartConnect™ for gas and water meter reads and other functionality.[20] While it will be technically possible for SCE to support gas and water reads, it is necessary for the gas and water utilities to retrofit their meters to be able to communicate with the Edison SmartConnect™ system. SCE expects to begin more detailed discussions with gas and water utilities after final vendor selection at the end of 2007 and is contemplating including a pilot of this capability in 2008.

Security. SCE takes security very seriously and has spent a considerable amount of time on assessing the security needs of its AMI system, as evidenced in SCE's conceptual architecture and requirements incorporated in the RFPs as well as evaluating vendor products, identifying security gaps in the technology, and working with vendors to enhance their products to meet SCE's requirements. Additionally, SCE's Technology Advisory Board is comprised of a "blue ribbon" panel of industry experts, most of whom have significant expertise in making information and telecommunications systems like AMI secure. SCE has also engaged security consultants with significant experience in Department of Defense applications and sophisticated electric grid applications. As a result, SCE has proposed one of the most comprehensive and stringent set of security requirements for an AMI system to date and is engaged with utilities and AMI technology and cryptographic vendors through SecurityAMI, T24 PCT specification development and other venues. The objective is to ensure the integrity and confidentiality of the information exchanged through the SmartConnect system and that the system can respond to inadvertent and malicious risks.

[20] SCE engaged these utilities in Use Case Workshops in 2006 that resulted in a fully developed Use Case for Contract Meter Reading, and requirements have been incorporated into SCE's conceptual architecture for meters, telecommunications and back office systems and the RFPs.

IV.

EDISON SMARTCONNECT™ DEPLOYMENT IS COST EFFECTIVE

A. The Cost Benefit Analysis is Positive

Edison SmartConnect™ is expected to deliver $109 million in net benefits (present value revenue requirement or PVRR) to customers over the life of the project. Operational savings are forecast to cover approximately 63 percent of the related costs. Participation by residential and <200kW business customers in dynamic pricing and demand response programs is expected to provide sufficient additional benefits to justify the Edison SmartConnect™ project. The cost-benefit analysis is summarized in Table IV-2 below.

Table IV-2
Cost-Benefit Analysis Results
(Nominal 2007 Present Value of Revenue Requirement, in Millions)

	Nominal	PVRR
Benefits		
Operational Benefits		
During Deployment Years	278.2	
During Post-Deployment Years	4,299.0	
Demand Response Benefits		
During Deployment Years	216.2	
During Post-Deployment Years	2,792.6	
Subtotal Operational Benefits	4,577.2	
Subtotal Demand Response Benefits	3,008.8	
Total Benefits	**7,586.0**	**2,076.00**
Costs		
Phase II Costs (D.07-07-042)	45.2	
Deployment Costs		
Acquisition of Meters and Communication Network Equipment	838.0	
Installation of Meters and Communication Network Equipment	296.6	
Implementation and Operation of New Back Office Systems	191.2	
Customer Tariffs, Programs and Services	112.1	
Customer Service Operations	84.1	
Overall Program Management	45.6	
Contingency	147.3	
Post-Deployment Costs		
Billing	127.1	
Call Center	93.5	
Meter Services	399.1	
Back Offices Systems	344.4	
Customer Tariffs, Programs and Services	245.0	
Subtotal Pre-Deployment Costs	45.2	
Subtotal Deployment Costs	1,714.9	
Subtotal Post-Deployment Costs	1,209.0	
Total Costs	**2,969.1**	**1,967.00**
Total Benefits Less Total Costs	**4,616.9**	**109.0**

The full cost-benefit analysis is provided in Volume 3 (Exhibit SCE-3). It incorporates SCE's expected technology selections and current vendor pricing for full deployment of Edison SmartConnect™ as well as contingency costs reflecting the risk factors still accompanying several key cost areas, which are discussed in detail in Volume 2 (Exhibit SCE-2).

SCE's analysis includes an appropriate discount rate of ten percent (10 percent), based on the expected long term cost of capital. This discount rate is considerably higher than the discount rates used in the other AMI cases approved by the Commission.[21] The cost benefit analysis for deploying Edison SmartConnect™ represents about a $1 billion improvement in net benefits from SCE's previous analysis filed in March 2005.[22]

SCE's efforts over the past two years have focused on maximizing the value of advanced metering for our customers and utility operations. Beginning in Summer 2005, SCE has continually refined its assessment of the cost-effectiveness of AMI. In Phases I and II, through its extensive Request for Proposals (RFP) process and component testing of the first production models of metering and communication products, SCE has gained new insights into the functional capabilities, reliabilities and costs of commercial advanced metering products and deployment. SCE was able to refine its deployment plan and improve upon previous financial analyses with more current market information. Through its customer and market research, SCE was able to refine the demand response offerings that can help advance the state's demand response goals.

SCE's efforts, supported by the Commission through its approval of Phases I and II, have been successful in facilitating the development of a cost-effective advanced metering solution using next-generation technology that will provide lasting value for SCE's customers.

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[21] In comparison, PG&E used a 7.60% discount rate in its AMI case, and SDG&E used a 8.23% rate. If SCE were to use its 2007 authorized cost of capital as a discount rate instead of its incremental cost of capital (similar approach of SDG&E), SCE's net benefits of Edison SmartConnect would increase to $241 million.

[22] *See* A.05-03-026.

B. The Benefits of Edison SmartConnect™ are Real and Long-Term

Through its AMI System Design and Use Case Process, SCE will integrate Edison SmartConnect™ into its operating systems to ensure that the expected benefits accrue in the areas of customer service, billing, outage management, and operations and maintenance. The Use Cases identified potential new uses for Edison SmartConnect™ that were integrated into the technical specifications for the metering and telecommunication systems, thereby enabling SCE to maximize the benefits of Edison SmartConnect™.

The benefits of Edison SmartConnect™ include far more than the most obvious operational benefits resulting from automation of meter reading and field service activities. As discussed in Volume 3 (Exhibit SCE-3), SCE has identified three types of benefits: operational benefits, demand response benefits, and societal benefits. Operational benefits are well within the reach of SCE. Demand response benefits are also within reach, but will require Commission authorization of dynamic tariffs and demand response programs,[23] and action by customers to reduce their peak load through participation in such dynamic tariffs and demand response programs.

Societal benefits are real but they reflect improvements in services or conveniences with value to customers or to society in general that are not reflected in utility cash flow. These benefits include improvements in customer experience, reductions in energy theft, greenhouse gas reductions, and other societal benefits. Societal benefits are not included in SCE's cost benefit analysis because the value of such benefits does not flow through to SCE's revenue requirement. However, such benefits are often considered important by the Commission.[24] SCE has prepared a qualitative discussion of the societal benefits and other non-quantifiable future benefits such as the use of the load limiting capability of the service switch and the conservation effect from the HAN near real time data access. The value of the societal benefits should serve to further justify the Edison SmartConnect™ project.

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[23] SCE intends to propose modified TOU and CPP rates as well as a Peak Time Rebate program in Phase II of its 2009 General Rate Case.

[24] For example, the Commission in D.05-06-016 approved the AG-ICE program of incentives for agricultural customers who convert engines used for agricultural pumping from diesel fuel to electricity, in an effort to achieve a significant improvement in the air quality of the San Joaquin Valley.

V.

SUMMARY OF REQUESTS

Phase III of SCE's AMI project should be implemented without delay to begin achieving the benefits of Edison SmartConnect™. Accordingly, SCE seeks authority to:

(i) proceed with full deployment of Edison SmartConnect™ to all residential and business customers under 200 kW (approximately 5.3 million meters) in SCE's service territory over a five-year period beginning in 2008 at an estimated cost of $1.7 billion;

(ii) implement a voluntary Programmable Communicating Thermostat (PCT) load control program throughout the five-year deployment period and conduct marketing, outreach and education on the dynamic rates and demand response program offerings for customers receiving the Edison SmartConnect™ meters;[25]

(ix) establish the Edison SmartConnect™ Balancing Account (SmartConnect BA) to provide for the recovery of Phase III recorded revenue requirements, which include recorded incremental costs and recognition of forecast operational O&M benefits, effective upon a Commission decision on this application;

(x) reduce its Authorized Distribution Base Revenue Requirement (ADBRR), on an annual basis, in order to recognize the Phase III capital benefits related to specific projects as set forth, and as adopted, in this proceeding, through the effective date of SCE's 2012 GRC Decision;

(xi) transfer the balance in the SmartConnect BA, each month, to the Base Revenue Requirement Balancing Account (BRRBA) to enable recovery, through distribution rate levels, of the actual Edison SmartConnect™-related revenue requirements for Phase III activities beginning on the effective date of a decision in this proceeding and continuing through the effective date of SCE's 2012 GRC Decision;

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[25] SCE intends to re-activate the CPP rate(s) used for the SPP via an advice filing, and offer existing TOU rates and re-activated CPP rates pending approval of a modified TOU and CPP rates in Phase II of SCE's 2009 GRC. SCE also plans to seek approval of a new Peak Time Rebate program in Phase II of SCE's 2009 GRC.

(xii) transfer from the AMIMA to the BRRBA the 2007 and 2008 recorded revenue requirements associated with costs that will be incurred in 2007 associated with Phase II activities that did not receive authorization for recovery in D.07-07-042 and 2007 and 2008 revenue requirements associated with the $14.1 million of capital expenditures (plus $0.4 million of AFUDC) approved in D.07-07-042 but not allowed rate base treatment;

(xiii) recover, through distribution rate levels, of SCE's forecast Edison SmartConnect™ revenue requirements for Phase III activities effective upon a Commission decision on this application and continuing through the effective date of SCE's 2012 GRC Decision; and

(xiv) limit reasonableness review of the SmartConnect BA to ensure all recorded costs are associated with Phase III activities as defined and adopted by the Commission in this proceeding.

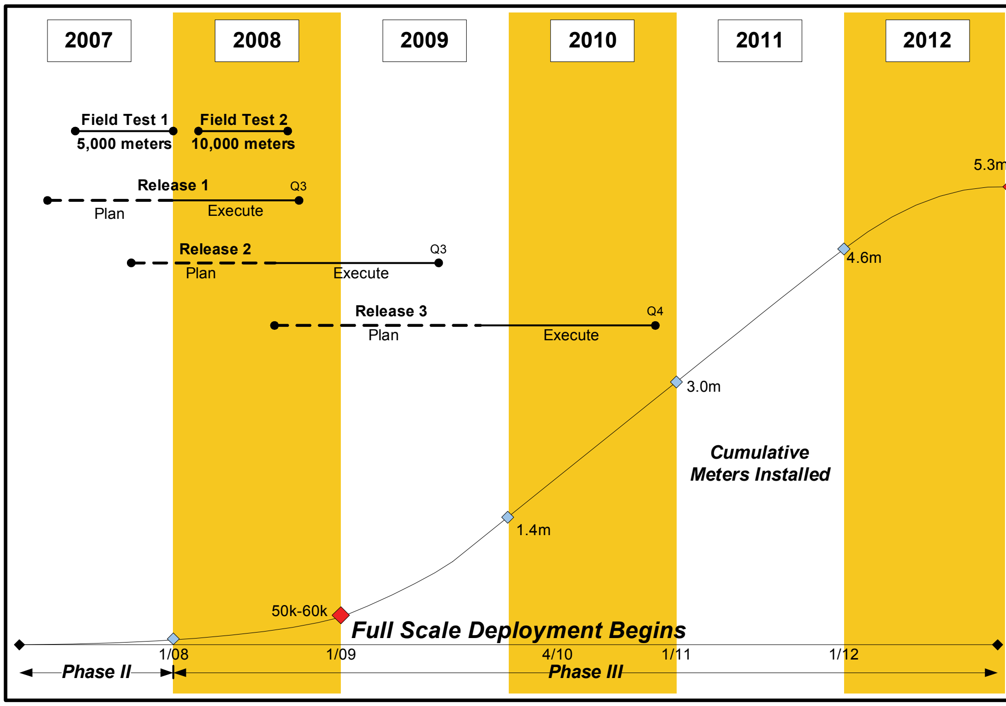
SCE requests Commission approval of these requests by June of 2008 to remain on schedule for meter installation to begin in January 2009.

A. SCE's Deployment Plan for Edison SmartConnect™ Should be Approved

As part of the detailed planning for deployment, SCE identified three distinct releases for all the systems development and integration work associated with Edison SmartConnect™. Phase III will begin with the execution of the first release, which involves the final development and testing of the Meter Data Management System and telecommunications network management system and integration with the customer billing system. A second field test of up to 10,000 additional meters will validate the installation processes and the expected revised version of the meter/telecom products based on Phase II engineering and development.

Phase III deployment will include two additional releases of the AMI system, each being slated to achieve a higher and more complex level of functionality than the previous one. These progressively increasing functionalities will be timed as illustrated in Figure V-2 below. This figure also shows the ramping-up of meter installations in relation to each respective Release and over time through June 2012 for the full Phase III deployment period.

Figure V-2
Timeline for AMI Phases II and III



The activities and estimated costs and benefits for Phase III are described in detail in Volume 2 (Exhibit SCE-2). The costs and benefits of the Edison SmartConnect™ over the entire life of the project are discussed in Volume 3.

B. SCE Should be Authorized to Offer Voluntary Load Control Programs as SmartConnect Meters are Installed

SCE requests authority to implement a voluntary PCT load control program as the Edison SmartConnect™ meters are installed during the deployment period. SCE plans to seek rate design authorization for other demand response programs (*e.g.*, Peak Time Rebate) and modified TOU and CPP rates in its 2009 GRC Phase II application.

Load control programs provide significant peak load reductions and power procurement benefits. An essential part of SCE's approach to load control is a PCT compatible with the anticipated Title 24 building code standard under development by the California Energy Commission (CEC) for implementation in 2009. In Phase III, SCE will continue to work with the CEC and other utilities on developing the PCT technology that is compatible with Title 24 and AMI. SCE envisions leveraging the Title 24 compliant PCTs purchased and installed by customers pursuant to Building Code requirements and also offering rebates for purchasing and installing Title 24 compliant PCTs to customers with existing air conditioning units. SCE will continue to work with thermostat vendors and other parties to accelerate the testing of affordable PCTs.

Dynamic pricing options like TOU, CPP and PTR will provide significant peak load reductions. SCE has existing opt-in TOU and CPP rates for residential and business customers, which are available to customers as their advanced meters are deployed in 2009. SCE will seek to modify these existing rates in Phase II of its 2009 GRC. Pending a decision approving the modified rates in Phase II of the 2009 GRC (expected in October 2009), SCE seeks to re-activate the Critical Peak Pricing rate(s) used for the SPP, and plans to offer its existing, voluntary TOU rates, to residential and business customers under 200 kW as the advanced meters are rolled out in 2009. SCE also plans to request authority in Phase II of the 2009 GRC to implement a Peak Time Rebate (pay-for-performance) program for residential and business customers under 200 kW during the deployment period.

SCE provides a detailed discussion of the dynamic rates and demand response programs planned for the deployment period in Volume 4 (Exhibit SCE-4).

C. SCE Should be Authorized to Recover Costs Incurred during the Deployment Period through a Balancing Account

SCE requests approval to recover the revenue requirement associated with the costs of Phase III activities described in Exhibit SCE-2. These costs are estimated at approximately $384.2 million in O&M and $ 1,330.7 million in capital expenditures over the 2008 through 2012 deployment period.[26]

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[26] These amounts include $8 million of capital expenditures and O&M expense that will be incurred in 2007 associated with Phase II activities that did not receive authorization for recovery in the Commission's Phase II Decision No. 07-07-042. In addition, SCE will include in the Edison SmartConnect™ revenue requirement $14.1 million of capital expenditures (plus $0.4 million of AFUDC) approved in D.07-07-042, but not allowed rate base treatment.

SCE proposes to establish an Edison SmartConnect™ balancing account mechanism to provide for recovery of the deployment period revenue requirement, which will include the recognition of operational benefits in the form of offsets to the Phase III costs.[27] This forecast revenue requirement will be recovered in distribution rates from 2009 through 2012 based on the estimated O&M expenses, depreciation, taxes, and authorized return on rate base amounts as derived from the estimated capital expenditures and the estimated operational benefits as set forth in this application. Beginning in 2009, the forecast Phase III revenue requirement for 2009 and any undercollection in the Base Revenue Requirement Balancing Account (BRRBA) arising from deployment activities in 2007 and 2008 will be reflected in SCE's total distribution rates. However, the proposed operation of the Edison SmartConnect™ balancing account mechanism (*i.e.*, the actual revenue requirement recorded in the Edison SmartConnect™ balancing account will be transferred to the BRRBA each month) will ensure that no more and no less than the reasonable revenue requirement associated with Phase III activities is ultimately collected from customers.

Assuming the Commission approves the scope of activities proposed by SCE and the forecast Phase III costs in this application, SCE's incurred costs that are consistent with the scope and within the cost levels adopted by the Commission should not be subject to an after-the-fact reasonableness review. If actual costs exceed the forecast, or if the scope of activities differs from what the Commission has approved, then SCE would file an application, or other appropriate procedural vehicle, to request approval of the activities and recovery of the additional costs subject to a traditional after-the-fact reasonableness review.

SCE's revenue requirement and cost recovery mechanism for Phase III is set out in Volume 5 (Exhibit SCE-5) of the supporting testimony of this Application.

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[27] SCE proposes to flow back all Phase III capital-related benefits outside of the SmartConnect™ balancing account mechanism. *See* Exhibit SCE-5.

VI.

CONCLUSION

Phase III should be approved by no later than June 2008 so that SCE can begin delivering the benefits of Edison SmartConnect™ to its customers and the state.

Appendix A

Witness Qualifications

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF LYNDA L. ZIEGLER

Q. Please state your name and business address for the record.

A. My name is Lynda L. Ziegler, and my business address is 8631 Rush Street, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. As Senior Vice President, Customer Service Business Unit, I am responsible for Edison's customer experience, industry-leading demand-side management programs and advanced metering, as well as customer-facing operations, phone center activities, field services, account management, and local public affairs.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Marketing from California State University, Long Beach, in 1982, and an MBA from California State University, Fullerton, in 1988. In 1981, I joined the Southern California Edison Company. I have held a number of different positions, several in the energy efficiency area. I have been a program planner, a field supervisor, major account executive, Manager of Energy Efficiency Programs, Director and later Vice President of Customer Programs and Services. Outside of the energy efficiency arena, I have served as a Customer Service Manager, Service Planner, and Credit Manager.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of this Exhibit SCE-1, as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF PAUL J. DE MARTINI

Q. Please state your name and business address for the record.

A. My name is Paul J. De Martini, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the Edison SmartConnect™ Program Director. I am responsible for managing all aspects of the AMI program feasibility, system design, development and deployment efforts.

Q. Briefly describe your educational and professional background.

A. I hold a Master of Business Administration (M.B.A) degree from the University of Southern California and a Bachelor of Science (B.S.) degree in Applied Economics from the University of San Francisco. I also completed Certificates in Project Management from the University of California, Berkeley and Technology Management from the California Institute of Technology. I have been at Southern California Edison for about five years during which I was the IT Project Manager on AMI beginning in 2004, prior to assuming the overall program management responsibility in 2005. Relevant positions prior to joining Southern California Edison included Vice President of the Energy Strategy practice at ICF International in 2000-2002 with a focus on demand response, advanced metering and distributed generation technologies. I began my career at PG&E Corporation in both regulated and unregulated businesses for nearly twenty years. I held positions at the utility with increasing responsibility involving electric systems operations, T&D project management, and wholesale power procurement and ultimately at the unregulated subsidiary PG&E Energy Services as Vice President, Integrated Services.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of this Exhibit SCE-1 as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?
A. Yes, it was.
Q. Insofar as this material is factual in nature, do you believe it to be correct?
A. Yes, I do.
Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A. Yes, it does.
Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.

Application No.:	07-07-
Exhibit No.:	SCE-2
Witnesses:	L. Cagnolatti P. Campbell P. De Martini J. Gregory E. Helm C. Hu S. Kiner L. Oliva

SOUTHERN CALIFORNIA
EDISON
An *EDISON INTERNATIONAL* Company

(U 338-E)

EDISON SMARTCONNECT™ DEPLOYMENT FUNDING AND COST RECOVERY

Volume 2: Deployment Plan

Before the

Public Utilities Commission of the State of California

Rosemead, California

July 31, 2007

LAW #1386192

EDISON SMARTCONNECT™ DEPLOYMENT FUNDING AND COST RECOVERY

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I.

INTRODUCTION

The purpose of this exhibit is to present a detailed description of the deployment plan for Edison SmartConnect™, Southern California Edison Company's (SCE's) proposed advanced metering infrastructure (AMI) solution and its related customer tariffs, programs and services. Through its deployment plan, SCE will accomplish the installation of Edison SmartConnect™ meters to all residential and small commercial customers below 200 kW (approximately 5.3 million meters) over a five-year period from 2008 through 2012 (the "Deployment Period"). SCE's proposed deployment plan goes beyond the technical and logistical aspects of installing a major new metering infrastructure. SCE's AMI system design and deployment plan entails a comprehensive effort to meet the six functional requirements of the Commission[1] and the additional functionality identified in the Phase I Settlement Agreement[2] through a new generation of metering, communications and data processing systems to enable the customer to make informed, intelligent decisions regarding their energy choices. In SCE's Phase II decision on pre-deployment, the Commission found that SCE has satisfied the Commission's functional requirements finding that "SCE's proposed AMI project will meet the minimum functionality criteria established by President Peevey."[3]

Chapter II of this exhibit provides a general overview of the Edison SmartConnect™ project and its deployment activities, objectives and functionality, including the project management structure, the overall deployment schedule, and a summary of costs and benefits. Chapter III details the planned activities and estimated costs and benefits for the Deployment Period based on the major functional areas of the Edison SmartConnect™ program: Acquisition of Meters and Communication Network Equipment; Installation of Meters and Communication Network; Implementation and Operation of New Back Office Systems; Customer Tariffs, Programs and Services; Customer Service Operations; and

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[1] *See* "Joint Assigned Commissioner and Administrative Law Judges Ruling Providing Guidance for the Advanced Metering Infrastructure Business Case Analysis, in R.02-06-001, dated 02/19/04, pp. 3 and 4.

[2] *See* D.05-12-001 for All part "Settlement Agreement" filed with the Commission by SCE, DRA, TURN and CCUE.

[3] D.07-07-042, Finding of Fact No.1.

Overall Program Management. Chapter IV provides a description of the estimated Contingency required for deployment. Chapter V summarizes the estimated costs and benefits during the Deployment Period, and includes estimated reductions in operational costs as well as avoided capacity and energy costs due to new demand response capabilities. All the dollar estimates in this exhibit are in nominal terms unless specified otherwise.

II.

OVERVIEW OF EDISON SMARTCONNECT™ DEPLOYMENT

This chapter provides a brief review of SCE's experience to date with advanced metering systems and describes SCE's overall approach to complete the system-wide deployment of the Edison SmartConnect™ meters, communications infrastructure, information technology (IT) systems and related new programs and services enabled by Edison SmartConnect™. This Chapter also identifies the total estimated deployment costs and benefits for each key deployment area.

A. Review of SCE's Experience with Advanced Metering Systems

Prior to undertaking the Edison SmartConnect™ business case analysis in 2004, SCE had already established itself as an industry leader in many respects:

- SCE has been a pioneer in developing, installing and operating automatic meter reading (AMR) systems with over 580,000 AMR meters installed;
- SCE also has over 20 years experience with advanced metering systems beginning with the Metricom meter in the late 1980s, with many still in service and through the 13,000 large commercial and industrial customers with Real Time Energy Meters (RTEM) meters initially installed earlier this decade; and
- SCE's two-way radio frequency telecommunications experience also includes one of the largest distribution automation networks in North America.

SCE's approach to AMI over the past three years has sparked a marked change in the industry definition of smart metering[4] and availability of commercial products to meet this need. Since 2005, SCE set about a deliberate and collaborative process with metering and communication system vendors to influence their product designs toward SCE's vision of a smart meter that integrated the next generation of advanced metering functionalities and capabilities. SCE's vision included many new product specifications to enhance the metering function, such as an open flexible metering and communications platform, home area network interface and a fully integrated service switch in all

[4] An example is the Texas Public Utilities Commission's smart meter rules issued in May 2007 that were based in part on SCE's requirements.

residential meters. In pursuing its vision, SCE became a key player and primary driver in bringing about this "next generation" of metering systems, which have become a reality in the marketplace.

As a result of SCE's efforts, Edison SmartConnect™ will not only meet the Commission's functionality requirements, but it will go even further to assure the long term feasibility of this major infrastructure replacement program and lasting benefits for SCE's customers. The improved metering and communication systems now available result in a $1 billion improvement in SCE's financial assessment since the initial 2005 cost benefit analysis was completed[5], going from a negative net present revenue requirement of approximately $950 million to a positive net present value revenue requirement of over $100 million.[6]

B. Description of Edison SmartConnect™ Project

Deploying Edison SmartConnect™ meters to all residential and business customers under 200 kW (approximately 5.3 million) over SCE's vast 50,000 square mile service territory within a five-year period is a major undertaking requiring reliable technology and capable, responsive vendors, a comprehensive deployment plan that seeks to reasonably mitigate risks, and provisions for contingencies. When installed, Edison SmartConnect™ technology will provide a two-way interface to each premise allowing for interval usage data in near real-time, direct communication to the meter to assist SCE in completing customer service-related requests, pricing signals and messaging to thermostats and load control switches at each premise, thus enabling valuable new dynamic tariff programs and services as well as energy information to encourage energy conservation.

1. Functionality of Edison SmartConnect™

When completed, the Edison SmartConnect™ system will have the capability to automatically read customers' meters on a daily basis, process and store validated 15 minute interval consumption data for C&I accounts and hourly data for residential accounts, and make stored data available for internal use and externally to the customer for their use in managing their energy usage.

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[5] *See* A.05-03-026.

[6] SCE's cost benefit analysis results are presented in Exhibit SCE-3) of this Application.

The system will also be able to support automatic meter reading for gas and water meters that may be of interest to gas and water utilities that overlap SCE's service area.

The Edison SmartConnect™ systems will provide the ability to turn electric services on and off remotely and it will make energy use information available to the customer either via the internet or directly through an in-home home area network (HAN) interface. SmartConnect will enable new customer tariff programs and services including new time-of-use (TOU) and critical peak pricing (CPP) rate options and enhanced residential smart thermostat load control programs. Edison SmartConnect™ will also provide improved energy forecasting methods to enhance SCE's energy procurement processes and it will provide improved customer outage and transformer loading information that is expected to reduce SCE's transformer replacement costs.

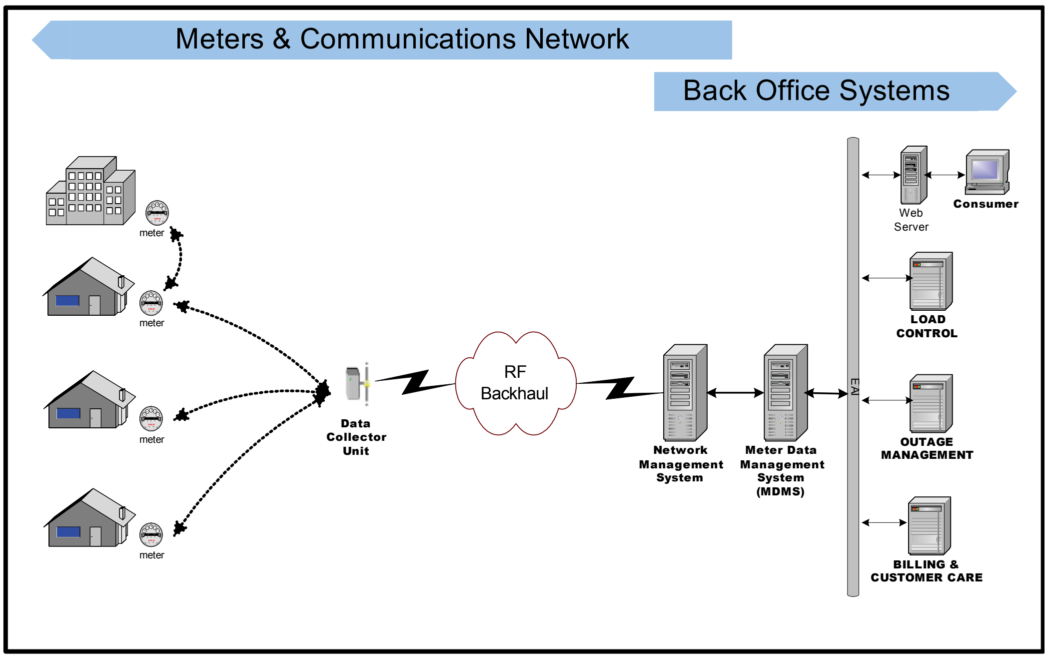
In order to deliver the expected benefits, SCE continues to work with the metering industry to develop products that satisfy or exceed the design requirements of Edison SmartConnect™. This new generation of meters is expected to deliver the following core functionalities:

- Two-way communication capability directly to each premise served by SCE;
- A minimum of 98 percent coverage for all electric customers in one system;
- Interval data in compliance with the Commission's requirements;
- Customer level voltage and tamper detection information;
- Enhanced outage information to aid assessment as well as restoration efforts;
- Integrated 200 amp electric service switch for most residential and small (under 20 kW) commercial customers (120/240V single phase service, 200 amps or less) with load limiting capability;
- Integrated HAN interface using a non-proprietary open standard to enable messaging to smart thermostats, in-home display, and/or customer devices;
- Communications interfaces to enable automated gas and/or water meter reading; and
- Remote upgrade capacity to the meter to support security and future flexibility.

2. Infrastructure Components

The infrastructure of the Edison SmartConnect™ project includes the advanced meters, the communication network and the new back office systems required to enable SCE to deliver the aforementioned functionalities. Figure II-1 shows how these primary components are divided between the field infrastructure (meters and communication network equipment) and the back office systems.

Figure II-1
Edison SmartConnect™ Infrastructure



The two primary aspects of deployment are: a) the implementation of this infrastructure and b) the execution of the various functionalities offered by this advanced system that will deliver customer value in terms of demand response and operational benefits.

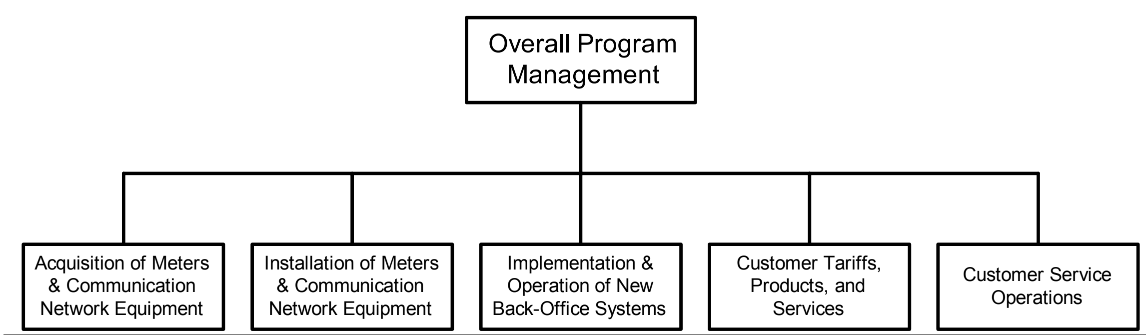
The components of the Edison SmartConnect™ system will collect, store, transmit, process, and transfer metering and other meter related data from various meter data collection points to various SCE network systems depending on the eventual application or use of the data (*i.e.,* billing, direct load control, outage management, energy procurement, *etc*.). Customers will also have access to their personal usage data for purposes of assessing their own energy usage patterns.

The essential elements of the meter and telecommunications network include the smart meters, the local area network (LAN) to collect and transmit the communicated meter, the wide area network (WAN) to backhaul the information to the utility data center, the Network Management System to manage and configure the network, and the Network Operating Center to provide network systems operations capability. The metering and communications network are described in more detail in Chapter III.A.2 below.

C. Description of Overall Edison SmartConnect™ Deployment Structure by Key Areas of Responsibility

As discussed in Section B above, Edison SmartConnect™ is a complex project of unprecedented scope and scale. In order to successfully execute this project, SCE organized the project management structure around the key areas of deployment. Central to this strategy is the use of industry best practices to manage the selection of the solutions and implement them in an efficient manner. As shown in the following Figure II-2, deployment activities are organized into four key functional areas of responsibility and the on-going Customer Service Operations that are impacted by the deployment process, each being implemented in accordance with industry best practices and incorporating its own past experience. Overarching these functional areas is the Program Management function, which provides project oversight of scope, schedule, budget and resources, as well as risk management for the entire program.

Figure II-2
Organizational Structure of Edison SmartConnect™ Deployment



The remainder of this volume is dedicated to detailing the execution of these key functional areas as described below:

- Overall Program Management – includes the oversight activities required to centrally manage a project of this scale and complexity, such as budgeting, compliance, and contract administration. It also includes risk-management, internal controls, and provision for contingencies needed to manage a project of this magnitude and complexity.
- Acquisition of Meters and Communication Network Equipment – includes the activities associated with selecting, purchasing, and testing the meters and the complementing communication network equipment that make up the field infrastructure.
- Installation of Meters and Communication Network Equipment – includes the field activities and vendor support required for installing the meters and communication network equipment.
- Implementation and Operation of New Back Office Systems – includes the activities associated with selecting and purchasing the new back office systems required to support the new metering infrastructure in addition to integration of these new applications with existing systems, and the expansion of the hardware necessary to accommodate the new applications and the exponential increase in customer usage information.
- Customer Tariffs, Programs and Services – includes the activities associated with developing, marketing, and administering the advanced tariffs, programs and services to customers that will provide the demand response benefits sought by the state's Energy Action Plan and facilitate customer education of their energy consumption habits and corresponding costs to help them make better energy usage decisions.
- Customer Service Operations – includes the on-going phone center and billing operations that will be impacted during the Deployment Period. This includes both the incremental costs and the incremental benefits expected to occur as the number of new meter installations ramp up throughout the Deployment Period.

Each of these program areas plays a critical role in the delivery of project benefits to SCE's customers. Each meter must: a) be properly and safely installed, b) be activated to securely communicate over the network in both directions, c) be recognized by the back office systems, and d) be enabled to deliver the new tariffs, programs and services to the customer. These areas are mutually dependent on one another and require management oversight and quality assurance to ensure an efficient deployment, accomplished in accordance with SCE's deployment plan and budget.

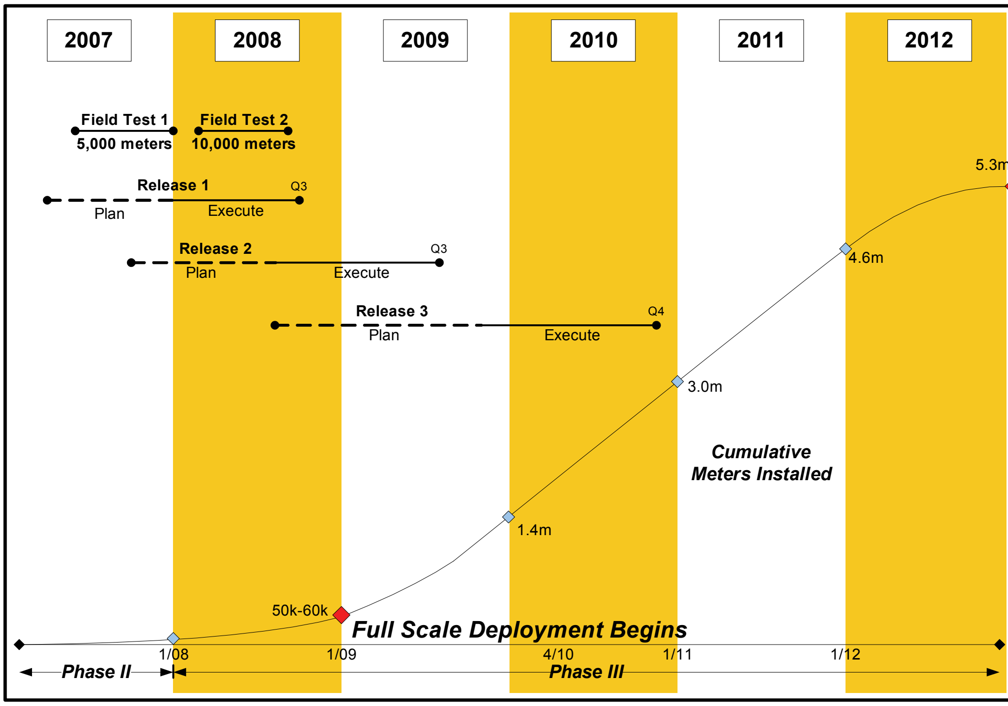
In SCE's deployment plan, the Customer Tariffs, Programs and Services functions are key drivers for the other three deployment functions. Rather than having metering and data processing constraints placed on new customer programs and tariffs (such as is the case today), with Edison SmartConnect™, the metering and data processing systems have been designed to meet the needs of the anticipated tariffs, programs and services. These critical interfaces are but one example of the level and complexity of SCE's comprehensive deployment plan.

D. Edison SmartConnect™ Release Strategy and Deployment Schedule

SCE is planning to deploy smart meters to all residential and business customers (below 200 kW) beginning in 2008 with a second field test (Field Test 2) and ramping to full scale deployment in January 2009 for completion in 2012. Concurrently, SCE will develop the back office systems to support the operations and enable the new Edison SmartConnect™ functionality. Given the scale and complexity of the functionalities enabled by Edison SmartConnect™, SCE plans to implement these functionalities over three separate release periods. SCE may include a fourth release of functionality to maximize the value to customers during the Deployment Period. Full functionality is expected to be available by 2012.

Figure II-3 shows how the overall project schedule prioritizes the releases with the Field Tests and the ramp-up of meter installations.

Figure II-3
Deployment Schedule



1. Release Strategy

The functionality of the Edison SmartConnect™ meters and back office systems will be implemented under three separate planned release periods, with each release providing additional customer support functions. As noted earlier, SCE may include a fourth release of functionality during the Deployment Period. Execution of the back office systems being developed in each release will be field tested as an integral part of the metering and communication system installation strategy.

a) Release 1

For Release 1, SCE will identify, design, develop and implement all the necessary enhancements to and integration with SCE legacy systems that will allow the collection of customer usage data from the Edison SmartConnect™ meter through the network management system and the Meter Data Management System (MDMS) to the billing system. This release will allow SCE to obtain customer usage information in a timely manner and produce an accurate bill for SCE's customers. These activities are also referred to as "meter-to-revenue" functions. There are additional core functions that will be designed, developed and implemented as part of the Release 1 activities planned for operation in 2008. These core functions include: completely automated meter reading, a semi-automated service switch that will allow SCE to perform routine turn–on, turn–off, and disconnect/reconnect orders remotely, the ability to provide customers with web-based interval usage data (*e.g.,* next day presentment – hourly intervals for residential customers and 15 minute intervals for nonresidential customers), and in-home energy information for customers through the HAN. SCE will execute the development of these Release 1 functions starting in early 2008 and expects to complete the work by third quarter 2008. Starting in 2008, SCE plans to use the new Edison SmartConnect™ meters for new meter sets supporting customer growth.

b) Release 2

In Release 2, SCE will design, develop and implement all necessary enhancements and integration with existing SCE legacy systems that will allow SCE to offer new customer-oriented programs such as load management programs and customer services such as customer access to usage information through a web-based portal. As such, the functions in Release 2 will allow SCE to fully automate the service switch in order to implement a completely automated service connection and disconnection orders and enhance the revenue protection and meter tamper detection functions in existing SCE systems. Importantly, in Release 2 SCE will develop and implement the necessary enhancements to existing load management systems to be able to offer an expanded portfolio of load control, demand response, and dynamic pricing options such as TOU, Peak Time Rebate (PTR) and CPP. The Release 2 function will also include integration of the MDMS with the new customer care systems that SCE will implement in 2009 as part of a separate deployment of SAP, a large enterprise application.[7] SCE expects to begin the Release 2 planning activities in the fourth quarter 2007 and expects to execute the development of these functions in mid-2008 and will be complete with these functions by third quarter 2009.

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[7] In the event of changes to the SAP deployment, it may be necessary to alternatively enhance the existing systems to support the Edison SmartConnect™ functionality.

c) Release 3

In Release 3, SCE will design, develop and implement all necessary enhancements to and integration with other existing SCE legacy systems that will allow SCE to improve its energy forecasting and outage management functionality. In addition, the Release 3 functions will allow SCE to further expand its portfolio of customer care services (*e.g.,* enhanced bill and payment options). SCE will begin planning activities for the Release 3 functions in early 2008 and expects to execute the system development of these functions in late-2008 and will be complete with these functions by the 2011.

2. Field Testing

SCE's field testing started with Field Test 1, a pre-deployment activity that includes the installation of as many as 5,000 Edison SmartConnect™ meters. Field Test 1 is focused on testing the functionality and coverage of the two distinct field infrastructure solutions still being considered by SCE. Field Test 1 results will ultimately determine the selection of SCE's primary metering and communication system vendor. The metering and communication systems installed for Field Test 1 together with the initial Field Test 2 meters will serve as the testing ground for the execution of Release 1 functionality testing.

A primary purpose of Field Test 2, scheduled for the first half of 2008, is to work out the intricacies of installation policies and procedures for the installation contractor and SCE's installation team. Field Test 2 includes up to 10,000 meters and is designed to test the meter installation vendor processes under high volume conditions. This will provide valuable information needed to facilitate the transition to full scale deployment in January 2009. Field Test 2 will also serve as the testing ground for Release 1 functionality in the second half of 2008. As shown in Figure II-3, full scale deployment is targeted to begin in 2009 and will be completed in 2012. Starting in January 2009 and ending in 2012, SCE plans to deploy Edison SmartConnect™ meters to all residential and business customers under 200 kW (approximately 5.3 million meters) at an average rate of about 6,000 meters per work day across multiple separate regions simultaneously.

E. Edison SmartConnect™ Deployment Costs and Benefits

SCE's proposed deployment costs and the cost recovery mechanism presented in Exhibit SCE-5 supporting this Application include the costs and benefits expected to be incurred during the Deployment Period.[8] Pre-deployment costs incurred prior to 2008 have already been authorized in prior proceedings and are currently being recovered through the Advanced Metering Infrastructure Balancing Account (AMIBA). Costs and benefits incurred after 2012 (post deployment) are considered to be on-going operating costs and will be recovered through future GRC proceedings. Edison SmartConnect™ costs have been isolated into these timeframes solely for ratemaking and cost recovery purposes.[9]

The estimated costs for the Edison SmartConnect™ project over the Deployment Period are estimated at $1.7 billion. Table II-1 summarizes the costs by program area during the Deployment Period. Deployment period costs and benefits will be discussed in more detail in Chapter V of this Exhibit.

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[8] This Application also requests authorization to transfer certain "deployment" costs proposed in this Application but incurred in 2007 and recorded in SCE's AMI Memorandum Account to the Edison SmartConnect Balancing Account upon a final decision in this proceeding, as contemplated in D.07-07-042, SCE's Phase II Decision.

[9] SCE's Business Case for Edison SmartConnect™ is based on a net present value of all costs and benefits to be realized over the entire life of the project. This analysis is the subject of Exhibit SCE-3 of this Application.

Table II-1
Estimated Costs and Benefits During the Deployment Period
(Millions of Nominal Dollars, Rounded)

Line No.	Description	O&M	Capital	Totals
1.	**Costs**			
2.	Acquisition of Meters and Communication Network Equipment	1.6	836.5	838.0
3.	Installation of Meters and Communication Network Equipment	79.6	216.9	296.6
4.	Implementation and Operation of New Back Office Systems	41.4	149.8	191.2
5.	Customer Tariffs, Programs and Services Costs	112.1	0.0	112.1
6.	Customer Service Operations	78.9	5.2	84.1
7.	Overall Program Management	37.5	8.1	45.6
8.	Contingency	33.0	114.3	147.3
9.	**Costs Totals**	**384.2**	**1,330.7**	**1,714.9**
10.	**Benefits**			
11.	Operational	188.4	89.9	278.2
12.	Demand Response	144.4	71.8	216.2
13.	**Benefits Totals**	**332.8**	**161.6**	**494.4**

III.

DESCRIPTION OF KEY DEPLOYMENT AREAS OF EDISON SMARTCONNECT™

The four key areas of responsibility included in SCE's Overall Edison SmartConnect™ Deployment Structure along with the customer service operational impacts include:

- Acquisition of Meters and Communication Network Equipment
- Installation of Meters and Communication Network Equipment
- Implementation of New Back Office Systems
- Customer Tariffs, Programs and Services

This section provides a detailed overview and description of each of these areas of responsibility, including a discussion of the project management oversight for each area, the contingency planning and risk mitigation considerations, and a summary of the project cost estimates for each key area. In addition, this section describes the impact Edison SmartConnect™ is expected to have on SCE's on-going customer service operations and it will include an overview of the Overall Program Management and its key functions.

A. Acquisition of Meters and Communication Network Equipment

The Edison SmartConnect™ Program involves the acquisition and installation of over five million smart electric meters and a telecommunication network that enables two-way communications throughout SCE's 50,000 square mile service territory.

1. Overview of the Acquisition Processes

The Edison SmartConnect™ metering and communications systems will be selected through a rigorous and competitive vendor selection process. This selection process began in late 2005 as part of Phase I and continues through SCE's Phase II pre-deployment.[10] The estimated expenditures for acquiring the metering and telecommunications network equipment are based on following considerations:

[10] For additional details regarding SCE's vendor selection process, see Phase I and Phase II applications (A.05-03-026 and A.06-12-026) and Phase I Conceptual Feasibility Report released on August 7, 2006.

- The acquisition process was structured so that the selected vendors have sufficient resources, credibility, and expertise to supply necessary equipment and services to complete their work within the permitted timeframe and agreed budget. This also included detailed analyses and testing of vendor equipment by the program team and consultations with outside experts and other utilities with direct experience using or testing the finalist vendors' technology. The competitive bidding process resulted in a narrowed selection of solutions offering the best performance and financial value that will meet and exceed the Commission's functionality objectives.
- SCE has analyzed the uncertainties and risks associated with its selected technology options and developed appropriate measures to mitigate and manage these uncertainties and risks. For example, SCE is currently negotiating detailed terms and conditions with its selected vendors and suppliers so that SCE obtains the full value of procured materials and services and properly manages the risks of vendor or product non-performance. SCE included in its Request for Proposal (RFP) package a proposed set of terms and conditions that were developed with assistance from outside counsel.

2. Description of Meters and Communication Network Equipment

The essential elements of the meter and telecommunications network are:

- SCE specified smart meters to read and communicate the electric service data from each customer delivery point, and communicate directly with optional in-home thermostats and other compatible devices (and to have the ability to be reprogrammed and upgraded remotely;
- The AMI two-way LAN to collect and transmit the communicated meter data or support other Edison SmartConnect™ applications;
- The WAN to backhaul the information from the meter and LAN to the utility data center;

- The network management system (Network Management System) to manage and configure the network; and
- The Network Operating Center (NOC) to provide network systems operations capability.

As such, the purchase and installation of smart meters, modules, network equipment and systems and necessary infrastructure support is required and is the critical foundation to the Edison SmartConnect™ Program.

a) Data Capabilities

The final technologies SCE is considering for its Edison SmartConnect™ meters will deliver interval data on a pre-determined schedule that supplies data in 15-minute intervals for commercial customers and hourly intervals for residential customers. The customer usage data recorded at the meter will be retrieved periodically through the day and stored in a database for future operational uses and in support of any required tariff design structures. The Edison SmartConnect™ technology possesses the capability to collect more frequent interval data for residential customers. For example, SCE anticipates that it may use more frequent interval collection on customers participating in load control programs, customer samples for load research and distribution engineering analyses. The smart meters will be able to store interval data to at least a 5 minute frequency. While this can be implemented on an exception basis when required, the network system and back office systems SCE is designing would not support this frequency of meter data collection for all customers. Any proposed changes to retrieve greater amounts of data would need to be evaluated and a determination made whether additional costs would be necessary to upgrade the systems and infrastructure. This limitation is overcome, in part, with the ability of the smart meters to provide customers with direct access to near real-time 5 second interval data directly from the meter via the HAN interface.

b) Coverage Capabilities

Each electric meter will communicate via radio frequency (RF) communications network equipment installed throughout SCE's service territory. SCE serves a 50,000 square mile area, but nearly 88 percent of SCE's customers live within only 15 percent of the total area. SCE's experience with two-way RF networks and the responses and test results by SCE and other utilities provide a high confidence that a single RF network will be able to achieve the design objective of 98 percent or greater coverage. Depending on the final communications vendor selected, if a separate wide area network service is required, the network will utilize either cellular service or a wireless broadband service. In this regard, SCE continues to evaluate the wide area network options (*e.g.,* Cellular, Muni WiFi, WiMax, BPL) as the market continues to evolve. If a separate WAN service is needed, SCE expects to pursue a dual option in the network collectors for cellular and broadband backhaul. SCE also intends to work with the selected vendor to ensure the products comply with SCE's Information Assurance (security) requirements.[11] SCE anticipates a variety of means to reach the remaining 1-2 percent of customers utilizing alternate RF technology, telephone line, satellite, or possibly mobile for the most challenging sites. SCE does not expect the AMI communications network choice to preclude the potential use of SCE's distribution lines for broadband over powerline.

3. Managing the Acquisition of Meters and Communication Network

The acquisition process involved an extensive collaborative process that began with a massive communications effort with several hundred prospective metering and communication systems vendors. This effort started in November 2005 with a Request for Information (RFI) and will end with the conclusion of the RFP process and the awarding of procurement contracts in late 2007. The RFP process started in December 2006 with six sets of vendors, which was narrowed down to two sets of vendors for field testing during Phase II. A third vendor's product will continue to undergo lab testing in 2007. Each set of vendors represent an integrated field infrastructure composed of meters and communication network equipment with a Network Management System. Final vendor selection is expected by end of 2007.

SCE's requirements, as described in Section II.A.1, were a challenge for most vendors as SCE sought to maximize the functionality and architectural flexibility of the proposed Edison SmartConnect™ system within a relatively short timeframe. SCE found that the RF fixed network

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[11] As defined in SCE's Metering and Telecommunications System RFP.

systems produced the optimal functionality, coverage and overall value for its customers. This is based on SCE's plans to provide new customer choices for automated services, information and energy management beyond what is offered today. Examples include: in-home energy information and messaging, smart thermostat control, support for plug-in hybrid electric vehicles and distributed resources metering, and contract automated gas and/or water meter reads. Edison SmartConnect™ systems will also support numerous functionality upgrades and enhancements in the future, thus mitigating the risks of functional and technical obsolescence.

In summary, SCE expects that selected technologies will be effective, will achieve the Commission's functionality objectives, and will meet the current and future needs of its customers and utility operations. Based on RFP responses and initial negotiations, both finalist vendors' products meet SCE's price targets needed for a cost effective business case.

a) Alternative Edison SmartConnect™ Technology Approaches Considered by SCE

During the RFI, RFP and vendor selection process, SCE analyzed a number of meter and telecommunications technologies to determine which technology would be most appropriate for SCE's specific service territory and customer base and which technology would provide the most cost effective approach to achieve the functionality objectives articulated by the Commission and SCE. SCE's evaluation process included the consideration of costs and benefits, functionality features (*e.g.,* meeting basic remote interval reading requirements, and future adaptability) and risks (*e.g.,* product maturity, company stability, schedule, and technical risks) associated with each technology option. SCE's rigorous vendor selection process began with a RFI in December 2005 that was sent to over 130 vendors worldwide and resulted in responses from 43 vendors. The AMI LAN technologies represented included:

- Narrowband wireless network solutions utilizing mesh or licensed tower based technologies;
- Power Line Carrier solutions;
- Wireless Broadband solutions; and
- Broadband over Power Line solutions

SCE gave careful consideration to each of the technologies within the context of seeking to obtain smart meter and telecommunications technology that would provide a reasonable assurance of meeting the Commission's functionality objectives and SCE's requirements for the Edison SmartConnect™ Program at a cost-effective price and within the defined program schedule. This includes a careful assessment of the vendors' ability to scale production and support to meet not only SCE's procurement needs but the significant market demand in North America for AMI systems.

b) Current Status of Acquisition Process

SCE intends to replace all SCE-owned residential meters and commercial meters up to 200 kW with new smart meters.[12] SCE's meter population includes a number of different types and sizes to accommodate different customer service levels. All new Edison SmartConnect™ meters will be shipped with the Edison SmartConnect™ functionalities already built into the meter. After a long and rigorous vender selection process, based on its detailed analysis of AMI technology options, SCE has narrowed the choices to Cellnet/Landis+Gyr, Itron and Sensus for final evaluation to supply technology for the Edison SmartConnect™ integrated meters and associated fixed radio frequency (RF) network. SCE is confident that it will be able to make a final selection by the end of 2007 from among these vendors.

Table III-2 shows how SCE's collaboration with meter manufacturers have successfully resulted in a new generation of meters robust enough to effectively deliver benefits over the long run.

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[12] All SCE customers with demands exceeding 200 kW already have smart meters installed.

Table III-2
Edison SmartConnect™ Functionalities

Feature/Function	SCE's Design	Availability in 2005	Expected Availability by 2008
Remote Interval & On-Demand Reading	Yes	Yes	Yes
Maximum Power Consumption	Yes	Yes	Yes
Remote Curtailment – demand limiting	Yes	Yes	Yes
Remote Connect/Disconnect	Yes	Yes	Yes
Energy Use Display – Text messaging & enhanced features[2]	Yes	Yes	Yes
>35 Days of On-Board Memory	Yes	Yes	Yes
Continuous Service Monitoring	Yes	Yes	Yes
Pre-payment	Yes	Yes	Yes
Multiple Data Ports	Yes	No	Yes
RF Link to In Home Devices[2]	Yes	No	Yes
Wireless Link to Gas/Water Meters	Yes	No	Yes
Integrated Load Control[2]	Yes	No	Yes
Two-leg voltage Measurement[1]	Yes	No	Yes
Integrated GPS	Yes	No	No
Multi-RTU Protocol[1]	Yes	No	No
>15 Year Life Expectancy	Yes	No	Yes
Energy Display Trip Counter[2]	Yes	No	Yes
Local Area Sensor	Yes	No	No
Net Energy Measurement	Yes	No	Yes

[1]This feature is available in limited instances, generally for commercial and industrial meter applications.

[2]With incorporation of an integrated HAN, this feature may be supported with "add-on" devices developed and marketed by other third party manufacturers.

4. Risk Management of the Procurement Process

There are various uncertainties and risks that may affect the procurement and installation of telecommunications equipment and network operations. SCE analyzed these uncertainties and risks including: vendor, technology, unforeseeable site/meter conditions, implementation and operations and is in the process of developing procedures and processes to effectively manage these uncertainties and risks.

a) Vendor Risk

SCE will manage vendor risk by selecting a firm that has the capability, financial standing and proven track record to support their technology and services. SCE has extensive commercial experience with the network vendors chosen to field test products. The communications vendors remaining in consideration are among the top five industry suppliers in terms of installed base for AMR/AMI networks. An integral element of SCE's RFP process for network vendors is negotiating the terms and conditions that will reduce supplier related risks during the Deployment Period. SCE expects certain price and performance warranties from its vendors based on the level and length of business a project of this scale provides for the vendor community.

Similarly, SCE plans to utilize the same tactics for developing the terms and conditions with meter suppliers. As stated, SCE is currently testing three meter manufacturers. To be cost effective, SCE plans to select one meter manufacturer as the primary meter supplier to take advantage of volume related discounts. However, to hedge against potential supplier concentration related risks, SCE is also planning to select at least one additional meter manufacturer to provide products during the Deployment Period.

b) Pricing Risk

SCE will manage this risk by contractually obligating each selected vendor to deliver its products at the prices quoted in the vendor's competitive bid submitted as part SCE's RFP process. SCE will also manage pricing risk by having at least two meter suppliers, at least one of which is able to replace commercial as well as residential meters. As part of the RFP, each meter supplier will be required to demonstrate that it can provide a meter that includes a communications card procured from the communications supplier and a disconnect switch, among other required components, integrated under the meter cover.

SCE anticipates the integration of the communications solution into two separate meter vendors' products. The first of these integrated meter products (Meter 1) will be tested in Field Test 1. Once the communications solution is selected at the end of 2007, that communications supplier's communications card will be expected to be integrated into a second meter (Meter 2) which will be tested in 2008, as part of Field Test 2. One of the two meter vendors is also expected to provide commercial and industrial meters, which have been integrated with the communications solution.

c) Technology Risk

(1) Communications

SCE rigorously analyzed various technologies and their associated costs prior to the choice of using a RF fixed network for Edison SmartConnect™. Based on functionality, price, and risk, the RF technology for the Edison SmartConnect™ system provides SCE and its customers with the greatest value. The basic metering and RF technology is proven and SCE has over a decade of experience with one of the largest two-way mesh networks in operation.

(2) Assumed Meter Failure Rates

SCE conducted extensive lab testing, including accelerated life testing to assess failure rates. Additionally, SCE and its consultant (the engineering and manufacturing division of IBM) conducted manufacturing plant audits of the finalist vendors in Spring 2007. Lastly, SCE also considered vendor technical and commercial information provided in the RFP responses to estimate electric meter/module failure rates. The integrated meter failure rates incorporated into SCE's cost estimates are based on vendor information and SCE's independent assessments. SCE estimates the smart meters to have failure rates of no more than .5 percent[13] and a service life of 20 years.

SCE is managing the risk of equipment failures through contractual terms and an ongoing quality management effort with the vendors. SCE is establishing contract terms and conditions related to product warranties and vendor liability for non-performance. SCE is proposing to continue the effort begun in Phase II pre-deployment to actively engage the selected vendor in a quality management program to ensure manufactured products and the component parts meet SCE's performance requirements. SCE's quality management effort spans the entire supply chain from source components to design and manufacture to acceptance testing and field performance evaluation. SCE will continue to work with the vendor to ensure a robust quality management program and engaging the upstream suppliers to ensure a reliable supply of quality components in order to minimize customer impacts, potential safety hazards, and expensive replacements due to faulty equipment. SCE will also

[13] SCE assumes that 1% of the smart meters will require site visits. Of the 1%, only .5% are assumed to be failures; the other .5% are assumed to be reusable.

continue to leverage consultants with industrial electronics engineering and manufacturing quality management to assist in site audits, root cause analysis and vendor performance reviews. SCE will perform acceptance tests on the meters and anticipates the intensity of acceptance testing will be higher during field tests and the earlier portion of mass installation, eventually ramping down to statistically significant sample standards as full deployment progresses. SCE plans to expand its existing industry leading meter testing facilities and leverage internal expertise throughout the Deployment Period.

5. Cost Elements for Acquisition of Meters and Communication Network Equipment

Table III-3 provides the estimated O&M and capital costs related to the acquisition of meters and the communication network. As shown in that table, 97 percent of these deployment costs are related to purchasing the key field infrastructure components: meters and communication network equipment. The remaining capital expenditures such as installation of a new conveyor belt system, one new demand board and two new test boards are required to support acceptance testing activities. Other capital expenditures include purchase of A-base adaptors and antennas to facilitate installation of Edison SmartConnect™ meters. This also includes the capitalized labor for performing the acceptance testing, engineering of a percentage of the complex meter installations, as well as project management of the meter vendors.

Table III-3
Estimated Costs for Acquisition of Meters and Communication Network Equipment
(Millions of Nominal Dollars, Rounded)

Line No.	Description	O&M	Capital	Totals
1.	Cost of Meters and Communications Equipment	0.0	810.1	810.1
2.	Vendor Management & Acceptance Testing	1.6	26.4	27.9
3.	**Totals**	**1.6**	**836.5**	**838.0**

a) Cost Drivers for Meters and Communications Equipment Acquisition

There are essentially two key cost drivers for the capital costs in this program area. The first cost driver relates to the acquisition of the Edison SmartConnect™ meter that SCE will install throughout its service territory. The meter vendors' RFP responses met SCE's price point for residential meters. However, actual meter costs may vary due to commercial meters and final negotiated terms, including possible warranties on single phase residential meters.

The second key cost driver for the capital costs in this program area is the communication network equipment installed in the field to facilitate the wireless exchange of information in its 50,000 square miles service territory from the meter to SCE's back office systems. The communication network equipment capital expenditures in this program area also includes the network management system (referred to as the Data Center Aggregator or DCA in SCE's pre-deployment application) that is required to compile the customer usage data from the meter or disseminate information from its back office systems to the meter. Because the network management system is bundled with the communication network equipment, the cost of the acquiring communication network equipment, including the network management system is included in these estimates. However, the forecast costs to integrate the network management system with SCE's back office are included in the Implementation of New Back Office Systems section, Chapter III, Section C.4 of this exhibit.

b) Cost Drivers for Vendor Management and Quality Management Activities

The key functions that comprise the cost drivers for vendor management and quality management activities are: vendor management of the meter and telecommunications vendor(s); quality management personnel, consulting engineers, and acceptance testing; engineering and support for a percentage of the complex meter installations. As shown in Table III-2, the estimated costs for these functions are capital costs in support of the new meter installations. A relatively small portion of the forecast O&M expenditures are costs associated with salvaging electronic meters to meet environmental mandates.

The first activity, quality management, is the largest activity in this functional area. SCE is proposing to continue the effort begun during pre-deployment to actively engage the selected vendor in a quality management program so that manufactured products and the component parts meet SCE's performance requirements. SCE's quality management effort spans the entire supply chain from source components to design and manufacture to acceptance testing and field performance evaluation. SCE will continue to work with the vendor to ensure a robust quality management program and engaging the upstream suppliers to ensure a reliable supply of quality components in order to minimize customer impacts, potential safety hazards, and expensive replacements due to faulty equipment. SCE will also continue to leverage consultants with industrial electronics engineering and manufacturing quality management to assist in site audits, root cause analysis and vendor performance review. Product acceptance testing involves setting up the meters on test boards and performing accuracy testing, functionality testing and communication testing on each individual meter until such time that meter quality allows for a statistical sample of meters to be tested. The forecast capital expenditures for the acceptance testing area relate to the tools and specialized equipment needed to conduct the acceptance tests and the capitalized labor associated with performing the tests.

The second activity in this area relates to managing the meter and telecommunication vendors that are selected through the RFP process. The vendor management costs are capitalized during the Deployment Period. This critical activity involves managing vendors' product development process to SCE's deployment timeline and the delivery schedule for the various products required to meet its installation plan. Additional vendor management activities include working with vendors to continue to improve their products and coordinating the industry standards development for AMI technologies.

c) Expected Annual Expenditures for Acquisition of Meters and Communication Network Equipment

Table III-4 shows the annual expenditures for the Acquisition of Meters and Communication Network Equipment by capital and O&M expenditures during the Deployment Period. As previously stated, SCE plans to initiate mass meter deployment in 2009 and complete this deployment in 2012. During 2008, a small portion of the costs in this area will support the refinement of mass deployment related policies, procedures, processes, and systems related to Acquisition of Meters and Communications Network Equipment. Consistent with its deployment schedule, the expenditures in this program area significantly ramp up in 2009 as the full deployment levels are reached.

Table III-4
Expected Annual Expenditures for Acquisition of Meters and Communication Network Equipment
(Millions of Nominal Dollars, Rounded)

Line No.	Description	2007	2008	2009	2010	2011	2012	Totals
1.	O&M	0.0	0.0	0.3	0.5	0.5	0.3	1.6
2.	Capital	0.0	36.7	213.0	247.5	241.9	97.3	836.5
3.	**Totals**	**0.0**	**36.7**	**213.4**	**247.9**	**242.4**	**97.6**	**838.0**

B. Installation of Meters and Communication Network Equipment

Replacing the entire metering infrastructure in its service territory of 50,000 square miles is one of the most significant projects ever undertaken by SCE. During 2008, SCE will work with its meter and communication system installation contractors to refine the installation processes and integrate the contractors' inventory and work management systems with SCE's systems. A primary purpose of the field test scheduled for the first half of 2008 is to work out the intricacies of installation policies and procedures for the installation contractor and SCE's installation team.

1. Overview of the Installation of Meters and Communication Equipment

During the Deployment Period, SCE plans to deploy more than 5 million meters at an average rate of about 6,000 meters per work day. This rate of deployment is one of the industry's largest, but the daily rate of deployment is less than that successfully completed by Progress Energy.[14] SCE will work with its selected primary contractor, to develop the detailed installation plan, taking into account a variety of factors, including:

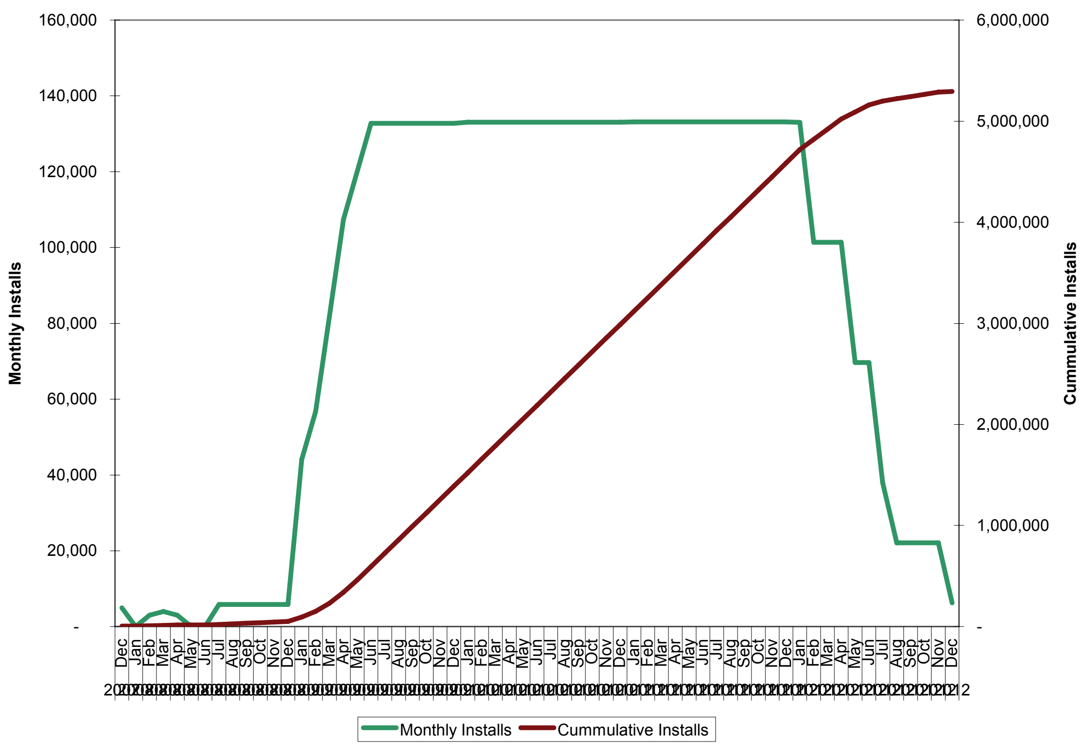
- Maximizing operational and demand response benefits;
- Impacts on SCE's meter services operations and people;
- Coordination with SCE's T&D organization;
- Existing contract water and gas meter reading customers;
- Telecommunications network deployment; and

[14] Progress Energy deployed about 2.5 million meters within two years at a peak average of about 10,000 meters/day. The meters were part of an AMR system, however, Progress Energy's electronic meter installation is comparable from a deployment process perspective.

- Program schedule, costs and risk considerations.

A final detailed deployment plan will be completed in mid 2008 after Field Test 2 results. The AMI communications network equipment installation plan will depend on the final communications vendor selected, because their technologies have different installation requirements. One vendor's collector is installed in the base of the meter, another vendor requires a pole-mounted collector/radio and the third vendor utilizes a tower based network. The telecommunications vendor will be selected at the end of 2007 and the experience of the field test in Phase II will also influence the final plan. Figure III-4 below illustrates the overall meter installation plan.

Figure III-4
Installation Plan



2. <u>Installation of Meters and Communication Equipment Planned Activities</u>

Approximately 92 percent of SCE's current meter population are simple, routine, single phase meter installations, primarily residential and small commercial (under 20 kW) that can be accomplished by personnel with only a moderate level of training and technical expertise. The other 8 percent of meter retrofits are more complex metering systems, usually associated with medium size (over 20 kW) commercial customers, difficult to access residential meters and new customer meter sets. SCE conducted an extensive benchmarking survey of utility meter deployments in North America to determine industry best practices for mass meter installation. In that effort, SCE visited PG&E, SDG&E, Dominion, We Energies, Progress Energy, PECO, and PPL. It became clear that the challenge of such a major undertaking on SCE's existing workforce would be very costly not only from the standpoint of the program, but also in terms of the impact it would have on SCE's employees and its on-going operational functions, which must continue in parallel for the existing meters while field installations of the new smart meters are taking place over a five year period. Based on industry best practice, SCE has decided to outsource 83 percent of the total meter installs to a specialized deployment contractor using union labor for the installation of the field infrastructure, composed of both the meters and communication network equipment. This approach not only offers the lowest potential cost, but also reduces the overall operational and program risk. SCE will staff a project management team to oversee the Field Deployment including both the deployment contractor and SCE's deployment team which will be installing the remaining 17 percent of the total meters during the Deployment Period.

a) Outsourced Installations

SCE utilized a thorough RFP process at the beginning of pre-deployment phase to identify and select a qualified deployment contractor. SCE leveraged the best practices and lessons learned in the industry in developing its RFP. For example, SCE negotiated a Project Labor Agreement with Local 47 of the International Brotherhood of Electrical Workers (IBEW), that provides labor rates and work rules for the Edison SmartConnect™ program so that vendors would be able to respond to the RFP with a key input (labor costs) known in advance. In addition, SCE also provided contractual terms and conditions as part of the RFP to consider commercial terms as part of the evaluation. SCE's procurement process included an evaluation of the proposals and a best and final proposal from a selected group of contractors. SCE's final evaluation included an extensive due diligence process for the selected contractors including:

- Inspection of contractors' facilities at reference utility clients
- Inspection of contractors' completed and active job sites

- Interviews with contractors' employees
- Assessment of contractors' management team
- Assessment of contractors' policies and procedures, including safety
- Assessment of contractors' ability to scale to support the size of SCE's deployment
- Interviews with contractors' past and existing utility customers

SCE has elected to use a single deployment contractor based on the contractor responses to the RFP, results of due diligence, compliance with SCE's proposed terms and conditions, deployment risk assessment, and the contractors' final price proposals. SCE selected Corix as its meter deployment contractor. Corix (formerly Terasen Water and Utility Services) is based in Surrey, British Columbia and has more than 65 years of experience designing, building, and managing vital utility infrastructure systems. Corix's utility-based business practices, management and organizational capability, inventory and deployment processes and systems, and pricing provided the best match to SCE's objectives. This deployment will be Corix's largest to-date, but SCE's due diligence indicates that they will be able to scale to meet SCE's needs and have sufficient organizational maturity to be successful over the Deployment Period.

b) SCE Installations

The 17 percent of meters to be installed by SCE resources are composed of: a) about 8 percent for replacement of existing meters for medium commercial customers (20kw to 200kw), b) about 3 percent for replacement of existing residential and small commercial (<20kw) customers that the deployment contractor is unable to complete for reasons such as access issues, and c) about 6 percent for new meter sets for residential and small commercial customers during the Deployment Period. All SCE installations will be performed by SCE employees. Meter Technicians will be used to replace existing and perform new meter sets for all complex commercial meters, including three phase self contained meters, Current Transformer (CT) and Potential Transformer (PT) meters. Field Service Representatives will perform new meter sets, replace all meters that the deployment contractor is unable to complete, and perform all A-Base meter replacements.

3. Managing the Installation of the Metering and Communications Network

The meter deployment will be based upon a detailed meter installation plan. In order to execute the installation plan, numerous logistics must be coordinated including supply chain, material availability, facilities, training, workload management, data management, customer communications and personnel/resources. The Deployment Contractor, Corix, will provide sufficient management support and organizational structure to provide leadership and staffing over critical implementation functions including safety, planning, performance tracking, work order management/data management, dispatching, customer call center/communications, training, human resources, inventory management, IT, quality assurance and field supervision/technicians. The Corix on-site project resources required at peak installation output times is estimated at 215 full time equivalents. Varying levels of Corix corporate support will also be required during deployment.

SCE will staff a field deployment organization to manage the deployment contractor as well as coordinate with other deployment-involved organizations within SCE. The SCE Field Deployment Organization will consist of the following major functional groups: safety compliance, field logistics & supply chain management, performance tracking, analysis and planning, quality assurance, project management over SCE resources, and contractor management. Detailed project plans will be developed with specific accountability assigned to the various field deployment resources to keep the deployment on schedule. Business processes and required interfaces will be developed in detail and tested as part of Field Test 2 prior to beginning full deployment.

The installation of the communications network will be managed by the Field Deployment Organization. If the selected communications technology requires pole-mounted radios/collectors, a contractor will be hired to complete the installations. These installations will be coordinated with the meter installations to maximize the benefits realized and mitigate potential operational issues. The business case reflects pole-mounted collectors, which is a conservative approach to estimating the cost impacts. Should the collectors ultimately be part of the meter itself, then the actual cost for this activity will be reflected in the cost recovery mechanism so that customers only pay for the actual costs incurred. This cost recovery mechanism is described in Exhibit SCE-5.

4. Risk Management of the Metering and Communications Network Installations

Through detailed planning and risk assessment, business processes will be developed ahead of time to deal with a majority of issues expected to be encountered during deployment. Mitigation strategies have also been discussed for other issues that may arise. The principal installation related risk areas and mitigation measures are:

- Vendor Installation Quality: Contract terms with incentives and penalties to align contractor interests with SCE's interests to ensure accurate installations and transfer of installation data.
- Vendor Staffing and Productivity: SCE has negotiated a Project Labor Agreement with IBEW Local 47 pay rates into the deployment contract. The pay rates are similar to the rates SCE has had success with hiring and retaining employees to perform the type of work the contractor employees will be performing. Should the deployment contractor fall significantly behind schedule, the terms of the agreement allow for a second contractor to be engaged.
- Vendor Default: In the event the deployment contractor defaults, SCE has contractually required access and the ability to continue to use Corix's work and inventory management systems which would significantly shorten any downtime should this occur.
- SCE Installation Productivity: If SCE's deployment efforts fall behind schedule, the deployment vendor does have the capability to provide the requisite skilled union personnel to augment the SCE deployment team.

5. Estimated Costs for Installation of Meters and Communication Network

Table III-5 shows the estimated O&M and capital costs needed to install Edison SmartConnect™'s field infrastructure during the Deployment Period. These forecast costs are comprised of two functions: Outsourced Installations and SCE Installations. As shown in Table III-5, 74 percent of the estimated costs for this program area relate to capital expenditures. Over half of these total forecast capital expenditures are for Outsourced Installations. All of the estimated O&M expense relates to certain aspects of SCE Installations. The cost drivers are discussed in subsequent portions of this section.

Table III-5
Estimated Costs for Installation of Meters and Communication Network
(Millions of Nominal Dollars, Rounded)

Line No.	Description	O&M	Capital	Totals
1.	Outsourced Installations	0.0	121.2	121.2
2.	SCE Installations	79.6	95.8	175.4
3.	**Totals**	**79.6**	**216.9**	**296.6**

a) Cost Drivers for Outsourced Installations

The Outsourced Installations activity has one primary cost driver that is the cost per meter installed by the selected installation vendor(s). The scope of Outsourced Installations involves the installation of residential and small commercial meters and related communication network equipment. The deployment contract is largely based on a cost per meter successfully installed unit cost. This unit cost includes the vendor(s)'s overhead and other activities required to support the installations, such as temporary meter warehousing. Prior to mass meter installation, SCE will work with the selected vendor to prepare the necessary installation policies, safety procedures and systems required for mass meter deployment.

b) Cost Drivers for SCE Installations

The $175.4 million forecast in this category is comprised of $79.6 million in O&M expense and $95.8 million in capital expenditures. The capital expenditures comprise 56 percent of the total SCE Installations costs. There are four key activities that make up SCE Installations function. The single largest activity in this area is the meter installation; specifically, all the meter installations due to normal customer growth; the installation of A-base adapters in order to accommodate new Edison SmartConnect™ Meters, replacing existing meters with Edison SmartConnect™ meters where the outsourcing vendor was unable to complete the installation due to access or other issues, replacing existing meters with Edison SmartConnect™ meters for three phase self-contained and all CT rated services, and immediate supervision of the personnel who are installing meters, meter service hardware and software tools, replacement of meters that fail after installation, and increased costs of meter handling.

The second major capital cost driver is the program office management oversight of the installation activities. This includes costs for managing the installation vendor(s), including ongoing monitoring of the vendor(s) installation practices and monitoring the execution of SCE's installation plan. This activity also involves managing integration of installation activities between the vendor(s) and SCE resources such as supply chain management, meter field operations, customer call center, billing, and distribution field operations.

There is also a considerable amount of O&M expenditures that relate to SCE's field services resources that will support the Edison SmartConnect™ deployment. The Edison SmartConnect™ meter is substantially more sophisticated than the electromechanical meters that it will replace. As such, new technical skills are required to provide ongoing operations and maintenance as well as incremental staff to service the large fleet of meters after they are installed beginning in 2009. The estimated cost associated with SCE's incremental O&M associated with the Edison SmartConnect™ meter during deployment is approximately $79.6 million in O&M expenses. These costs include development and implementation of training for the individuals who will be installing Edison SmartConnect™ meters, increased travel time as the number of employees in the field are reduced, and increased detection of meter tampering and energy theft investigation activities by SCE during the meter installation process.

Currently, meter readers identify potential meter tampering while performing their regularly scheduled meter reading routes. As the Edison SmartConnect™ meters are deployed, contract installers will conduct a visual inspection to identify potential tampering and energy theft and through the tamper detection flag in the meter. Where it is determined that tampering and or energy theft may exist, a revenue protection investigator will be sent to the site to confirm and/or resolve any meter-related issues. For higher voltage three phase and all CT-rated services, the revenue protection investigators must be accompanied by a meter technician. The remote service switch will reduce the number orders that will be worked by Field Service Representatives (FSRs) in the field. This will result in a reduction of the number of FSRs performing the remaining work and increase the travel time between orders. This resulting increase in travel time requires a lesser reduction in FSRs in order to continue to perform the volume of work remaining.

In addition, the O&M expense includes the costs associated with the repair of meter panels damaged as a result of a meter installation. Many of SCE's existing meters were installed decades ago, and over time, the customer's meter panels have deteriorated. The advanced age of many of the meter panels as well as the fact that a significant population of meters are in coastal areas are expected to contribute to a percentage of deteriorated meter panels. As such, replacing these existing meters may require repair or replacement of the customer's meter panel resulting from damage which may occur during the meter change.

c) Expected Annual Expenditures for Installation of Meters and Communication Network Equipment

Table III-6 shows the annual expenditures for the Installation of Meters and Communication Network Equipment capital and O&M during the Deployment Period. As previously stated, SCE plans to reach full deployment levels in 2009 and complete deployment in 2012. A small portion of the total costs in this area will support the refinement of mass deployment related policies, procedures, processes, and systems related to Installation of Meters and Communications Network Equipment in 2008. Consistent with SCE's deployment schedule, the capital expenditures in the program area ramp up significantly in 2009 as the deployment gets underway.

Table III-6
Expected Annual Expenditures for Installation of Meters and Communication Network
(Millions of Nominal Dollars, Rounded)

Line No.	Description	2007	2008	2009	2010	2011	2012	Totals
1.	O&M	0.5	11.5	14.2	18.9	20.9	13.6	79.6
2.	Capital	0.0	3.5	52.3	62.2	64.1	34.9	216.9
3.	**Totals**	**0.5**	**15.0**	**66.5**	**81.1**	**85.0**	**48.5**	**296.6**

C. Implementation and Operation of New Back Office Systems

To understand the scope of the integration and implementation, it is necessary to understand the scale of the Edison SmartConnect™ system compared to how SCE operates today. Today, SCE receives 12 meter reads a year from typical residential customers. In the future, SCE will receive 24 hourly intervals each day for each customer with an Edison SmartConnect™ meter. After full deployment of the Edison SmartConnect™ meters, SCE will collect in excess of 120 million interval reads per day from SCE's customer base. This massive increase in data volume drives intense data processing and storage requirements needed to support the new meter capabilities and increased volume or reads. This translates into as many as 126 processors in 68 servers for the MDMS alone. While this reflects the majority of the infrastructure cost necessary to support Edison SmartConnect™ back-office, additional incremental infrastructure is required for integration with Network Management System as well as the load management system, billing systems, web portal and other SCE systems to support enhancements and integration between systems.

As part of the pre-deployment activities, the information systems effort includes the procurement, design, and initial development of the Meter Data Management System (MDMS). For deployment, the Edison SmartConnect™ information systems will access and process the data generated by the Edison SmartConnect™ meters and any in-home devices supporting future Edison SmartConnect™-enabled programs. To accomplish this, the information systems effort will include the development of the Network Management System, complete the development, integration and overall systems testing of new Edison SmartConnect™ systems begun during 2007, with existing SCE systems, as necessary, to provide a seamless operational transition of existing business processes to the new automated processes being introduced by Edison SmartConnect™. Additional new software and enhancements to existing systems will be required to fully develop the Edison SmartConnect™ functionality. The development cost estimates include the SCE resources and consulting support needed to complete the implementation of the new back office systems.

In addition, effectively operating the installed Edison SmartConnect™ system requires a team of qualified and dedicated personnel to manage the ongoing operation and maintenance of the new communications system and smart meters. SCE is planning to add incremental staff to manage and control the Edison SmartConnect™ system through effective processes and via the Network Management System software provided by the telecommunication network technology vendor and an AMI Network Operating Center. Network operations will monitor, control, manage, and respond to the system and its key operating system indicators. The operations functions will include:

- Balance meter data loading and other operational demands required of the Edison SmartConnect™ network to ensure high system performance and reliability;
- Develop metrics and provide regular system reports;
- Identify and resolve system performance issues;
- Manage meter and telecom network configuration including security and remote firmware upgrades; and
- Control user configuration and access.

1. Overview of the New Back Office Systems

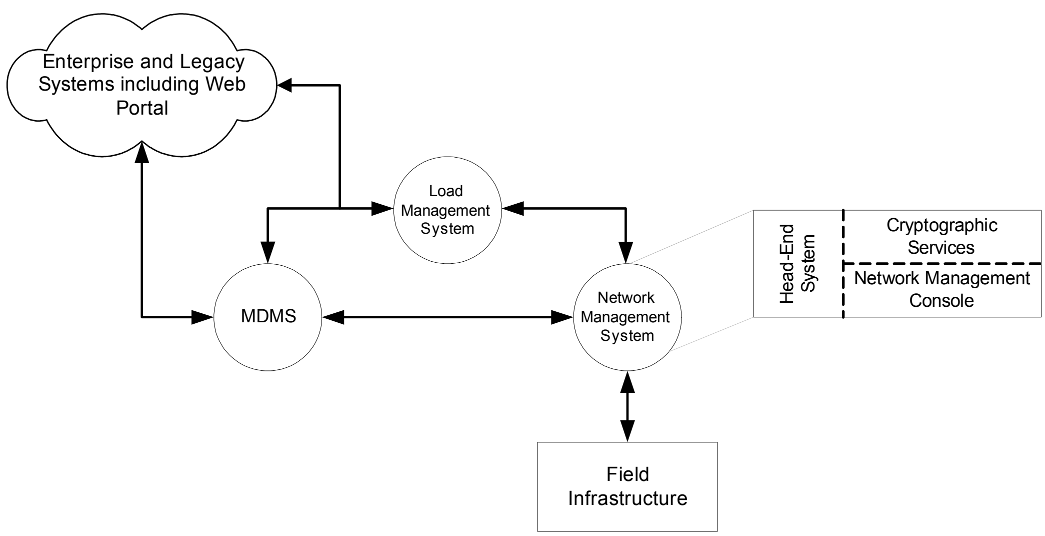
The Back Office Systems program area is responsible for managing all of the activities associated with identifying and designing the appropriate business process requirements for the Edison SmartConnect™ information technology needs and then designing, developing, procuring and implementing the resulting automation (hardware and software) that will be required to establish two-way system communications between meter at the customer's premise and SCE's back office systems (*e.g.,* SCE's legacy customer care systems, load control systems, outage management systems). Critical elements of the new back office systems include the design, development and deployment of the Network Management System, MDMS, load control systems, billing system enhancements, web portal development for energy information and program support, along with integration between these systems and other SCE's legacy systems such as outage management. Each of these areas is described in more detail in the sections that follow.

SCE determined that, in order to effectively manage the scope and complexity of the overall back office system integration and enhancements, the system development work would need to be conducted through multiple software development cycles or releases. As part of SCE's detailed planning for deployment, SCE identified three distinct releases for the systems development work associated with back office systems enhancements and integration. These releases are described in detail in Chapter II.C of this Exhibit.

2. New Systems and Enhancements

Figure III-5 below depicts the relationship between the Edison SmartConnect™ back office systems. The lines in between the systems represent integrations that transfer data and information between the systems that allow each system to operate and enables the Edison SmartConnect™ business processes. Each system and their required integrations are described below.

Figure III-5
Simplified Back Office Architecture



a) Network Management System

While the cost of the Network Management System software is not included in the back-office, the development and integration costs are included in the back-office scope of work. The Network Management System is the gateway to all Edison SmartConnect™ meters and field infrastructure. As such, all commands sent to and all data received from the Edison SmartConnect™ meters and network field infrastructure must pass through the Network Management System. The Network Management System includes three subcomponents: the head-end component to communicate with the meters; the network management console to optimize and manage the individual meters and network field infrastructure and how they work together; and the cryptographic services component to secure the data and communications of the entire network.

The Network Operations Center is a physical place that includes the systems and personnel to oversee the operations of the AMI telecommunications network. The Network Operations Center views information about the status of the network; any events or alarms sent by devices attached to the network; and the performance of the Edison SmartConnect™ network through the network management system. For example, network operators may use the Network Management System to optimize the performance of the network, perform and manage remote upgrades to network attached devices and determine the severity and appropriate response to events observed while monitoring network activity.

b) Meter Data Management System (MDMS)

The MDMS is the repository of the meter and event data from the Edison SmartConnect™ meters. In addition, the MDMS provides all of the validation, editing and estimating necessary to support customer usage calculation necessary to generate an accurate bill. As the system of record for meter data, other systems that require meter data from the Edison SmartConnect™ system will retrieve such data from the MDMS. This serves to insulate the rest of SCE's systems from the large volumes of data collected from the Edison SmartConnect™ meter population.

Aside from meter reading and billing support functions, the MDMS also receives and routes all messages from the meter population to the appropriate SCE systems. This includes the alarms for meter failures, power outage, tamper events, demand response messages, service switch operation and messages from associated HAN devices. The MDMS is able to generate work order requests and route them accordingly. As referenced below, the MDMS also prepares and provides the data for delivery to individual customers equipped with Edison SmartConnect™ meters; satisfies the reporting and data needs for SCE related to load forecasting, revenue and usage reporting, load control response, wholesale settlement usage aggregation, and usage data to support distribution planning and operations.

SCE selected eMeter's software platform, EnergyIP™, which has three major elements: 1) a MDMS that provides a meter data warehouse and processing such as Validation, Editing, and Estimation (VEE), 2) an integration platform for linking a variety of meter data collection systems to a variety of utility information systems, and 3) Business Process Management software specializing in advanced metering implementation, operations, and maintenance. EnergyIP extension applications enable interval data collection, complex billing, and Web presentment of detailed energy usage data.

c) Load Control Systems

The Load Control Systems are the management and control system to manage the smart thermostat and other new dispatchable load resources. These systems are required to support the new functionality offered by smart thermostats for grid reliability as well as for economic dispatch. The existing system used to manage SCE's Air Conditioning Cycling Program (ACCP) cannot support economic dispatch functionality or other more sophisticated demand response program features that are envisioned. SCE anticipates conducting a competitive RFP for a new load management system. The assumptions in this case are derived from the analysis completed during Phase I and Phase II as well as prior and recent efforts by SCE to assess advanced load control functionality and related systems requirements and cost estimates.

The new Edison SmartConnect™ meters have the capability to communicate with customer-owned devices through the HAN. For customers that sign up for demand response programs allowing SCE to control their devices (*i.e.,* thermostats, *etc*.), remotely during demand response events, the Load Control Systems are responsible for dispatching the commands through the Edison SmartConnect™ network to the devices that will ultimately respond. The communication is two-way enabling acknowledgement of receipt of demand response commands by the device as well as customer over-ride capabilities.

The Load Control Systems must be aware of the program in which the customer is enrolled, must have information on the device that will respond to demand response messages and must have the flexibility to organize customers into groups designed to optimize the response across the distribution network. As such, information about the customer, their participation in demand response programs and the configuration of their meters and devices must be received from the MDMS and Network Management System. Because the MDMS must be aware of demand response events, the Load Control Systems will send messages through the MDMS via the Network Management System to the meters. Acknowledgement, customer over-ride messages and usage measurements collected during the demand response event period shall similarly come back through the Network Management System to the MDMS and then the Load Control systems.

SCE proposes to enhance the existing Load Management System used to support SCE's existing ACCP demand response program. The existing system is a one-way system and must be enhanced to support Edison SmartConnect™ enabled demand response programs. Specifically, all the acknowledgement, device state (*i.e.,* is the device on or off, *etc.*), over-ride and device registration information must be provided to the Load Control Systems to be able to assess the demand response capacity available at any given time and enable effective grouping and management of customers on demand response programs.

d) Billing Systems

The MDMS calculates a customer's usage based on the program or the rate on which a customer takes service. In order to perform this task, the MDMS must have information about the customer, the meter and the program in which the customer is enrolled. Hence, an interface is required to synchronize the data between the MDMS and Billing systems. Once the MDMS calculates the customer's usage, the data will be sent to the Billing system for the bill calculation and generation process. Initially, the MDMS will integrate with SCE's current billing system. When the new SAP billing system replaces the existing legacy system, currently planned for 2009,[15] MDMS will be integrated with that system. Beyond basic billing functions, additional integration to enable on-demand, remote reading of Edison SmartConnect™ meters; operation of the individual customers' service switches; and meter asset management and installation support will be required.

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[15] In the event of changes to the SAP deployment, it may be necessary to alternatively enhance the existing systems to support the Edison SmartConnect™ functionality.

e) Web Portal

The web portal will provide each customer the opportunity to view their own usage data, collected by the Edison SmartConnect™ meters, through the internet via the sce.com website. In order to accomplish this task, the MDMS system will process and send the customer's data to a web portal for access to their meter data. The system may require some analytical preparation of the data so the customer can use it as well as integration with web portal so the data may be displayed on a web page at *sce.com*. The connection is secure so that customers only may view their own personalized data. The implementation of this capability will span Release 1 and 2. In Release 1, it is envisioned that the population of customers that have Edison SmartConnect™ meter will be able to view basic meter read data via the web portal. Release 2 would include more robust functionality including sophisticated analytics that would relate the usage data to the customer's program and bill. In subsequent releases during deployment, SCE expects to further develop the customer portal with features that support personalization and simplification of choice related to programs and services available.

3. Integration

The following describes the scope for integrating the Network Management System, MDMS, and back office systems.

a) Integrating Network Management System and MDMS

The MDMS integrates with Network Management System to facilitate two way communications between the meter at each customer's premise with our MDMS and billing systems. The first step in integrating the Network Management System with the MDMS is to identify business processes that are changed or enabled through the implementation of Edison SmartConnect™. These business processes are designed and then analyzed to identify the data and commands necessary to enable the new or changed business process. Individual interfaces are designed and developed to enable the flow of data between these two systems. The volume of the data and frequency with which each interface must run determines the software and hardware design and sizing necessary to support the integration between the Network Management System and MDMS. The resulting infrastructure and integration development activities are the primary cost drivers in the implementation and operation of each system.

b) Integrating MDMS with Billing Systems

The MDMS integrates with the billing system to pass VEE usage data to the billing system for the issuance of customer bills. Once the MDMS calculates the customer's usage, the data will be sent to the Billing system for the bill calculation and generation process. Initially, the MDMS will integrate with SCE's current billing system. When the new SAP billing system replaces the existing legacy system, currently planned for third quarter 2009, MDMS will be integrated with that system.

c) Integrating MDMS with Web Portal

The MDMS integrates with web portal to provide interval usage data for each customer via the Internet. In order to accomplish this task, the MDMS system will process and send the customer's data to a web portal to provide customer to access their meter data.

d) Integrating MDMS with Outage Management System

Integration between the MDMS and Outage Management System to support Edison SmartConnect™ enables outage reporting and management processes. Outage messages will be received through the Network Management System to the MDMS and passed to the Outage Management System. The Outage Management System associates the meter with the distribution asset relative to the particular meter. The hierarchy of relationships between distribution network assets (*i.e.,* transformers) will be extended from the network bus currently in Outage Management System all the way to the customer premise level. This will allow the Outage Management System to rapidly correlate outage messages, received from Edison SmartConnect™ meters via MDMS to rapidly pinpoint where the failure in the distribution network has occurred. In addition, the Outage Management System will send planned outage information to the MDMS so that outage message volumes may be filtered and managed across the Edison SmartConnect™ network. In the future, bringing together information gathered from the Edison SmartConnect™ meter population about outage management together with distribution automation data may provide the foundation for more advanced "Intelligent Grid" applications.

e) Integrating MDMS with Other Systems

In addition to the integration activities described above, other SCE systems will require integration with the MDMS. These systems include the following:

- MDMS to revenue protection systems for optimized tamper detection processes. The Edison SmartConnect™ meters have the ability to send tamper event messages to the MDMS which will then be passed onto the revenue protection systems.
- After integration of the MDMS with Power Procurement Systems, the MDMS will pass interval data sample sets to load forecasting systems to support more accurate energy forecasting in support of Power Procurement processes.
- The capability to perform contract meter reading (gas/water meter reads via Edison SmartConnect™) is possible. Should SCE provide contract meter reading to another utility company, either the Network Management System or the MDMS may need to integrate with the other utility company's billing systems.
- The Edison SmartConnect™ meters will have the capability to interface with meters for plug-in hybrids through the HAN communication interface which might allow for design of special plug-in hybrid programs. The MDMS would need to be aware of the program the customer is participating in and the customer's vehicle information. This would require some additional enhancements to the MDMS and surrounding interfaces.

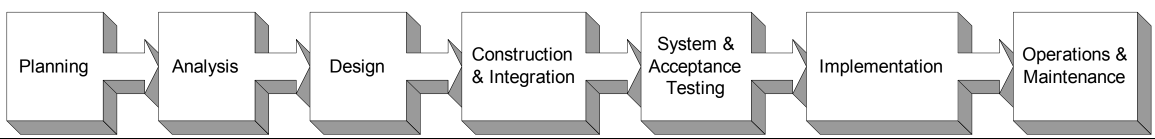
f) Integrating MDMS with Load Control Systems

The Load Control systems are designed to support Edison SmartConnect™ enabled demand response programs across SCE's control area. As such, the MDMS must be aware of those customers who are on demand response rates, which demand response program each customer is enrolled in, and when a demand response event has occurred. This will allow the MDMS to calculate the customer's usage and monitor their response to the event accordingly. In turn, the billing system, through the integration described above will receive the information necessary to accurately bill the customer according to the terms of the appropriate demand response program.

4. Development Method

The vast majority of the functions in the three releases are the result of software systems development. In order to successfully manage all of the activities associated with the three releases, SCE is using the highly successful System Development Life Cycle (SDLC) process. This is a standard and widely accepted software development process that is used to develop information systems by establishing business requirements, validations, training and user ownership. The SDLC model is shown in the figure below, which illustrates the entire development path from planning up through implementation and operations and maintenance.

Figure III-6
Software Development Life Cycle



Each of the key elements of the SDLC model is briefly described below:

- **Planning** – Establishes the business requirements and needs of the COTS software in accordance with Edison SmartConnect™'s functionality. The planning phase of the SDLC will:

  Define the functional business requirements;
  Identify the project's scope;
  Develop the project plan; and
  Manage and monitor the project plan.

- **Analysis** – A collaborative effort between the functional users and IT specialists to collect, comprehend, and logistically formalize business requirements. The analysis phase of the SDLC entails:

Gathering the business requirements;

Analyzing the business requirements; and

Prioritizing the business requirements;

Identifying architecture elements in the solution; and

Mapping requirements to architecture elements (systems, subsystems & components).

- **Design** – Creation of the technical blueprint. The design phase of the SDLC includes:

  Defining or designing the Edison SmartConnect™ architecture and how it fits within SCE's enterprise architecture; and

  Designing the new back office systems model such as specifying graphical user interfaces, systems integration, screen designs, reports, databases and physical infrastructure.

- **Construction and Integration** – Execute the design into a physical system. This is achieved by:

  Procuring the COTS packages; and

  Integrating systems with each other, installing software on hardware within the data center,

  Developing any enhancements or software necessary

- **System and Acceptance Testing** – Test the developed system to determine the new back office system's functionality as planned and designed. Testing occurs in a separate, parallel environment which allows programmers to write conditions and test it before placing it into the live environment. Testing allows programmers to identify bugs and make any changes prior to implementation.

- **Implementation** – After system and acceptance test the system is placed into production and operated by the appropriate end-users. End-user training is conducted and the system is stabilized through a higher support level to resolve any issues in the first several weeks after "go-live."

- **Operations and Maintenance** – Once the new back office system is implemented, IT will be responsible for maintaining the system by keeping it up to date with any changes and ensuring the new back office system meets corporate goals. IT will achieve this augmenting its help desk to support the system users and implementing changes when necessary.

SCE recognizes that the implementation of Edison SmartConnect™ will introduce a significant change to both employees and customers. This change must be managed and planned well in advance of the first meter implementation and throughout the lifecycle of Edison SmartConnect™'s deployment. Successfully managing this change will minimize business disruption, enhance productivity, and accelerate the value of the Edison SmartConnect™ project.

5. Management of the Back Office Systems

To ensure successful development and implementation of back office systems, structured project management oversight and governance will be utilized. Processes and tools will be put in place to manage scope, schedule, budget, and resources consistent with the Project Management Institute's Project Management Body of Knowledge. Appropriate governance will also be put in place to manage issues identification, escalation, and resolution.

Additionally, SCE personnel must be prepared through training and education to operate and utilize the new systems during the Deployment Period.

6. Back Office Systems Risk Mitigation

There are various uncertainties and risks that may affect the integration and enhancements of the Network Management System and the MDMS and the billing legacy system, load management legacy system and other SCE legacy systems. SCE analyzed these risks including vendor and the integration and enhancements of the SCE legacy systems. Given the level of risk, it is appropriate to include a contingency in the Edison SmartConnect™ project cost estimates based on SCE's prior experience in software development integration and systems enhancement. The program's contingency estimate is further discussed in Chapter IV. Examples of risks and mitigation measures include:

a) Vendor Risk

SCE, in part, managed vendor risk by selecting a firm that has the capability, financial standing and proven track record to support their technological expertise. SCE has selected eMeter as the MDMS vendor due to: a) the application functionality, b) performance results in scale testing conducted by IBM, at SCE's direction, in their New York labs, c) direct and relevant experience implementing their MDMS software for large scale utility AMI systems. Since 1999, eMeter Corporation of Redwood City, California, has provided software and services for electric, gas, and water utilities with fixed network AMR systems. eMeter is one of the leading MDMS vendors with five existing North American clients with AMI systems representing over 11 million smart meters (not including SCE) as well as direct experience in the California market including the Statewide Pricing Pilot. SCE has also engaged eMeter under contract terms and conditions that align eMeter's commercial interests to those of SCE and its customers to help mitigate implementation risk.

b) Development and Integration Risk

The integration of the network management system and the MDMS to the billing and other SCE legacy systems is highly complex and relies on the successful interaction of the required hardware and the necessary software to allow the systems to properly function. A risk exists that the integration between the systems or one or more of the legacy system enhancements may fail leading to a substantial loss of functionality. SCE is managing development risk by employing a multi-release approach to build foundational capabilities in Release 1 and then in subsequent releases add more sophisticated functionality so as to ensure successful deployment of each release before embarking on more complex functionality. SCE is also employing the software development lifecycle model that relies heavily on the planning, analysis, design and system acceptance testing elements to develop software that will integrate with several systems including SCE's billing system. In particular, SCE relies on the testing element of the SDLC to mitigate potential risk. This testing is realized in the form of individual unit testing (*e.g.* testing of individual system components or hardware), system acceptance testing (*e.g.* full system testing) and continuous acceptance testing (testing as the full system scales up). Each of the three releases utilizes the SDLC method to manage the development process. The combination of multi-phase functional releases and the rigor of the SDLC process help to mitigate the risk for a large complex AMI system.

SCE also engaged an experienced system integrator to manage the development and integration of the network management system and MDMS. The purpose of the system integrator is to augment SCE's information systems professionals with a team of consultants with direct and relevant experience with AMI system development and complex system architecture. SCE selected IBM as the system integrator in mid-2006. IBM's consulting services group has current experience at several large AMI deployments representing over 25 million meters in North America including PG&E, Centerpoint, IESO (Ontario ISO) and SCE. The lessons learned and best practices brought to the team by IBM have been very valuable and continues to be a key resource for mitigating program risks.

Additionally, SCE employed favorable contract terms with its vendors to align interests, deliverables, and risk sharing among the parties so that SCE and its customers can realize the benefits of these systems.

7. Estimated Costs for Implementation and Operation of New Back Office Systems

Table III-7 shows the estimated O&M and capital costs during the Deployment Period needed to implement and operate the new back office systems during the Deployment Period. These estimated costs are comprised of four key functions: MDMS and integration with the Network Management System; Back Office Enhancements; Load Control Systems; and Network Management System integration deployment costs incurred in 2007. As shown in Table III-7, the MDMS development and MDMS to Network Management System integration activities comprise about 54 percent of the total costs. About 72 percent of the estimated costs for the back office system upgrades are capital expenditures to implement the changes to SCE's existing information technology infrastructure and processes required to support Edison SmartConnect™. Within each of the three parts, the costs drivers are primarily software licenses, hardware, and system integration (programming) activities in addition to the labor required to for the initial implementation and ongoing operation. More detailed discussion is provided in subsequent portions of this section.

Table III-7
Estimated Costs for Implementation of New Back Office Systems
(Millions of Nominal Dollars, Rounded)

Line No.	Description	O&M	Capital	Totals
1.	MDMS and Network Management System	21.7	90.7	112.4
2.	Back Office Enhancements	19.7	51.7	71.4
3.	Load Control Systems	0.0	7.4	7.4
4.	**Totals**	**41.4**	**149.8**	**191.2**

a) Cost Drivers for MDMS and Network Management System

The $112.4 million forecast for this function is comprised of $21.7 million in O&M expense and $90.7 million in capital expenditure. The single largest activity in terms of cost is the integration of the Network Management System with the MDMS. As discussed earlier, because the Network Management System is bundled with the communication network equipment, the acquisition of the Network Management System software license is considered a part of the Acquisition of Meters and Communication Network Equipment program area. However, the integration costs of the Network Management System with the MDMS as well as the management of customer usage data are included in the Back Office Systems program area. The forecast capital expenditure includes the servers and disk space required for processing and storing 13 months of customer interval data. Because the Edison SmartConnect™ meter will collect hourly interval data from the customer, the Edison SmartConnect™ system will collect 120 million reads per day from the new meters. This is a major driver of infrastructure costs. For example, the back-office infrastructure required to support the MDMS alone may require in excess of 10 Terabytes of disk space. Additionally, this increase in customer data and infrastructure is implemented through labor required to install and integrate the MDMS infrastructure and the software that runs on it as well as the software and infrastructure supporting the MDMS integration with the Network Management System. The forecast O&M costs include both the labor to maintain the MDMS system itself as well as the maintenance labor to support system integration programming between the network management system and the MDMS.

b) Cost Drivers for Back Office Enhancements

Back office enhancements forecast costs are comprised of $51.7 million in capital expenditure and $19.7 million in O&M expenses. The following describes the activities required to integrate the MDMS with the different back office systems.

(1) Integrating MDMS with Billing Systems

SCE will integrate MDMS with the existing billing system in Release 1 in 2008 to support the start of full deployment in 2009. This activity includes implementing interfaces between MDMS and the billing systems as well as changes to the billing systems themselves necessary to generate accurate bills for customers with Edison SmartConnect™ meters; provide access to Edison SmartConnect™ related data to users (such as call center or customer contact employees) across SCE; enroll and manage customers in new Edison SmartConnect™ enabled programs; operate the service switch; perform on-demand, remote meter reading; and manage meter asset and installation processes.

SCE is currently deploying an Enterprise Resource Planning (ERP) system using SAP, a large enterprise application, with plans to replace financial, procurement, and other SCE organizations' back office systems during 2008-2009 and existing billing system in the third quarter of 2009. Edison SmartConnect™ plans to integrate with the SAP billing system with Release 2 in the third quarter of 2009. SCE plans to reduce significant program risks associated with concurrent development of both systems and full scale deployment of meters through integrated process designs and a mitigation strategy that involves maintaining the legacy billing system for an additional six months. This approach mitigates significant systems development risks and avoid disruption to SCE's deployment schedule. However, this mitigation strategy adds software development and maintenance expense for the legacy system and SAP system design and development complexity for the additional six months.

(2) Integrating MDMS with Web Portal

This activity relates to the integration of the MDMS with the Web Portal and enhancements to *sce.com* to provide customers access to data from their Edison SmartConnect™ meter through the internet via a web page on *sce.com*. The forecast capital expenditures include the development and implementation labor to support Web Portal software enhancements; additional hardware to support increased customer usage of *sce.com*; software and hardware to support MDMS analytical data preparation (*i.e.,* present the data to the customer in the context of the program they are enrolled in); and integration between the MDMS and the Web Portal. The forecast O&M expenses include labor necessary to maintain software and hardware for integration and within the MDMS and Web Portal to provide customers access to their meter data on-line.

(3) Integrating MDMS with Other Systems

This activity involves the activities necessary to integrate the MDMS with other SCE systems during Release 3 such as the outage management system. This function involves several activities. The first includes labor associated with integration, software enhancement and maintenance activities to support Edison SmartConnect™ enabled outage reporting and management processes. The second major activity in this function is labor associated with integration and software enhancement activities to support MDMS to revenue protection systems integration to optimize tamper detection processes. The third major activity in this function is integration and software enhancement activities needed to support more accurate energy forecasting for Power Procurement processes.

(4) End-to-end testing of New Back Office Systems

This function involves the end-to-end testing of SCE's new back office infrastructure and is an O&M expense. In includes labor to design and run the end-to-end tests to ensure Edison SmartConnect™ business process are supported and the systems and integrations developed during a particular release are ready for production operation.

c) Cost Drivers for Load Control Systems

The $7.4 million in forecasted costs for this function is capital expenditure. These costs reflect significant upgrades to SCE's existing load control systems in addition to integrating the ability to remotely control the advanced meters through the MDMS. These changes will require redesign and implementation of load control processes and training for the load control operators. In addition, these costs include the maintenance of the new load control system during the Deployment Period.

d) Expected Annual Expenditures for Implementation of New Back Office Systems

Table III-8 shows the expected annual expenditures for the Implementation of New Back Office Systems by capital and O&M during the Deployment Period. The higher costs reflected in 2008 and 2009 reflect the higher amount of work required to prepare the back office systems for mass meter deployment scheduled to begin in 2009. The remaining years reflect the expansion of the implemented new systems required to accommodate the growth Edison SmartConnect™ program as meters are deployed as well as integration of the MDMS with SCE's new customer interface systems in 2009 and 2010.

Table III-8
Expected Annual Expenditures for Implementation of New Back Office Systems
(Millions of Nominal Dollars, Rounded)

Description	2007	2008	2009	2010	2011	2012	Totals
O&M	0.9	3.5	10.5	12.3	6.9	7.3	41.4
Capital	6.7	55.4	33.9	30.4	15.0	8.4	149.8
Totals	**7.5**	**58.9**	**44.4**	**42.7**	**21.9**	**15.7**	**191.2**

D. Customer Tariffs, Programs and Services

An essential part of SCE's advanced metering program implementation is the establishment of tariffs and programs that enable customers to benefit from Edison SmartConnect™. SCE's business case places a high priority on providing the means for customers to limit their electrical consumption during high-cost, on-peak periods and to take full advantage of lower off-peak pricing and direct load control incentives. This results not only in reduced customer energy costs, but also accounts for a major element of SCE's long-term cost reductions associated with avoided capacity and energy costs.

The objectives of the Customer Tariffs, Programs and Services function are to develop and implement the tariffs, programs and services during the Deployment Period to enable customers to benefit from the capabilities of Edison SmartConnect™. In addition, this section addresses the expected impacts to customer service operations required to support and externally communicate the deployment activities and delivery of the new tariffs, programs and services.

Exhibit SCE-4 provides a detailed discussion of the various tariffs and programs that SCE plans to offer as a result of Edison SmartConnect™. The related development work began nearly five years ago and utilizes the Statewide Pricing Pilot (SPP) conducted in 2003 and 2004 to determine the price responsiveness of customers that would be enabled through an advanced metering program. SCE then followed a three-phase approach for deploying Edison SmartConnect™ and conducted customer tariff and program development activities. During Phase I, use cases identified potential customer programs or uses for the advanced meters. Ongoing work during pre-deployment includes design of the technical and business requirements for supporting the new tariffs and programs. As stated in Exhibit SCE-1, SCE is seeking authorization to implement a Programmable Communicating Thermostat (PCT) load control programs, and re-activate the CPP rate(s) used for the SPP in this application. SCE plans to seek rate design authorization for other demand response programs and new dynamic rates in its 2009 GRC Phase II filing.

1. Summary Descriptions of the Customer Tariffs, Programs and Services

Much of the work in this area will involve outreach to the customers to educate them on the new rates, programs and services enabled by Edison SmartConnect™ and how these offerings can help customers control their consumption, lower their on-peak usage and save on their electricity bills. In short, Customer Tariffs, Programs and Services includes dynamic rates and demand response programs. The following discussion summarizes the proposed programs which are furthered detailed in Exhibit SCE-4 supporting this Application.

a) Demand Response

(1) Load Control

Load control programs provide significant peak load reductions and power procurement benefits. An essential part of SCE's approach to load control is a PCT compatible with the anticipated Title 24 building code standard under development by the California Energy Commission (CEC) for implementation in 2009.

During deployment, SCE will continue to work with the CEC and other utilities to develop the PCT technology that is compatible with Title 24 and Edison SmartConnect™. SCE envisions leveraging the Title 24 PCTs installed by customers, as well as, providing customer rebates (up to $125) for the purchase, installation of the Title 24 compliant PCTs and enrollment in an

SCE PCT program in lieu of air conditioning compressor switches used for the current Summer Discount Plan (SDP). SCE will continue to work with thermostat vendors and other parties to accelerate the design and testing of affordable PCTs. SCE will also examine potential tariff designs and system requirements to enable pay-for-performance (such as by reduction event) rather than seasonal incentive payments.

SCE requests that the Commission approve the PCT load control program summarized in this section and detailed in Exhibit SCE-4 so that SCE may implement the associated programs to support Title 24 in a timely manner.

(2) Peak Time Rebate

In its 2009 GRC Phase II application, SCE will request authority to implement a PTR program for all residential customers. SCE's proposed PTR program is similar to the program approved by the Commission for SDG&E's AMI deployment.[16] The PTR will be an "overlay" to the existing dynamic rates, TOU, or tiered rates, compatible with AB-1X, and will provide for credits for usage reductions during peak periods of PTR event days.

Under the PTR program, all residential customers with an Edison SmartConnect™ meter will automatically be eligible to participate in each PTR event. SCE may call up to 15 PTR events per year during the peak hours of 2 p.m. to 6 p.m., excluding weekends and holidays. Residential customers will be notified of a day-ahead PTR event through multiple channels which may include public service announcements, partnerships with "Flex Your Power" notifications, welcome greeting through SCE's call center and personal voice and text messages for those customers who request it. SCE assumes a PTR incentive of $0.66/kWh for reducing electricity usage during a PTR event.[17] There is no penalty for not reducing usage during a PTR event. SCE provides a more detailed discussion of the PTR program in Exhibit SCE-4.

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[16] *See* D.07-04-043.

[17] SCE plans to request approval of the PTR program and incentives in Phase II of its 2009 GRC.

SCE plans to begin offering PTR to residential customers in the fall of 2009, subject to GRC Phase II approval, as meters are installed. In this Application, SCE is seeking recovery of estimated incremental costs associated with PTR implementation during the Deployment Period. SCE expects to incur incremental costs during the Deployment Period to market and outreach to customers and educate them on the PTR program, and to administer the program.

(3) Dynamic Rates

TOU and CPP rates and the PTR program will provide significant peak load reductions. SCE has existing opt-in TOU and CPP rates for residential and Commercial and Industrial (C&I) customers under 200 kW. TOU and CPP rates will be offered to all residential and small commercial customer 0-19kW as their advanced meters are installed starting in 2009. Commercial customers with load 20-200kW will be defaulted to a new TOU, but may opt-out. Once the PTR program is authorized in SCE's 2009 GRC Phase II, residential customers will be automatically placed on the PTR program once they receive their Edison SmartConnect™ meter. SCE provides a more detailed discussion of these dynamic rates in Exhibit SCE-4.

SCE does not request approval of these modified rates in this application. Pending a decision approving the modified rates in Phase II of the 2009 GRC (expected in October 2009), SCE plans to offer its existing, voluntary TOU and CPP rates to residential and C&I customers under 200 kW as Edison SmartConnect™ meters are rolled out in 2009.

SCE does seek recovery in this application of the estimated incremental costs associated with the TOU and CPP rate offerings for residential and C&I customers under 200 kW during the Deployment Period. SCE estimates that it will incur incremental costs during the Deployment Period to market and outreach to customers and educate them about the existing and modified and new dynamic rates. SCE also expects to incur incremental administration costs associated with the dynamic rate offerings for residential and C&I customers under 200 kW during the Deployment Period.

2. Demand Response Program Development and Administration

Administration of new demand response programs enabled by Edison SmartConnect™ will involve program management activities related to development and implementation, customer enrollment, peak period customer notification, reporting and analyzing program results, and the processing of customer rebates and incentives. Each of these activities is discussed in the following sections.

a) Development and Implementation New Demand Response Programs

The development and implementation of a new price response or load control program is the responsibility of a program management organization charged with the development of a project plan specifying the schedule and scope of each program. Most new demand response programs require the collaborative efforts of a program design team made up of program management, market research, rate design, regulatory and legal resources, all dedicated to each of the individual programs as they evolve. This effort also includes coordination of program requirements with operational areas including Billing, Call Center and IT. The program development phase includes obtaining regulatory authorization for any related tariffs and or rule changes to accommodate each proposed program.

b) Customer Enrollment

As discussed in Section III.D.3 below, the customer enrollment phase usually includes the use of marketing resources to implement the appropriate level and mix of mass media and direct marketing to encourage optimum levels of enrollment of the targeted customer population. Administrative activities include monitoring program status, customer participation rates and the performance of support organizations.

c) Customer Notifications

As discussed in Section III.D.3.c below, several of the new Edison SmartConnect™ enabled programs will require direct notification of participating customers when critical peak periods are anticipated. For example SCE's proposed PTR program requires that participating customers be notified of a PTR event a day-ahead through multiple channels. CPP rates have similar customer notification requirements.

d) Reporting and Analyzing New Programs

Analyzing and reporting results of SCE's new programs are essential components of optimizing the value of SCE's demand Response Portfolio of programs and services. Monitoring customer attitudes and response to each individual program by conducting direct market research among participants and combining those results with actual metered data response obtained through the Edison SmartConnect™ system will provide a definitive assessment of each programs success or failure.

e) Processing Rebates and Rate Incentives

Assuring proper application of customer rebates and incentives is critical to the success of any program. The processes and systems needed to validate that all incentives are properly applied in a timely manner is an essential part of Program Management oversight.

3. Outreach and Marketing Communications

Helping customers make informed decisions that will benefit them and create the adoption of new tariffs, programs and services that support public policies is a key objective of Edison SmartConnect™. SCE operates in a very unique market place. Not only are there over 40 languages spoken in Southern California, but SCE operates in the second most expensive media market in the nation. Covering 50,000 square miles of territory populated by 13 million diverse residents naturally requires the use of multiple media channels and multiple sources within each channel.

a) Market Segmentation and Targeted Bundles

Not only are SCE's customers demographically diverse, but they also exhibit different attitudes toward electricity. As a result of its research, SCE currently segments its residential market into six personas. Each of these personas possesses unique traits in regards to their attitude towards energy, how they like to conduct business with SCE, and lifestyles. SCE plans to continuously monitor the effectiveness of its market segmentation and adjust the dividing lines as necessary over time.

Overall, SCE's marketing strategy is to provide simple and widely available communications containing intuitive and easy to understand information about the new tariffs, programs and services. These outreach efforts will be complemented with simplified enrollment procedures that are easy to use by customers. The initial stage of marketing new tariffs, programs and services will target customer groups based on the meter installation plan. Beginning in 2009, concurrent with the initiation of meter installations, SCE plans to undertake a significant and sustained marketing and outreach campaign regarding the new rates, programs, services available to customers as they receive their new meters. Throughout the Deployment Period and thereafter, SCE plans to continuously monitor customer behavior and adjust its marketing tactics as necessary to continue meeting public policy objectives and accommodate changing customer behaviors over time.

SCE will use the customer personas to design specific bundles of offerings to help drive adoption of the new tariffs, programs and services. Anchored by the appropriate Edison SmartConnect™ enabled rate(s), each bundle will be deliberately designed to help a specific customer group manage and conserve energy. During the Deployment Period, each customer will receive an Edison SmartConnect™ welcome package. This package will provide customers information about the various rates, load control programs, and services available to them as a result of receiving a new meter. The package will include a variety of materials such as fact sheets.

In addition to the initial outreach, SCE plans to provide ongoing communication to retain or expand customer participation. During and after the Deployment Period, SCE plans to a) modify its outreach and marketing campaigns to expand participation and b) provide the services required to retain customers. SCE will also develop services and tools for customers to manage their energy usage. Similar to the tools currently available to its large business customers, SCE plans to offer tools, mostly through the Internet, to residential and small/medium business customers that provide the level of information and functionality customers need to manage their usage and make decisions.

b) <u>Provisioning Customer Information and Home Area Network</u>

One of the six functional criterion specified by the Commission[18] for advanced metering is the availability of customer information as it is an important enabler of demand response. Access to electricity usage and cost information on a daily basis empowers customers to understand

[18] The six functional criterion specified by the Commission in R.02-06-001 are addressed in Section III.E of Exhibit SCE-1 of the testimony supporting this application.

their costs by time of day and by usage behaviors. Customer information generally improves response to demand response tariffs and programs and encourages energy conservation. Edison SmartConnect™ enabled tariffs and programs will be an important component of SCE's customer web portal, where customers will have access to information and have the ability to execute a wide range of inquiries and transactions. Customer access to energy information is one of the core tenets of Edison SmartConnect™ and with about 25 percent of SCE's customers without internet access, this HAN interface and some type of in-home energy display which will enable all customers to access to their usage which will empower them to make smart choices. The HAN interface capability has been incorporated into the leading vendors products based on market demand. For example, the Texas Public Utilities Commission incorporated the HAN interface into its smart meter rules. Smart meters with this capability are being deployed as part of SCE's Field Tests, as well as in Texas, Canada, Australia and other parts of the world.

c) Marketing and Customer Education Strategy

During the installation phase, SCE expects to notify customers of planned meter changes through direct mailings. Any mass media or other outbound communications that the Commission may direct SCE to use for purposes of public notification during the installation phase would add incrementally to SCE's estimated costs.

Beginning in 2009, concurrent with the initiation of Edison SmartConnect™ meter installations, SCE plans to undertake a significant and sustained marketing and outreach campaign regarding the new rates, programs, services available to customers as they receive their new meters. The strategic approach of the campaign is to use an integrated mix of media designed to maximize the customer opt-in for dynamic rate options and customer participation in demand response programs, retain customers on the TOU and/or CPP rates over time, and affect a long-term cultural and behavioral change for the purpose of maximizing demand reduction from all customers. The campaign must be multi-year in order to positively affect long-term change.

(1) Campaign Overview

Given the scope of the Edison SmartConnect™ effort, SCE needs to develop and implement an integrated, multi-layered, multi-year campaign that will explore new approaches for communicating relevant information on multiple, complex programs, in a manner that will help customers understand and enroll into the programs. The campaign will leverage existing efforts, as well as new opportunities. The primary marketing vehicles will be:

- Mass media will be used to generate awareness of the Peak Time Rebate (PTR). Since customers are automatically enrolled in this program, mass media will serve as an effective mechanism to reach SCE's diverse customer base with information about the program.
- Direct customer communications will be utilized throughout the life of the program. SCE expects to develop and implement a comprehensive enrollment and educational campaign to persuade customers to take advantage of new rates and programs and then help them modify behavior to maximize their demand reduction. SCE also plans to develop and implement a direct-communications retention campaign to maintain the customer base over time.

(2) Communications Media

During the course of the campaign, the weight and mix of media and direct communications as well as the overall cost will change to reflect the communications support required. To make outreach as effective as possible, SCE conducted research with SCE's customers to help us understand consumer attitudes and adapt messaging appropriately. Using this research, SCE developed an on-going campaign that includes communication and outreach that is designed to optimize the messaging to SCE's diverse customer base. SCE intends to saturate the customer base with a broad-based awareness and educational campaign, as well as specifics on how customers can respond to time-differentiated rates. The media mix SCE envisions for the campaign includes mass media, targeted/ethnic media, direct communications, and PTR and CPP event notification.

(a) Mass Media

Use of mass media will extend to cable television, print and online advertising to support general and event awareness to residential customers for the PTR program. For example, for the general English-speaking market, SCE envisions that cable television, print, and online advertising would run over a 3 to 4 month period of time, during the summer, when PTR events are likely to occur.

(b) Targeted/Ethnic Media

Use of ethnic media will extend to print, radio, and online advertising. Such targeted media channels will also leverage strategic partnerships (ethnic business chamber promotion) to reach SCE's diverse customer base. In-language media will emphasize education and awareness of the Peak Time Rebate program for eligible residential customers. For example, SCE envisions radio, and printed information to run on approximately the same time schedule as the general (English) market. The ethnic media will target Hispanic, Asian (Chinese, Korean, Vietnamese), and African American customers.

(c) Direct Communications

Use of direct communications will include bill inserts, direct mail, e-mail notification, voice mail notification, shared mail, newsletters, and face-to-face communication through outreach events and the account management function. Direct communications will be used throughout the entire life-cycle of the effort to communicate with customers. Messages will range from generating awareness, education and participation to retention. For example, messages used for retention and behavior change education are expected to help customers maximize demand reduction. Specifically, SCE envisions utilizing a variety of direct customer communication tactics staged over a designated period of time to maximize reaching SCE's customers and the frequency with which they hear SCE's education and retention messages, thus, driving behavior change.

(d) PTR Event Notification

SCE expects to notify customers of a PTR event through multiple channels which may include public service announcements, partnerships with "Flex Your Power" notifications, welcome greeting through SCE's call center and personal voice and text messages for those customers who request it.

(e) CPP Event Notification

SCE expects to use an automated phone messaging system to send voice and text messages and potentially press releases/press relations to notify customers of CPP days.

d) Campaign Goals and Objectives

The Edison SmartConnect™ media campaign will differ significantly from those previously undertaken by SCE. Previous campaigns were designed to create customer awareness and promote programs on a short-term basis. This campaign will use educational information and tools to help customers make the behavioral changes required to take advantage of dynamic rates and demand response programs. The purpose of this campaign is to maximize demand reduction from participating customers, as well as create retention information designed to retain customers on these rates over time. Long-term customer enrollment and long-term behavioral and cultural change are essential to Edison SmartConnect™'s success. One of the two main objectives of the campaign is to teach customers about why dynamic rates require behavioral changes and move them toward such behavioral changes. Through education, SCE expects to achieve customer understanding of their energy usage and offer them information and tools to manage their usage under these pricing options. This will be achieved through the customer-specific education portions of the campaign. The campaign's other main objective is to maximize the customer opt-in rate and retain customers on the dynamic rates over time. This will be accomplished through the customer-specific retention portion of the campaign.

The cost of this type of campaign is significantly affected by SCE's unique Southern California location as it relates to mass and in-language media costs (PTR program awareness only). Our service territory sits in some of the most expensive advertising costs/media outlets in the United States. The greater Los Angeles area, including Climatic Zone 4 communities, is the second largest and highest cost media market in the country. It is also both linguistically and culturally diverse.[19] As such, messages must be created and delivered in languages other than English. Additionally, 35 percent of SCE's customer base has demonstrated a lack of interest in electricity issues other than when their power goes out.[20] 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 various Asian, Spanish-speaking, and African-American communities, 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 close in comparison to media and advertising costs for other utilities (such as telecommunications utilities) in the Los Angeles Designated Market Area.[21]

e) Program Development Life Cycle

Designing effective marketing campaigns for such a diverse customer base requires extensive market research, analysis and planning. Combining the company's experience with industry best practices, SCE employs a proven approach for developing customer products and services. As shown below, developing and managing new programs and services can be divided into two periods -- New Program Development (NPD) and Ongoing Program Management (OPM).

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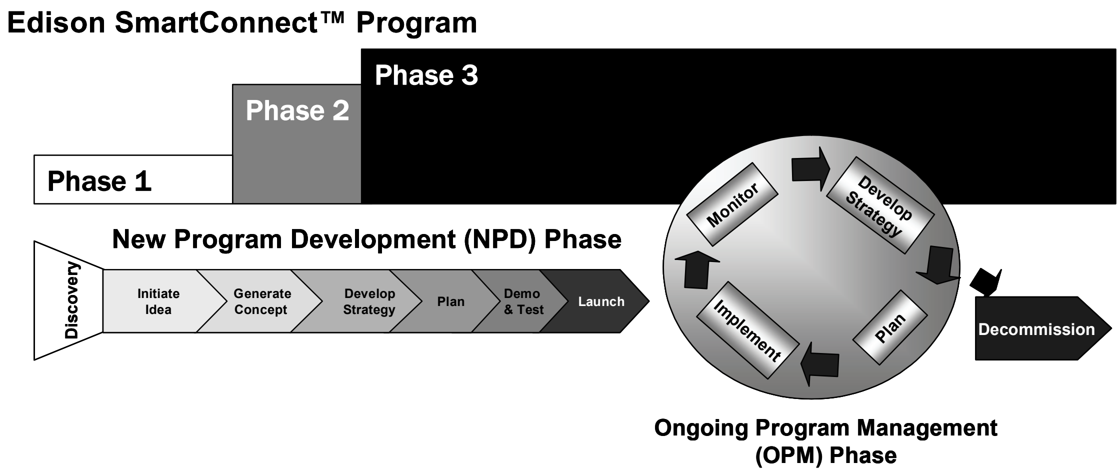
[19] 2003–2004 Nielson Universe Estimates, DMA Ranking and Advertising Age Magazine, July 24, 2000.

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

[21] 2004, Nielson Media Research.

Figure III-7
Edison SmartConnect™ Product Development Life Cycle



(1) New Program Development

New Program Development began in Phase I and is expected to continue through the first portion of deployment for current portfolio of new tariffs, programs and services enabled by Edison SmartConnect™. Activities prior to launch are intensive research composed of the following steps:

- Initiate Idea – identification of conceptual customer tariffs, programs and services and preliminary customer surveys regarding the concept of advanced metering.
- Evaluate Concept – investigation of high-level technical and market unknowns to clarify scope, limitations, impacts and the overall feasibility of the project, including preliminary financial assessment.
- Develop Strategy – extensive market and customer analyses accompanied by more detailed financial assessment to determine the reasonableness and cost effectiveness require for 'go, no go" decision.

- Create Program Plan – detailed implementation planning for all aspects including: demo and testing, scope, marketing channel strategy, issues and operational impacts.
- Demo and Test – execution of demo and test with sample set of customers and associated program refinements based on customer feedback.
- Launch Program – implementation of final plan.

(2) Ongoing Program Management

Once a program is implemented, SCE actively monitors the adoption, retention, and customer satisfaction as necessary to determine what adjustments must be made, including decommissioning. Similar to the development portion of the program life cycle, SCE employs proven standards of practice, summarized by the following:

- Monitor Program – performance tracking of the program's planned goals, such as enrollment, retention and customer satisfaction in order to provide valuable feedback required by the program managers if program changes are warranted.
- Develop/Refine Strategy – if warranted based on monitoring activities, a reassessment of program strategy to better align with new market conditions, including identification of new program initiatives or enhancements.
- Update Program Plan – development of the necessary revisions to program plan based on refinement strategy for enhancing the program.
- Launch Enhanced Program – implementation of improved program plan and begin the maintenance process for the enhanced program.
- Decommission – programs determined to be ineffective based on a variety of reasons will be decommissioned.

4. Estimated Costs of Customer Tariffs, Programs and Services

Table IIII-9 shows the estimated O&M and capital costs needed to deliver advanced customer tariffs, programs and services enabled by Edison SmartConnect™. These estimated costs are comprised of two functions: Demand Response Development and Administration, and Marketing and Customer Communications. As shown in Table III-9, 100 percent of the estimated total $112.1 million is O&M expense. As described earlier in this section, the primary purpose of this entire deployment area is to implement the required changes to SCE's existing operations to develop, market and deliver value added services available through an advanced metering infrastructure. A more detailed discussion about each function is in subsequent parts of this section.

Table III-9
Estimated Costs for Customer Tariffs, Programs and Services
(Millions of Nominal Dollars, Rounded)

Line No.	Description	O&M	Capital	Totals
1.	Marketing & Customer Communications	70.2	0.0	70.2
2.	Demand Response Development and Administration	41.9	0.0	41.9
3.	**Totals**	**112.1**	**0.0**	**112.1**

a) Cost Drivers for Outreach and Market Communications

SCE forecasts $70.2 million in O&M expenses for outreach and market communications activities during the Deployment Period. The marketing activities for Edison SmartConnect™ involve two primary activities: (a) initial outreach and (b) communication about the program and marketing of the new tariffs, programs and services. Both of these activities require market research, campaign planning, marketing and advertising content development, and ongoing market management.

The initial outreach activities about Edison SmartConnect™ are included in the estimated costs. In addition, the estimated costs for this activity include educating customers about the Edison SmartConnect™ program, and communicating the purpose of the program and a high-level deployment plan in a timely and effective manner. Continuous market research will also be conducted to gage the effectiveness of SCE's outreach and educating campaigns so that SCE may improve its outreach efforts for this activity as necessary. Furthermore, this activity includes the initial welcome notification to customer as meters are installed.

Among the new offerings, PCT and PTR are expected to require the most marketing as these are new programs that leverage new technology that was not previously available to SCE customers. As discussed earlier, the opt-in TOU tariff for residential customers is an existing tariff offering that will require significant marketing expense to educate customers about potential costs saving that can be achieved through energy consumption behavior. This educational process is comprised of customer tariff education and customer energy usage and energy informational tools (*e.g.,* internet access to energy usage and cost). The marketing of the tariff offerings such as CPP and TOU for small and medium commercial customers is included in this area, as well as, the estimated costs for development and management of web-enabled tools and communications. These costs include labor and non-labor costs to develop, implement and provide ongoing management of the new web-based energy information tools, customer educational material development/print and customer support to address customer navigational and energy information related questions.

b) Cost Drivers for Demand Response Development and Administration

The $41.9 million in forecasted O&M expense for development and administration of new demand response offerings is comprised of two primary activities: PCT rebates and program management. This is based on providing a rebate of up to $125 to each eligible customer that has purchased and installed an Edison SmartConnect™/Title 24 compliant PCT and enrolls in SCE's PCT program which will be Title 24 compliant. The estimated O&M expense is primarily for labor related to the program management of the new offerings. This includes development of customer enrollment policies and procedures, implementation of new policies and procedures, and execution and ongoing management of the new programs.

c) Expected Annual Expenditures for Customer Tariffs, Programs and Services

Table III-10 shows the annual expenditures for Customer Tariffs, Programs and Services is purely O&M expenses. The O&M expense is driven by SCE's mass meter installation plan, which begins in 2008 and concludes in 2012.

Table III-10
Expected Annual Expenditures for Customer, Tariffs, Programs and Services
(Millions of Nominal Dollars, Rounded)

Line No.	Description	2007	2008	2009	2010	2011	2012	Totals
1.	O&M	0.0	5.5	17.0	21.6	32.6	35.5	112.1
2.	Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	**Totals**	**0.0**	**5.5**	**17.0**	**21.6**	**32.6**	**35.5**	**112.1**

E. Customer Service Operations

A significant portion of SCE's deployment costs will result from the impact deployment activities will have on SCE's existing customer service operations. The two most significantly impacted customer service operational areas will be billing services and the call centers. Both these areas are expected to incur incremental costs during the Deployment Period and a summary of these impacts are discussed in the following subsections. Further discussion of the ongoing customer service operation impacts from Edison SmartConnect™ is contained in Exhibit SCE-3, where post-deployment impacts are discussed as part of the cost benefit analysis for the entire program.

1. Billing Services

Billing Operations will be affected by a significant increase in manual exceptions processing resulting from usage validation issues expected during the Deployment Period. There will also be an increase in the number of energy theft cases identified during the meter installation process, which will have to be resolved by the billing organization.

Billing Services will perform three types of Revenue Protection activity during deployment based on tip cards that are received from the field: (1) processing tips – identifying energy theft or billing errors, putting this information in a database, and determining the need to rebill; (2) rebilling customers where warranted; and (3) performing collections activities on those customers who are rebilled. The Revenue Protection process will be initiated through the detection and analysis of unusual usage patterns by analysts using the back office systems (MDMS). Other billing and collection activities are expected to remain the same. Quality assurance checks on new rates, ad hoc requests from customers to help them analyze and understand the new tariffs and program options, and inquiries related to marketing initiatives utilizing customer bill statements will also impact the billing organization.

2. Call Center

On-going call volume related to routine service connections, credit issues and service interruptions will continue in a "business-as-usual" manner while additional call volume will result from customer inquiries related to meter installations, access to usage data, new customer tariff options such as the Peak Time Rebate program, Critical Peak Pricing (CPP) and Time of Use (TOU) rate options. The call center will also need to conduct specialized training necessary to prepare customer service representatives to respond to the complex issues accompanying the new metering capabilities. The call center will also undergo some procedural changes related to customer turn-on and turn-off orders and connect and disconnect orders, which will now be handled from the call center due to the remote connect and disconnect capabilities of the new meters.

3. Estimated Costs for Customer Service Operations

Table III-11 forecast $84.1 million in costs for this category. This is comprised of $78.9 million in O&M expense and $5.2 million in capital expenditures. For Edison SmartConnect™, there are two key activities that make up customer service operations: Billing Services and Call Center. SCE expects to expand its existing operational areas to support these activities as a result of the new tariffs, programs and services enabled by Edison SmartConnect™.

Table III-11
Estimated Costs for Customer Service Operations
(Millions of Nominal Dollars, Rounded)

Line No.	Description	O&M	Capital	Totals
1.	Billing Services	55.2	0.0	55.2
2.	Call Center	23.7	5.2	28.9
3.	**Totals**	**78.9**	**5.2**	**84.1**

a) Cost Drivers for Billing Services

Billing Services are forecasted to require $55.2 million in O&M expense. SCE expects to incur additional O&M expense related to quality assurance checks of new tariff offerings enabled by Edison SmartConnect™. SCE also expects an increase in customer inquiries about their bill due to these new tariff offerings. Implementation of Edison SmartConnect™ will require process improvement support activities in how bills are processed. Planned activities include: 1) documenting related billing business processes, 2) implementing necessary process changes so that they are integrated across all billing operational groups to support deployment, and 3) developing and implementing new requirements to address billing and revenue reporting system changes for Edison SmartConnect™ programs and tariffs in accordance with regulatory requirements. As customers receive new meters, SCE expects to experience increased manual exceptions processing as the billing system high or low read validations are changed.

As previously discussed in Section B of this Chapter, SCE expects to uncover potential energy theft cases during meter installations which will require incremental O&M expenses as well in SCE's revenue services operations to help validate and resolve these cases. These costs are reflected in SCE's forecasted O&M for billing services.

b) Cost Drivers for Call Center

Call center costs are forecasted to be $23.7 million in O&M expense and $5.2 in capital expenditure. The primary driver of these costs is the expected increase in customer call volume during the Deployment Period. Not only does SCE expect customers to contact the Call Center in regards to installation activities, but also expects significant increases in call volume due to customer inquiries about the new tariffs, programs and services. Customers will have many new options available to them and will want additional detailed information prior to making a decision. Some inquires will be fulfilled by information on the SCE website, however, the majority of the detailed inquiries is expected to be handled by the call center.

c) Expected Annual Expenditures for Customer Service Operations

Table III-12 shows the annual capital and O&M expenditures for Customer Service Operations. The O&M expense is driven by SCE's mass meter installation plan, which begins in 2008 and concludes in 2012. The capital expenditures are for facility improvements required to accommodate the additional resources required to respond to the increase in call center activity.

Table III-12
Expected Annual Expenditures for Customer Service Operations
(Millions of Nominal Dollars, Rounded)

Line No.	Description	2007	2008	2009	2010	2011	2012	Totals
1.	O&M	0.0	4.2	16.1	20.2	20.9	17.4	78.9
2.	Capital	0.0	0.9	4.3	0.0	0.0	0.0	5.2
3.	**Totals**	**0.0**	**5.1**	**20.5**	**20.2**	**20.9**	**17.4**	**84.1**

Some benefits will start to accrue during the Deployment Period as well. These include avoided capital costs of no longer needing to purchase electromechanical meters for customer growth or to replace failed existing meters during the Deployment Period, and the avoided cost of new customer meter sets that otherwise would have occurred. Similarly, avoided labor costs will begin accruing as early as 2009 resulting from the elimination of routine meter reading routes, the introduction of the automatic connect/disconnect capabilities of the Edison SmartConnect™ system, and the ability to obtain on-demand meter reads, thus eliminating the need for “pick-up” reads.

Further discussion of the ongoing customer service operation impacts from Edison SmartConnect™ is contained in Volume 3, where SCE details the post-deployment impacts as part of the cost benefit analysis for the entire program.

F. Overall Program Management

The success of the Edison SmartConnect™ program is highly dependent on the coordinated execution of all the interrelated functional areas responsible for deployment activities. It is standard practice for large and complex projects such as Edison SmartConnect™ to be governed through a program management office (PMO) to provide the proper level of management oversight for the entire project. SCE has established a PMO to manage the project to meet the defined scope, schedule and budget for deployment and operational activities during the Deployment Period. SCE is using industry best practices related to overall project management and technology specific management techniques. The PMO is made up of a team of experienced SCE project managers and contracted project management experts. The PMO function will remain in-tact through the deployment phase and into the post-deployment operational phase as the project closes out and becomes operational.

The PMO is responsible for overall program integration, program execution of scope, schedule, budget, performance monitoring and reporting, contract administration, program and financial controls, benefits realization and corporate and regulatory compliance. The PMO also provides the overall program governance structure and framework to ensure timely and effective decision making, risk management and issues resolution. The PMO is accountable for effective communication among external and internal stakeholders to help them achieve an understanding of the Edison SmartConnect™ program to facilitate the program objectives throughout the Deployment Period.

In summary the PMO will utilize best practices for activities that can be grouped into the following functions. The PMO staff is organized in a similar structure.

- Project Management - management of overall program scope, schedule, budget and resources consistent with the Project Management Institute's Project Management Body of Knowledge. This effort includes management of related risks through the ongoing identification and resolution of execution issues during the Deployment Period.
- Financial Controls – this includes prudent support of the fiscal controls required to manage the deployment costs within the Commission's final decision, and complying with SCE's corporate financial policies including adherence to Sarbanes-Oxley.
- Contract administration – this includes activities to manage the payment of services and products consistent with the negotiated terms and conditions based on the performance and/or deliverables of the respective vendors.
- Regulatory support and compliance – this includes activities required to support the litigation process for this application, compliance requirement resulting from the Commission's final decision, and compliance with SCE's corporate governance protocols.
- Communications – a program with the scale and complexity as Edison SmartConnect™ requires the coordinated action of a very large number of personnel both SCE resources as well as contract.

At the peak of deployment in 2009 through 2012, this program will have about 700 people incrementally engaged full-time on the program. This number will be augmented by more than 300 people that are engaged on a part-time basis. Communications are an essential element of the management strategy to keep the organization aligned to the objectives and focused on the deployment tasks. Additionally, a major risk mitigation strategy is to maintain strong industry working relationship to share lessons learned and best practices to increase SCE's overall effectiveness.

1. Program Management Organization Objectives

PMO objectives are to keep the program on target, on time, and on budget. Included within the PMO responsibilities is the Edison SmartConnect™ business plan development, which includes a thorough and on-going financial assessment of the cost-effectiveness of the program and the internal management approvals and external regulatory approvals necessary to keep the program progressing forward. This also includes management of the project contingency which involves continuous monitoring of actual expenditures, forecasts and variance analyses to determine program progress and the degree to which contingency may be required to satisfy legitimate changes in scope, schedule, budget and/or resources. More detailed discussion of how the project contingency was estimated is provided in Chapter IV of this exhibit.

2. Estimated Costs for Project Management During Deployment

Table III-13 shows the estimated O&M and capital costs for overall program management during the Deployment Period. As shown, SCE estimates $45.6 million for PMO activities. The program management area will help manage interrelationships between the different deployment areas in addition to maintaining consistency and cost-effectiveness for the program's general and administrative activities. A more detailed discussion about each function is in subsequent portions of this section.

Table III-13
Estimated Costs for Overall Program Management
(Millions of Nominal Dollars, Rounded)

Line No.	Description	O&M	Capital	Totals
1.	Program Management Functions	37.5	8.1	45.6
2.	**Totals**	**37.5**	**8.1**	**45.6**

a) Cost Driver for Program Management Labor

The program management costs include $37.5 million in O&M expenses and this accounts for 82 percent of the total PMO costs. To maintain effectiveness, the PMO team is comprised of multiple disciplines including finance, regulatory, and project management.

The PMO cost estimate also includes non-labor expenses required to support the non-field Edison SmartConnect™ project team personnel, which will be as high as 155 people during the Deployment Period. PMO cost estimates for this larger team include expenses like facilities, travel and other personnel-related expenses required to support these resources.

b) Expected Annual Expenditures for Overall Program Management

Table III-14 shows the annual expenditures for Program Management during the Deployment Period. The capital costs during the beginning of the Deployment Period are related to the installation and setup of facilities, primarily office space. The O&M expense is greater during the earlier years as SCE ramps up, however it does reflect that the program management resources required to be maintained throughout the Deployment Period.

Table III-14
Expected Annual Expenditures for Overall Program Management
(Millions of Nominal Dollars, Rounded)

Description	2007	2008	2009	2010	2011	2012	Totals
O&M	0.0	9.1	8.4	7.3	6.5	6.2	37.5
Capital	0.0	7.7	0.0	0.0	0.0	0.3	8.1
Totals	**0.0**	**16.8**	**8.4**	**7.4**	**6.5**	**6.5**	**45.6**

IV.

CONTINGENCY

The cost estimates for the Edison SmartConnect™ project contain uncertainty due to various risks associated with a project of this nature and magnitude. New technologies enabling the metering and communication systems and the pioneering nature of the new products and services SCE plans to offer in concert with its full scale meter deployment program, require that a comprehensive risk assessment be included with the cost estimates associated with certain key elements of the program. As part of SCE's risk mitigation strategy, contingencies have been included with SCE's cost and benefit estimates in order to help quantify this element of risk. Some of the key areas where contingency is required to mitigate execution risks include:

- Price differences that occur between the RFP, contracted terms and the ultimate final vendor payments (as discussed in Chapter III, part A.4);
- Back office systems cost variances due to uncertainties related to data processing, storage requirements, varying levels of vendor warranties and support, and the difference between expected and actual system integration efforts (as discussed in Chapter III, part C.5);
- Uncertainties related to the number of billing exceptions processed (as discussed in Chapter III, part E); and
- Risks related to the management and implementation of the field deployment, and realization of deployment-related benefits on schedule (as discussed in Chapter III, part B.4 and Chapter V).

SCE applied a widely adopted Monte Carlo statistical approach to create a probabilistic range around its cost estimates. This approach utilizes high-low ranges for each cost and benefit estimate, to create a probability distribution for the likely overall cost of the SmartConnect deployment. Each estimate can take on values up to the "high" range, or down to the "low" range, which is expressed as a percentage. For example, a cost of $100, which is estimated to range between +30% and -20%, would take on a value of between $130 and $80 in the Monte Carlo analysis. The software assigns these values randomly to each cost estimate, and produces a probability distribution for the overall SmartConnect model.

Using a not-to-exceed confidence level of 90 percent, SCE estimates a statistically reasonable contingency of $147.3 million for the Deployment Period. SCE believes this provision for contingencies is an essential aspect of SCE's business case. Provision for such contingencies is a widely accepted standard practice in project management and cost estimating as defined by both PMI and American Association of Cost Engineers. The Commission has already recognized the relevance of contingency to the AMI projects and established a precedent of including similar provisions for contingencies with both PG&E's and SDG&E's AMI programs.[22] Thus, SCE believes it is reasonable and prudent to provide for similar contingency in its meter deployment project as well.

SCE's contingency estimates are shown in Table IV-15 for each of the deployment years.

Table IV-15
Estimated Contingency
(Millions of Nominal Dollars, Rounded)

Description	2008	2009	2010	2011	2012	Totals	Present Value
O&M	3.2	6.3	7.6	8.3	7.6	33.0	(24.2)
Capital	9.8	28.7	32.1	30.3	13.3	114.3	(85.8)
Totals	13.0	35.0	39.8	38.7	20.9	147.3	(110.0)

SCE proposes to post actual incremental SmartConnect costs to the balancing account, and to post forecast benefits on a per-meter, per-month basis as meters are installed and activated. SCE is subject to forecast risk on both the costs of the deployment, as well as the initial benefits to be realized from SmartConnect during the Deployment Period. The contingency analysis reflects the increased uncertainty due to the relatively early stage of technology adoption. It is reasonable to permit SCE to utilize its project contingency for any unanticipated SmartConnect deployment costs, whether those arise from increases in estimated costs, or from unanticipated delays in realizing benefits from the meter deployment.

[22] *See* D.06-07-027 at p. 12; *also* D.07-04-043.

V.

DEPLOYMENT PERIOD COSTS AND BENEFITS

SCE's proposed deployment costs and the cost recovery mechanism presented in Volume 5 (SCE-5) of this Application include the costs and benefits expected to be incurred during the Deployment Period.[23] Costs incurred prior to 2008 have already been authorized in prior proceedings and are currently being recovered through the Advanced Metering Infrastructure Balancing Account. Costs and benefits to be incurred after 2012 (post deployment) are considered to be on-going operating costs and will be recovered through future GRC proceedings. Edison SmartConnect™ costs have been isolated into these timeframes for ratemaking and cost recovery purposes.[24]

The majority of the deployment costs are direct Edison SmartConnect™ program-related costs incurred in completing the activities described in the previous Chapters of this volume. Besides these program related deployment costs, Edison SmartConnect™ is expected to impose dramatic impacts on SCE's existing customer service operations. The most significantly impacted customer service operational areas will be the call centers, the billing organization and the training functions. These operational areas will be doing significant amounts of additional work resulting from the deployment stage of Edison SmartConnect™ (*i.e.,* 2008 through 2012). In addition to normal operations, call volume and billing exception processing are expected to increase as customers begin to receive their new meters and begin to utilize the new SmartConnect programs and services.

While the deployment activities will present some operational challenges and added costs in some areas, some benefits will start to accrue during the Deployment Period as well. Most obvious among the early benefits to be derived from the Edison SmartConnect™ program are the avoided capital costs of no longer needing to replace failed existing meters during the Deployment Period, and the avoided cost of installing an interval data recording (IDR) meter when a customer requests a time-of-use

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[23] This Application also requests authorization to transfer certain "deployment" costs proposed in this Application but incurred in 2007 and recorded in SCE's AMI Memorandum Account to the Edison SmartConnect Balancing Account upon a final decision in this proceeding, as contemplated in D.07-07-042, SCE's Phase II Decision.

[24] SCE's Business Case for Edison SmartConnect™ is based on a net present value of all costs and benefits to be realized over the entire life of the project. This analysis is the subject of Volume 3 (SCE-3) of this Application.

rate that otherwise would have occurred. Similarly, avoided labor costs will begin accruing as early as 2009 resulting from the elimination of routine meter reading routes, the ability to obtain on-demand meter reads thus eliminating the need for "pick-up" reads, and finally the introduction of the remote connect/disconnect capabilities of the Edison SmartConnect™ system.

A critical part of this Application for approval to proceed with full deployment of the Edison SmartConnect™ system is the cost recovery mechanism being proposed.[25] Because SCE's 2009 GRC Application will be heard by the Commission concurrently with this Application, SCE has proposed a simple resolution of the potential for either double counting of costs or the counter-part issue of possibly leaving something out. In its 2009 GRC,[26] SCE has developed its Test Year 2009 costs based on a "business-as-usual" approach to customer service operations. That is to say, the Edison SmartConnect™ program and its impact on operating costs were not considered for purposes of developing the 2009 GRC Test Year forecast. This isolates the consideration of incremental costs and benefits derived from Edison SmartConnect™ for the years 2009 through 2012 directly within the scope of this proceeding. In its 2012 GRC Application, SCE expects to treat Edison SmartConnect™ costs and benefits in the opposite manner, including them in its "business-as-usual" cost estimates for the 2012 Test Year, and will reconcile costs and benefits derived in 2012 and beyond at that time.

SCE also expects to obtain some demand response benefits during the Deployment Period in the form of avoided capacity and energy costs.

The costs for the Edison SmartConnect™ project over the Deployment Period are estimated at $1.7 billion. As this is a capital intensive project, SCE forecasts $1.3 billion in capital expenditures over the Deployment Period. These capital expenditures represent 75 percent of the total estimated deployment costs. As will be shown in Volume 5 (SCE-5) of this Application, though these costs are

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[25] SCE's proposed cost recovery mechanism for the Edison SmartConnect™ program is the subject of Volume 5 (SCE-5) of this Application.

[26] *See* SCE Notice of Intent to file a 2009 Test Year GRC tendered with the Division of Ratepayer Advocates on July 23, 2007.

incurred during the Deployment Period the impact of these capital costs on the ratepayer will be spread over the capital recovery period, which extends over the full duration of the project.

Table V-16 is a nominal dollar summary of the estimated costs and benefits expected to be incurred by program area during the Deployment Period. Because the majority of SmartConnect costs relate to the initial meter and infrastructure deployment they are heavily loaded to the front-end of the project, while the benefits are realized over the entire duration of the program. Exhibit SCE-3 will present the net present value of these costs and expenses over the 26 year life of the program and will show the impact of these estimates on the rate payer by converting the nominal dollar amounts to a Present Value of Revenue Requirement (PVRR). As will be discussed in Exhibit SCE-3, SCE's final business case for Edison SmartConnect™ is approximately $109 million positive on a PVRR basis.

Table V-16 shows the Deployment Period costs and benefits in nominal dollar values.

Table V-16
Program Benefit and Cost Analysis – Deployment Period Only
(Millions of Nominal Dollars, Rounded)

Line No.	Description	O&M	Capital	Totals
1.	**Costs**			
2.	Acquisition of Meters and Communication Network Equipment	1.6	836.5	838.0
3.	Installation of Meters and Communication Network Equipment	79.6	216.9	296.6
4.	Implementation and Operation of New Back Office Systems	41.4	149.8	191.2
5.	Customer Tariffs, Programs and Services Costs	112.1	0.0	112.1
6.	Customer Service Operations	78.9	5.2	84.1
7.	Overall Program Management	37.5	8.1	45.6
8.	Contingency	33.0	114.3	147.3
9.	**Costs Totals**	**384.2**	**1,330.7**	**1,714.9**
10.	**Benefits**			
11.	Operational	188.4	89.9	278.2
12.	Demand Response	144.4	71.8	216.2
13.	**Benefits Totals**	**332.8**	**161.6**	**494.4**

Table V-17 illustrates the expected annual Edison SmartConnect™ project costs and benefits by year for the deployment period.

Table V-17
Estimated Deployment Costs and Benefits by Year
(Millions of Nominal Dollars, Rounded)

Description	2007	2008	2009	2010	2011	2012	Totals
Costs							
O&M	1.4	37.0	72.9	88.5	96.6	87.9	384.2
Capital	6.7	114.0	332.2	372.2	351.3	154.2	1,330.7
Annual Costs	**8.0**	**151.0**	**405.1**	**460.7**	**447.9**	**242.1**	**1,714.9**
Benefits							
O&M	0.0	1.2	12.6	55.6	108.2	155.1	332.8
Capital	0.0	4.7	22.2	26.0	38.3	70.5	161.6
Annual Benefits	**0.0**	**5.9**	**34.8**	**81.6**	**146.5**	**225.6**	**494.4**

A. Operational Benefits During the Deployment Period

Over the life of the project, SCE expects 63 percent of project costs to be offset by operational benefits. Operational benefits are defined as the benefits expected to result strictly as a result of changes in SCE's operations and do not include customer demand response benefits.[27] The majority of these impacts, in particular the benefits, is not expected to fully materialize until after full deployment of Edison SmartConnect™. However, SCE does expect to begin realizing certain operational benefits during the Deployment Period which are discussed in detail by Exhibit SCE-3. During the Deployment Period, the functionalities of Edison SmartConnect™ are expected to provide a number of benefits in the following operational areas: Meter Services Organization; Customer Service Operations; Transmission & Distribution; and Back Office Systems.

As shown in Table V-18, these estimated operational benefits are forecast to be $188.4 million in O&M savings and $89.9 million in avoided capital expenditures during the Deployment Period. SCE expects its Meter Services Organization to experience 74 percent of the expected operational benefits during the Deployment Period. The cost drivers for each of these benefit areas are detailed in Exhibit SCE-5.

[27] It should be noted, however, that the project costs used in this calculation include the Customer Tariffs, Programs and Services costs that enable the customer demand response.

Table V-18
Estimated Operational Benefits During Deployment Period
(Millions of Nominal Dollars, Rounded)

Line No.	Description	O&M	Capital	Totals
1.	Meter Services	169.7	88.8	258.5
2.	Customer Service Operations	12.2	0.0	12.2
3.	Back Office Systems	1.6	1.1	2.7
4.	Transmission and Distribution	4.8	0.0	4.8
5.	**Totals**	**188.4**	**89.9**	**278.2**

Table V-19 shows the expected annual operational benefits during the Deployment Period. About 54 percent of these benefits are expected to be O&M related. In addition, SCE expects to realize the benefits to increase as meters are deployed, starting from $5.9 million in 2009 and growing to $108.6 million in 2012.

Table V-19
Expected Annual Operational Benefits During Deployment Period
(Millions of Nominal Dollars, Rounded)

Line No.	Description	2007	2008	2009	2010	2011	2012	Totals
1.	O&M	0.0	1.2	8.2	29.0	60.7	89.3	188.4
2.	Capital	0.0	4.7	22.2	26.0	17.7	19.3	89.9
3.	**Totals**	**0.0**	**5.9**	**30.3**	**54.9**	**78.4**	**108.6**	**278.2**

B. Demand Response Benefits During the Deployment Period

A primary aspect of the State's energy policy objectives is optimizing the use of demand response to help ratepayers control energy costs and provide favorable societal benefits, such as the reduction of green house gases. In support of these objectives and SCE's own corporate goals, SCE plans to offer Edison SmartConnect™ enabled tariffs, programs and services as soon as SCE initiates mass meter deployment. A summary of these programs is provided in Chapter III of this Exhibit, where SCE also provides the forecast costs for developing, marketing and administering these programs during the Deployment Period. A detailed description of these programs is provided in Exhibit SCE-4.

The benefits of demand response are major contributors to SCE's economic analysis of Edison SmartConnect™ detailed in Exhibit SCE-3. The benefit drivers for demand response are primarily the technical assumptions for customer enrollment, program participation, and elasticity, which are all described in Exhibit SCE-4. The benefit is the assumed cost of avoided capacity and energy costs. Table V-20 shows that the demand response benefits expected to occur during the deployment period is forecast to be $216.2 million in avoided capacity and energy costs.

Table V-20
Expected Annual Demand Response Benefits During Deployment Period
(Millions of Nominal Dollars, Rounded)

Line No.	Description	2007	2008	2009	2010	2011	2012	Totals
1.	O&M	0.0	0.0	4.4	26.6	47.5	65.8	144.4
2.	Capital	0.0	0.0	0.0	0.0	20.6	51.2	71.8
3.	**Totals**	**0.0**	**0.0**	**4.4**	**26.6**	**68.1**	**117.0**	**216.2**

Appendix A

Witness Qualifications

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF LISA D. CAGNOLATTI

Q. Please state your name and business address for the record.

A. My name is Lisa D. Cagnolatti, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the Director of the Customer Communications Organization

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor's degree in Chemical Engineering from UCLA and an MBA from Pepperdine University. I have over 20 years of experience in the utility industry including positions of increasing responsibility in Marketing, Environmental Affairs, Regulatory Affairs, Transmission and Distribution, and Customer Services.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of this Exhibit SCE-2 as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF PAULA M. CAMPBELL

Q. Please state your name and business address for the record.

A. My name is Paula M. Campbell, and my business address is 2131 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am currently leading the Program Management Office for the Advanced Metering Infrastructure (AMI) Program at Southern California Edison (SCE). In this role, I am responsible for overall program integration, program execution of scope, schedule, budget, performance monitoring and reporting, contract administration, and program and financial controls. My direct and matrixed staff includes SCE managers, project managers, subject matter experts, and external consultants.

Q. Briefly describe your educational and professional background.

A. I am currently taking coursework to complete my Bachelor of Science Degree in Business Administration from the University of Phoenix. I have also completed periodic executive education programs at Columbia University and University of Chicago with an upcoming Wharton Executive Development program at the University of Pennsylvania scheduled for September 2007. I am also a certified Human Resource Generalist with the Society for Human Resource Management. I began my career at Southern California Edison in the Customer Service Business Unit in October of 1990. In 1992, I transitioned to Information Technology to work on the development of the Customer Service System (CSS). I was promoted to project manager in 1994 supporting a variety of projects and programs in Customer Service Business Unit. I became a Manager in 1998 responsible for the residential segment of the call center operations, including 13 supervisors and 220 customer service representatives. In 2004, I was promoted to my current position.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of this Exhibit SCE-2 as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF PAUL J. DE MARTINI

Q. Please state your name and business address for the record.

A. My name is Paul J. De Martini, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the Edison SmartConnect™ Program Director. I am responsible for managing all aspects of the AMI program feasibility, system design, development, and deployment efforts.

Q. Briefly describe your educational and professional background.

A. I hold a Master of Business Administration (M.B.A) degree from the University of Southern California and a Bachelor of Science (B.S.) degree in Applied Economics from the University of San Francisco. I also completed Certificates in Project Management from the University of California, Berkeley and Technology Management from the California Institute of Technology. I have been at Southern California Edison for about five years during which I was the IT Project Manager on AMI beginning in 2004, prior to assuming the overall program management responsibility in 2005. Relevant positions prior to joining Southern California Edison included Vice President of the Energy Strategy practice at ICF International in 2000-2002 with a focus on demand response, advanced metering and distributed generation technologies. I began my career at PG&E Corporation in both regulated and unregulated businesses for nearly twenty years. I held positions at the utility with increasing responsibility involving electric systems operations, T&D project management, and wholesale power procurement and ultimately at the unregulated subsidiary PG&E Energy Services as Vice President, Integrated Services.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of this Exhibit SCE-2 as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?
A. Yes, it was.
Q. Insofar as this material is factual in nature, do you believe it to be correct?
A. Yes, I do.
Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A. Yes, it does.
Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF JAMES F. GREGORY

Q. Please state your name and business address for the record.

A. My name is James F. Gregory, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the Edison SmartConnect™ Field Deployment Manager. I am responsible for managing all aspects of the field installation of all Edison SmartConnect™ meters whether installed by Contractor or SCE resources.

Q. Briefly describe your educational and professional background.

A. I hold a Master of Business Administration (M.B.A.) degree from Loyola College in Baltimore, Maryland and a Bachelor of Science (B.S.) degree in Mechanical Engineering from the University of Maryland. I have been at Southern California Edison for less than 1 year. Relevant positions prior to joining Southern California Edison included Manager – Electric Construction & Maintenance at Lee County Electric Cooperative in Southwest Florida in 2004-2007 with a focus on executing field construction and maintenance activities utilizing contractor and company resources performing electric substation, transmission, and distribution work. Prior to that I was Vice President – Operations at Central Locating Service (A wholly owned subsidiary of Asplundh) in 2000 – 2004 with a focus on managing an international underground utility locating contracting organization with over 2000 employees and annual revenue over $100M/yr. Earlier, I was Director – Contract Administration & Resource Management and Director - Capital Construction in the Distribution Division for Baltimore Gas & Electric between 1995-2000 with a focus on business process re-engineering, utility contracting/procurement, resource planning, gas & electric distribution construction, and commercial metering installation.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of this Exhibit SCE-2 as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF ERIC S. HELM

Q. Please state your name and business address for the record.

A. My name is Eric S. Helm, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. As Manager of Financial Planning and Analysis for the Customer Service Business Unit, I am currently responsible for financial modeling, project analysis, and product and service pricing for major projects within the business unit.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Arts degree in Economics from Claremont McKenna College, and an MBA with a Finance concentration from California State University at Long Beach. I joined Edison's Residential Energy Management staff in 1983, working on residential rebate and home energy survey programs. I held analyst positions in the Revenue Requirements department from 1987-89, and analyst and management positions in SCE's Treasurer's department from 1989-1996, primarily in the Investor Relations group. I have managed the CSBU Financial Planning function since 1996. I have previously testified before this Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of this Exhibit SCE-2 as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A. Yes, it does.
Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF CHARLIE C. HU

Q. Please state your name and business address for the record.

A. My name is Charlie Hu, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am currently leading the Business Design effort for Edison SmartConnect™ Program at Southern California Edison. In this role, I am accountable for all back office activities needed to support Edison SmartConnect™. The back office activities include designing and implementing the business processes and information technologies needed to support Edison SmartConnect™. My direct and matrixed staffs include SCE project managers, subject matter experts, external consultants, and vendors.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Science (B.S.) degree in Computer Science from California State University of Los Angeles. I also completed the Management Program from Columbia University Graduate School of Business and various graduate classes from Pepperdine University. I have been in Southern California Edison for over seventeen years. I was in the Information Technology organization the first seven years where I held positions with increasing responsibility involving system development and implementation of our current billing system. The last ten years include leadership roles involving implementation of various major process improvement initiatives in the Customer Service organization with focus in the areas of customer service, metering, meter reading, field services, billing, and revenue collections.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of Exhibit SCE-2 as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?
A. Yes, it was.
Q. Insofar as this material is factual in nature, do you believe it to be correct?
A. Yes, I do.
Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A. Yes, it does.
Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF SETH KINER

Q. Please state your name and business address for the record.

A. My name is Seth J. Kiner, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the Director of Customer Experience Management, in the Customer Service Business Unit, at Southern California Edison. I have responsibility for the development and implementation of customer communication and outreach efforts (collaborating with various parts of SCE) to all classes of customers, enhancement of delivery channels such as *sce.com* to meet customers' preferences, customer satisfaction management and employee communication within the Customer Service Business Unit.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Business Administration, with a major in Marketing, from Arizona State University in 1983. I have over 21 years of management experience leading marketing, product management and communications efforts to reach diverse audiences, working in a variety of industries including: utility, not-for-profit, financial services and telecommunications. My three most immediate positions prior to SCE were: Director of Marketing, KPMG, LLC; Vice President of Marketing, United Way of Greater Los Angeles; and Director of Marketing and Marketing Communications, Transamerica Life Companies.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of this Exhibit SCE-2 as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF LAWRENCE M. OLIVA

Q. Please state your name and business address for the record.

A. My name is Lawrence M. Oliva, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am a Director in SCE's Customer Services Business Unit and I lead a group entitled Tariff, Programs and Services. This group is responsible for SCE's Demand Response programs.

Q. Briefly describe your educational and professional background.

A. I earned a Bachelor of Science Degree in Civil Engineering from Southern Methodist University in 1972. Prior to joining SCE as an employee this year, I was a business consultant in the energy industry for over 30 years. I was a principal and director of an international economics consulting firm, Putnam, Hayes and Bartlett, Inc., and a business consulting partner of Arthur Andersen. In past four years, I provided consulting services to SCE in the areas of demand response and advanced metering.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of this Exhibit SCE-2 as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

Application No.: 07-07-

Exhibit No.: SCE-3

Witnesses:

L. Cagnolatti
B. Curry
P. De Martini
K. Ellison
E. Helm
C. Hu
B. Hodges
L. Oliva

SOUTHERN CALIFORNIA
EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

EDISON SMARTCONNECT™ DEPLOYMENT FUNDING AND COST RECOVERY

Exhibit 3: Financial Assessment And Cost Benefit Analysis

Before the

Public Utilities Commission of the State of California

Rosemead, California

July 31, 2007

#1386653

EDISON SMARTCONNECT™ DEPLOYMENT FUNDING AND COST RECOVERY

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I.

INTRODUCTION

The purpose of this volume is to present the overall financial assessment and cost benefit analysis for deployment of Edison SmartConnect™, SCE's proposed advanced metering infrastructure. The cost benefit analysis is a necessary component to assist the Commission in determining the reasonableness of this Application. The results of this analysis provide reasonable assurance that Edison SmartConnect™ will produce customer benefits far in excess of the project costs over the full life of the project.

SCE planned its advanced metering project in three phases. During Phase I, in 2006 SCE undertook a complete revision of its cost benefit analysis. When the revised "preliminary" cost benefit analysis was completed in December 2006, the results showed a positive present value revenue requirement (PVRR) of $101 million.[1] SCE then proceeded with Phase II, focusing on pre-deployment activities during 2007 and revised its preliminary analysis to include updated cost and benefit assumptions as of mid-year 2007, incorporating the results of initial product tests in the lab and responses to its technology request for proposals (RFP). The final cost benefit analysis detailed in this volume concludes the Edison SmartConnect™ project is expected to produce customer benefits of $109 million in PVRR. This represents a $1 billion improvement over the initial cost benefit analysis presented by SCE in its "best-case" full deployment scenario (Scenario 4) in March 2005.[2]

The improvements that have occurred over the past two years are the result of fast moving technology improvements, some of which were motivated by SCE in its endeavor to deliver a cost effective AMI solution that fully satisfies the Commission's functionality requirements. The vast improvements in benefits largely result from the incorporation of a remote service (connect/disconnect) switch into the meter, improved communication system coverage and functionality, improved meter life, and refined energy conservation and customer demand response programs based, in part on the enabling

[1] The December 2006 analysis was still considered "preliminary" because some critical information was still unknown pending the results of product testing and the yet to be received responses to SCE's RFP.

[2] A. 05-03-026, filed on March 30, 2005.

Home Area Network (HAN) interface technology.[3] These improvements are described and quantified in SCE's August 2005 *AMI Conceptual Feasibility Report,* which was filed as part of SCE's Phase II AMI Application (A.06-12-026).[4]

Chapter II of this volume provides an overview of SCE's overall financial assessment and cost benefit analysis. The results of the cost-benefit analysis are summarized and the analytical approach is described. Chapter II shows that the result of the cost benefit analysis is positive on a PVRR basis.

Chapter III includes a detailed discussion of SCE's cost benefit analysis presented in four separate parts. Part A recaps pre-deployment costs currently being incurred in Phase II. Since these pre-deployment costs have already been authorized and largely spent at the time of this proceeding, they could be viewed as "sunk costs." SCE believes, however, that a fair assessment of Edison SmartConnect™ should include these pre-deployment costs since they are an essential part of the total project. Thus, the pre-deployment costs are included in the financial assessment. Part B of Chapter III provides a recap of the estimated costs during the deployment period, 2008-2012, as detailed in Volume 2 (Exhibit SCE-2) of this Application. Part C presents the estimated post-deployment period costs (2013 – 2032) and includes a detailed discussion of the major cost drivers and assumptions. Part D of Chapter III provides a detailed description of the quantifiable benefits of Edison SmartConnect™ during the deployment period (2008-2012) and the post-deployment period (2013-2032). As described in Part D, Edison SmartConnect™ is expected to provide wide ranging operational benefits as well as demand response benefits driven by advanced tariffs, programs and services.

Chapter IV explains the non-quantified societal benefits that are likely to result from the deployment of Edison SmartConnect™. Though not included as part of SCE's financial

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[3] The Home Area Network (HAN) technology enabled by Edison SmartConnect is described in Volume 2 (Exhibit SCE-2) in Chapter III, Part D.3.c.

[4] *See* A.06-12-026, Exhibit 4, appending SCE's *AMI Conceptual Feasibility Report* dated August 2006, at Table II-1 on p.7.

assessment, the societal benefits of Edison SmartConnect™ are real and should be taken into consideration in assessing the reasonableness of SCE's proposed investment in Edison SmartConnect™.

Finally, Chapter V discusses how the nominal dollars detailed in this Exhibit translate to economic value for ratepayers on a present value of revenue requirement (PVRR) basis. Chapter V also describes the estimated ratio between operational benefits and project costs for SCE's Edison SmartConnect™ over the life of the project. The customer rate impacts and the cost recovery mechanism being proposed by SCE in this proceeding are further described in Exhibit SCE-5 of this Application.

II.

OVERVIEW OF EDISON SMARTCONNECT™ FINANCIAL ASSESSMENT

A. Summary of Financial Assessment

The financial assessment described in this Exhibit incorporates SCE's expected technology selections and current vendor pricing for full deployment based on SCE's analysis of responses to its Request for Proposals issued in December, 2005. Results of SCE's financial assessment are presented in Table II-1.

Table II-1
Project Cost Benefit Analysis Results
($Nominal and 2007 Present Value of Revenue Requirement, in Millions, Rounded)

	Nominal	PVRR
Benefits		
Operational Benefits		
During Deployment Years	278.2	
During Post-Deployment Years	4,299.0	
Demand Response Benefits		
During Deployment Years	216.2	
During Post-Deployment Years	2,792.6	
Subtotal Operational Benefits	4,577.2	
Subtotal Demand Response Benefits	3,008.8	
Total Benefits	**7,586.0**	**2,076.0**
Costs		
Phase II Costs (Pre-deployment)	45.2	
Deployment Costs		
Acquisition of Meters and Communication Network Equipment	838.0	
Installation of Meters and Communication Network Equipment	296.6	
Implementation and Operation of New Back Office Systems	191.2	
Customer Tariffs, Programs and Services	112.1	
Customer Service Operations	84.1	
Overall Program Management	45.6	
Contingency	147.3	
Post-Deployment Costs		
Billing	127.1	
Call Center	93.5	
Meter Services	399.1	
Back Offices Systems	344.4	
Customer Tariffs, Programs and Services	245.0	
Subtotal Pre-Deployment Costs	45.2	
Subtotal Deployment Costs	1,714.9	1,627.0
Subtotal Post-Deployment Costs	1,209.0	340.0
Total Costs	**2,969.1**	**1,967.0**
Total Benefits Less Total Costs	**4,616.9**	**109.0**

The big difference between nominal dollar benefits and the present value of the same benefits is a function of the time-value of the majority of the expenditures occurring in the early years of the project and the majority of the benefits occurring in later years. The present value analysis effectively normalizes these time-value differences affected by the occurrence of the costs verses the benefits.

B. Analytical Methodology Used to Develop the Cost Benefit Analysis

SCE's analysis is a financial comparison of the present value of estimated Edison SmartConnect™ costs and benefits over the useful life of the new infrastructure. Costs and benefit estimates were derived through a rigorous internal process involving the participation of all affected SCE operating departments and using a consistent set of common assumptions. Each department specified their costs and benefits using a discrete set of Cost-Benefit Identification codes, each of which describes a unique project cost or benefit. SCE Business Units specified their labor impacts by indicating SCE job titles and full-time equivalent employees by year, and specified their nonlabor impacts in constant 2006 dollars.[5] Contract labor was classified as nonlabor, to ensure accurate payroll loadings.

These estimated costs and benefits were then applied to the proposed deployment schedule, incorporated with corporate assumptions for annual meter growth and cost escalation factors over the 26 year analysis period starting on January 1, 2007 and concluding on December 31, 2032. The analysis period is the multi-year deployment schedule (2007 through 2012) plus the 20-year useful life of the meters (2013 through 2032). To capture the full useful life of meters installed in the last year of deployment (2012), the analysis extends to 2032. Recognizing that the initial installed Edison SmartConnect™ meters would be more than 20 years old by that time, the analysis assumes a substantial increase in meter failures (and associated costs) as each "vintage" of meters reaches its 20-year service life in 2029, 2030, 2031, and 2032.

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[5] Non-labor estimates were developed in 2006 dollars because that is when this process took place.

Annual costs are escalated for inflation and stated in terms of nominal dollars for each year. In the last chapter of this volume the same costs and benefits are stated in terms of PVRR reflecting the customer rate impacts over the life of the project.

1. Labor Cost Estimation

Labor costs were based on the number of full-time equivalent employees multiplied by the annual labor rate for each job title. Labor rates were based on current 2007 SCE market reference points[6] and labor contracts for each job title, and escalated to the year of incurrence using SCE's proposed 2009 GRC labor escalation rates. Annual labor costs include base wages, results sharing, and payroll loadings such as employee pensions and benefits, and payroll taxes. Payroll loadings (referred to as the Pensions and Benefits or P&B rate) are expressed as a percentage of labor and added to the base labor rates. The P&B rate is based on the incremental costs of health care and other benefit plans, as well as payroll taxes. The P&B rate components were held constant across the business case, with the exception of health care costs, which were assumed to escalate at the rates shown in SCE's 2006 and 2009 GRC health care testimony. Project-specific estimates were developed for Workers' Compensation and Claims impacts for the Meter Services Organization (Field Services, Meter Reading and Meter Technicians) because of the significant impact to the organization (meter readers will be virtually eliminated by SmartConnect™), and because of the higher injury risk of these occupations.

2. Nonlabor Cost Estimation

Nonlabor costs are, with certain exceptions, escalated using SCE's proposed 2009 GRC nonlabor escalation rates. The exceptions are Demand Response-related costs, Worker's Compensation, IT non-labor costs, and the SmartConnect™ meters. Demand Response and Worker's Compensation were in nominal dollars at the workpaper level, and no further escalation was required.

[6] 2006 GRC-approved Market Reference Points with Human Resource's annual adjustments for 2007.

C. Description of Cost/Benefit Estimates

Edison SmartConnect™ project cost and benefit estimates are addressed in Chapter III and presented in nominal dollars in the year they occur. These costs and benefits are addressed in four general categories:

1. Pre-deployment costs;
2. Deployment Period costs;
3. Post-Deployment Costs; and
4. Benefits (operational and demand response) during the Deployment and Post-Deployment Periods.

All included costs are incremental, resulting from Edison SmartConnect™ and do not include any SCE operating and maintenance (O&M) costs or capital costs that would have otherwise been incurred. Any costs that may be displaced or deferred as a result of Edison SmartConnect™ are included as a cost avoidance benefit attributed to Edison SmartConnect™ and will be discussed in the sections on estimated benefits.

D. Societal Benefits of Edison SmartConnect™

Although not quantified, societal benefits are very real and are an important consideration in determining the reasonableness of Edison SmartConnect™. Societal benefits of Edison SmartConnect™ include improvements in customer experience, reductions in energy theft, reduction of green house gases and other potential environmental benefits, as well as benefits expected to result from other Edison SmartConnect™ capabilities. These societal benefits do not directly impact SCE's revenue requirement and they have not been incorporated into SCE's financial assessment of Edison SmartConnect™. Societal benefits are discussed in more detail in Chapter IV of this volume.

E. Edison SmartConnect™ Revenue Requirement and Ratepayer Impacts

The cost effectiveness of Edison SmartConnect™ as it relates to the ratepayer incorporates financial considerations using standard PVRR calculation methods. The return on investment used for determining ratepayer impacts is the return on rate base currently authorized by the Commission.

SCE summarized the results of its financial assessment of Edison SmartConnect™ in terms of the impacts the program will have on its ratepayers. As detailed in Chapter V of this Exhibit, the overall impact of Edison SmartConnect™ on SCE's ratepayers is estimated to be net positive $109 million in 2007 present value dollars.

III.

EDISON SMARTCONNECT™ FINANCIAL ASSESSMENT

This Chapter presents the discussion of Edison SmartConnect™ costs and benefits in three distinct time-periods: the pre-deployment period, which includes costs incurred from January 2007 through December 2007;[7] the deployment period, which includes costs and benefits incurred from January 2008 through December 2012;[8] and the post-deployment period, which includes the costs and benefits for the remainder of the project through December of 2032.

Since SCE's pre-deployment costs are already authorized by the Commission,[9] they will not be discussed in detail in this Exhibit. Instead, SCE provides a recap of the costs approved by the Commission for Phase II, and verifies that these pre-deployment costs are all included in SCE's financial assessment of the overall costs effectiveness of the Edison SmartConnect™ program.

Deployment Period activities and costs are discussed in detail in Exhibit SCE-2 of this Application, and are summarized in this Exhibit. The benefits of the deployment period are summarized in Exhibit SCE-2, and discussed in detail in this Exhibit. All deployment period costs and benefits are also included in the overall cost benefit analysis.

The costs and benefits of the post-deployment period, which includes the calendar years 2013 through 2032, are described in detail in this Exhibit. Thus, SCE's cost benefit analysis includes all costs and benefits incurred or estimated over the entire analysis period from January 2007 through December 2032.

A. Recap of Pre-Deployment Costs

SCE's estimated cost for pre-deployment activities of $45.22 million was authorized in Decision 07-07-042. There are no quantifiable benefits expected during the pre-deployment activities of 2007. At the time of this Application filing, Phase II activities are on schedule and for purposes of the financial

[7] Pre-deployment costs were authorized by the Commission in D.07-07-042, issued July 26, 2007.

[8] This Application also seeks recovery through the balancing account of approximately $8 million in 2007 costs which were classified as "deployment" costs by D.07-07-042, and which will be recorded in the AMIMA during 2007.

[9] *See* D.07-07-042.

assessment, it is assumed that the pre-deployment costs will equal the full $45.22 million authorized by the Commission in D.07-07-042.

B. Summary of Costs Incurred During the Deployment Period (2008 through 2012)

This section summarizes the detailed explanation provided in Exhibit SCE-2 of SCE's forecast costs of Edison SmartConnect™ during the Deployment Period. Deployment Period costs are organized into five functional areas and include a provision for contingencies as summarized in Table III-2 below. The total costs during the Deployment Period are estimated to be $1.7 billion in nominal dollars.

Table III-2
Summary of Estimated Costs During the Deployment Period
(Millions of Nominal Dollars, Rounded)

	O&M	Capital	Totals
Acquisition of Meters and Communication Network Equipment	1.6	836.5	838.0
Installation of Meters and Communication Network Equipment	79.6	216.9	296.6
Implementation and Operation of New Back Office Systems	41.4	149.8	191.2
Customer Tariffs, Programs and Services Costs	112.1	0.0	112.1
Customer Service Operations	78.9	5.2	84.1
Overall Program Management	37.5	8.1	45.6
Contingency	33.0	114.3	147.3
Costs Totals	**384.2**	**1,330.7**	**1,714.9**

C. Post-Deployment Costs (2013 through 2032)

The forecast costs for the post-deployment period are an essential part of the overall cost effectiveness analysis of the Edison SmartConnect™ program. Upon completion of the deployment of Edison SmartConnect™, the post-deployment activities will become part of SCE's on-going operations at that time. As such, SCE expects the ratemaking considerations related to these post-deployment costs and benefits to be reflected in its General Rate Case proceedings beginning in 2012. The post-deployment period costs are those incremental expenses that SCE expects to incur after the full deployment of Edison SmartConnect™ over and above the costs that would be expected if Edison SmartConnect™ were not deployed. SCE anticipates the majority of these ongoing costs will be in the form of O&M expenses. These estimated steady-state incremental costs include the forecast costs to maintain the Edison SmartConnect™ field infrastructure and back office systems, and the costs to support new customer tariffs, programs and services. The estimated costs of additional Edison SmartConnect™ meters required for both customer growth and replacement of failed Edison SmartConnect™ meters are included.[10] Other costs in this category include the incremental costs incurred in the Billing Organization and the call center, and incremental costs to address load forecasting complexities involving enhanced near real-time data available through Edison SmartConnect™.

1. Summary of the Post-Deployment Incremental Cost Estimate

SCE expects to spend $1.2 billion of nominal dollars in steady-state incremental costs over 20 years of the post-deployment period. Table III-3 summarizes these costs by operational area.

Table III-3
Summary of Post-Deployment Estimated Incremental Costs
(Nominal Dollar in Millions, Rounded)

	O&M	**Capital**	**Totals**
Billing	127.1	0.0	127.1
Call Center	93.5	0.0	93.5
Meter Services	104.2	294.9	399.1
Back Office Systems	247.8	96.6	344.4
Customer Tariffs, Programs and Services	245.0	0.0	245.0
Totals	**817.6**	**391.4**	**1,209.0**

The following subsections provide additional discussion about the costs expected during the post-deployment period.

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[10] SCE's cost-benefit analysis includes the full cost of purchasing and maintaining SmartConnect meters for the forecast customer growth and routine meter replacements between 2009 and 2032 and offsets these costs with benefits that include the full avoided cost of new meters for customer growth and routine meter replacements.

2. Post-Deployment Incremental Operating Cost Drivers and Assumptions

a) Billing Costs

The Billing costs primarily relate to an increase in manual processing of billing usage exceptions (*i.e.,* usage problems that require human intervention to resolve in order to correctly bill customers) that are expected after the Deployment Period and driven by new tariffs, programs and services. SCE expects a fairly dramatic increase in billing in the number of usage analyses requested by customers due to more advanced tariffs and the availability of usage data. SCE also expects billing analysis to increase in complexity as a result of the interval meter reads available with Edison SmartConnect™. This increase is expected to begin during the Deployment Period and continue into the Post-Deployment Period.[11] As such, the majority of the costs in this area are for labor required to manage the increase in customer service billing requests driven by the exponential growth in customer usage information. As shown in Table III-4, SCE forecasts the $127.1 million in incremental O&M expenses for its billing operations, in the Post-Deployment Period, and estimates 64 percent to be attributed to exceptions processing.

Table III-4
Estimated Post-Deployment Incremental Operating Costs – Billing Operations
(Millions of Nominal Dollars, Rounded)

	O&M	Capital	Totals
New Bill Presentation and Processes	46.0	0.0	46.0
Exception Processing	81.2	0.0	81.2
Totals	**127.1**	**0.0**	**127.1**

b) Call Center

A significant increase in call volume to SCE's call centers is expected to start during the Deployment Period and continue during the Post-Deployment Period. Costs associated with fielding calls include the per-minute costs of SCE's voice response unit (VRU) and customer service

[11] SmartConnect will collect hourly data for most residential and small commercial customers and 15-minute data for medium and large commercial and industrial customers.

representatives. In addition, in order for the customer to confirm that the premises are safe for electrical service to resume, SCE assumes that all service activation requests will require an additional phone call to the call center where 25 percent of those calls will be handled by a Call Center representative and the remaining 75 percent will be handled through the use of the VRU.

For calls related to disconnection and reconnection of service, SCE assumes that the more efficient automatic disconnect capability of Edison SmartConnect™ (over the manual disconnect process used today) will result in approximately 129,000 more disconnections per year. This increased volume is assumed to translate to two calls to the Call Center per disconnection where 66 percent of those calls will be handled by a Call Center representative and 34 percent will be handled through the VRU. In terms of reconnections, SCE assumed that all these 129,000 additional reconnections will require a call to the Call Center where 25 percent will be handled by an SCE Call Center representative and 75 percent will be handled by the VRU.

Finally, for pre-payment service, SCE assumes that 60 percent of those calls will be handled by a Call Center representative and 40 percent will be handled through the VRU. Of the 60 percent of prepayment calls handled by a Call Center representative, 70 percent of those calls will be handled by SCE's outsourced call center for credit-related calls while the remaining 30 percent will be handled by an SCE Call Center representative.

The incremental cost of the Call Center cost drivers is estimated at $93.5 million in O&M expenses during the Post-Deployment Period. Table III-5 shows that $58.9 million (63 percent) of the anticipated increase in call center costs will be attributed to a significant increase in call volume due to customer impacts from Edison SmartConnect™.

Table III-5
Estimated Post-Deployment Incremental Operating Costs – Call Center
(Millions of Nominal Dollars, Rounded)

	O&M	Capital	Totals
Increased Call Volume	58.9	0.0	58.9
Reconnection Order Handling	34.5	0.0	34.5
Totals	**93.5**	**0.0**	**93.5**

c) Meter Services

The need to acquire new meters for customer growth and replacing failed meters is an ongoing cost expected to continue during the Post-Deployment Period. SCE will require capital dollars to purchase Edison SmartConnect™ meters on an on-going basis after deployment. For modeling clarity, the entire estimated cost of Edison SmartConnect™ meters for both initial deployment and customer growth is included as a cost, offset in part by the avoided cost of procuring electromechanical and solid-state meters, which is included as a capital benefit during the deployment and post-deployment periods. SCE assumes that the labor for installation of growth meters would occur at the same rate as the costs that would have been incurred without Edison SmartConnect™. As a result, the costs for installation of growth meters are not included in this analysis.

The estimated meter operation and maintenance costs also include the incremental cost of travel time for Field Service Representatives (FSRs) to handle the remaining field service orders. With fewer total orders, each FSR will be required to cover a larger territory performing their remaining work and will spend a larger proportion of time traveling. Additional meter technicians and FSRs will be required to work trouble reports and replace faulty meters. The driver for the meter failure cost is the failure rate assumed for the new meters. SCE assumed that one percent of the entire meter population per year will require a visit by an FSR or meter technician to resolve a trouble order where the meter will be replaced with a new Edison SmartConnect™ meter. SCE then reduced these costs by the current costs associated with trouble reports for existing meters to estimate the incremental cost impact.

Table III-6 shows that meter services costs during the Post-Deployment Period are forecast at $294.9 million in capital expenditures and $104.2 million in O&M expenses. The estimated capital expenditures are primarily for the purchase of meters, which equates to 78 percent of the total Meter Services capital forecast. The balance of the Meter Services capital expenditures is related to the normal capitalization of installation labor, equipment and tools for meter testing and maintenance.

Table III-6
Estimated Post-Deployment Incremental Operating Costs – Meter Services
(Millions of Nominal Dollars, Rounded)

	O&M	Capital	Totals
Meter Operations and Maintenance	104.2	64.8	169.0
Meter Purchases	0.0	230.0	230.0
Totals	**104.2**	**294.9**	**399.1**

d) Back Office Systems

The combination of exponential increases in customers' usage data and managing Edison SmartConnect™ enabled tariffs, programs and services for over five million customer accounts will require significant ongoing expansion and management of automated data management and more complex communication network infrastructure. The Back Office Systems costs include the ongoing capital and O&M required to maintain a back office with a considerable increase in hardware, especially storage capacity, and communications network equipment. In addition, the major applications required by Edison SmartConnect™, such as the Meter Data Management System (MDMS) and the Network Management System (NMS), will require ongoing licensing and maintenance, as discussed in Exhibit SCE-2 for the deployment period.

As show in Table III-7, the Post-Deployment Period expenditures for SCE's back office systems are forecast to be $344.4 million. These costs are organized in the same areas as the Deployment Period costs: load control systems; back office systems; and the combination of the MDMS and NMS. The ongoing maintenance of these three areas requires both capital expenditures and

O&M expenses. The capital expenditures include software, processors and storage servers. The O&M expenses are primarily driven by the labor required to maintain and operate the back office assets, which require attention 24 hours a day, 365 days a year.

Table III-7
Estimated Post-Deployment Incremental Operating Costs – Back Office Systems
(Millions of Nominal Dollars, Rounded)

	O&M	Capital	Totals
Load Control Systems	6.1	1.7	7.8
Back Office Maintenance	18.5	18.0	36.5
MDMS and NMS Maintenance	223.2	76.8	300.0
Totals	**247.8**	**96.6**	**344.4**

e) Customer Tariffs, Programs and Services

As discussed in Exhibit SCE-2, SCE expects to implement new demand response options for Edison SmartConnect™ customers during the deployment period. Implementation and maintenance of these programs requires a major marketing program to obtain and maintain an optimal level of customer participation. These activities are expected to continue during the post-deployment period. SCE plans to conduct research on an ongoing basis to assess customer satisfaction and collect customers' suggestions for improvements. Research is expected to be conducted to gauge the effectiveness of SCE's marketing tactics, marketing channels and the overall effectiveness of Edison SmartConnect™ enabled tariffs, programs, and services. This research is then used to modify the tariffs, programs and services as necessary and adjust SCE's marketing tactics. Finally, SCE will have to maintain the operations necessary to successfully implement the programs.

Table III-8 shows that SCE forecasts $245.0 million of ongoing O&M expenses during the Post-Deployment Period for the activities in Customer Tariffs, Programs and Services. SCE plans to use 56 percent of these costs for marketing, such as customer outreach, education and advertising, to help drive the adoption and retention of customer participation in dynamic rates, and demand response programs and energy conservation enabled by Edison SmartConnect™.

Table III-8
Estimated Post-Deployment Incremental Operating Costs – Customer Tariffs, Programs and Services
(Millions of Nominal Dollars, Rounded)

	O&M	Capital	Totals
Marketing	137.4	0.0	137.4
Market Research	15.8	0.0	15.8
Demand Response Administration	64.8	0.0	64.8
PCT Rebates	27.0	0.0	27.0
Totals	**245.0**	**0.0**	**245.0**

D. Benefits during the Deployment and Post-Deployment Periods

The benefits from Edison SmartConnect™ begin to occur in the early stages of full scale deployment in 2008 and continue for the duration of the Post Deployment period through 2032. These benefits are presented below as either Operational Benefits or Demand Response benefits.

1. Operational Benefits

Operating benefits are primarily those operating expenses that SCE expects to avoid after the full deployment of Edison SmartConnect™ and over the life of the new infrastructure. SCE estimates Edison SmartConnect™ to provide $4.6 billion of operational benefits during the life of the project, the majority of which are expected to be realized during the Post-Deployment Period. The Table III-9 summarizes these estimated benefits and is followed by a detailed explanation of each contributing area.

Table III-9
Estimated Operational Benefits
(Millions of Nominal Dollars, Rounded)

	O&M	Capital	Totals
Meter Services	3,491.4	417.6	3,909.1
Billing Operations	422.4	0.0	422.4
Call Center	95.8	0.0	95.8
Transmission and Distribution	77.9	13.9	91.8
Other	41.7	16.5	58.1
Totals	**4,129.2**	**448.0**	**4,577.2**

a) Meter Services Operational Benefits

(1) Category Description

One of the areas significantly impacted by Edison SmartConnect™ is the Meter Services Organization (MSO), since many of the meter services now accomplished manually will be automated. These services include: (1) routine monthly manual meter reading, (3) the manual disconnection and reconnection of service (for nearly all residential meters), and (4) supervision and support associated with these manual activities. Accordingly, the vast majority of benefits of Edison SmartConnect™ come from the savings associated with automating many of the manual meter services activities currently in place today.

(2) Summary of the Meter Services Operations Benefit Estimate

To estimate the labor O&M savings for Meter Services Operations, SCE started with the recorded 2006 staffing levels for SCE's Meter Reading and Field Services organizations. Current activity levels were determined for each of the impacted areas. In the case of Field Services activities, impacts to ongoing work (additional drive time due to the reduced number of Field Services Representatives) were also evaluated. In the case of routine meter reading, SCE presently expects that this activity will be virtually eliminated with Edison SmartConnect™, so its benefit estimate includes the elimination of all meter readers and meter reader supervisors. SCE assumes that any incidental meter reading activities such as pick-up reads will be performed by remaining FSRs. Also included in this benefit estimate is the number of meter readers and field service representatives that would otherwise be added each year between 2008 and 2032 due to projected customer growth. In the case of off-cycle "pickup" reads, SCE determined the amount of Field Services labor that is currently devoted to this task. Next, SCE determined the amount of Field Services labor that is devoted to field on and off orders as well as credit-related disconnection and reconnection activity. An estimated 90 percent of this work is expected to be eliminated by Edison SmartConnect™. The combination of these analyses results in a forecast reduction in Field Services staffing after Edison SmartConnect™ meters are installed.

SCE also estimated the non-labor benefits, or savings, associated with labor reductions such as vehicle costs, worker's compensation costs, facility costs, and claims costs. These benefits are all based on recorded levels of expenses, trended forward and pro-rated based on the number of meter readers and field services representatives anticipated to be reduced as Edison SmartConnect™ is deployed.

The meter procurement benefits, including Engineering and Meter Shop activities, were handled differently than the other operational benefits described in this section. The benefits in this area come from the elimination of the need to procure electromechanical meters for new customer growth, for electronic Interval Data Recording (IDR) meters for customers requesting changes to Time-of-Use rates, and for meter failures where SCE would have had to purchase replacement meters. The total avoided material cost of the electromechanical meters that SCE expects would otherwise have been installed but for Edison SmartConnect™ are included as a benefit. This benefit is calculated based on the proposed costs of non-RTEM meter taken from the 2009 GRC annual meter capital forecast and projecting them forward.[12] SCE expects the labor required for installing growth meters will not change as result of Edison SmartConnect™.

Table III-10 shows the areas of benefits expected in SCE's Meter Services Organization operations as a result of Edison SmartConnect™.

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[12] SCE's 2009 GRC Application Notice of Intent includes these costs as "business as usual costs." Therefore they are offset as a 'benefit' in this application to avoid double counting.

Table III-10
Estimated Operational Benefits – Meter Services[13]
(Millions of Nominal Dollars, Rounded)

	O&M	Capital	Totals
Meter Reading	1,767.0	63.3	1,830.2
Field Services	1,205.4	28.0	1,233.4
Avoided Cost of Procuring Interval and Electromechanical Meters	6.3	326.4	332.6
Field Vehicles	258.0	0.0	258.0
Workers Compensation	254.8	0.0	254.8
Totals	**3,491.4**	**417.6**	**3,909.1**

(3) Meter Services Benefit Drivers

Under the category of Meter Services Organization operations, the primary drivers of benefits are the on-demand and scheduled remote-read features of the Edison SmartConnect™ meter, and the remote connect/disconnect capability of the integrated service switch.[14] SCE determined through the "Use Case" process undertaken in the Concept Design stage of Phase I that an integrated service switch in the meter would have numerous uses, including the automation of a significant amount of field activity.

The "retained" field services activities are those field services activities which cannot be automated (primarily installation and maintenance of the meters), and personnel in some of SCE's rural districts where a fixed minimum staffing level is needed.

In summary, the Meter Services benefits include:

- The labor otherwise required to read meters on-cycle and off-cycle, to install IDR meters for rate changes, to perform routine testing of the

[13] Includes meter reading and field services in rural areas of SCE's service territory.

[14] SCE anticipates that all Edison SmartConnect meters for electric service of 200 amps or less will have an integrated remote service connect/disconnect switch. This service switch also has load limiting capability. At this time SCE only plans to use the remote disconnect/reconnect capability on residential accounts because only a subset of commercial (GS-1) accounts are single phase and under 200 amps and would have the service switch in the meter. The 200-amp criteria include approximately 93% of SCE's service accounts.

existing meter population for a period of time prior to replacement of the existing meters with Edison SmartConnect™ meters, and to perform field disconnect and reconnect activities.

- The pensions and benefit expenses associated with that labor.
- The vehicle expenses, workers' compensation expenses, claims expenses, and facility expenses associated with that labor.
- The elimination of procuring electromechanical meters for new business, IDR meters for rate changes, and failure replacements.

b) Billing Benefits

(1) Category Description

Billing benefits primarily consist of improvements in the efficiency of the billing process, improvements in SCE's working capital requirement, and reductions in O&M expenses.

(2) Summary of the Billing Benefits Estimate

Billing operations provide timely and accurate billing services to SCE's 4.8 million customers. In 2006, SCE's back office systems issued over 56 million customer-billing statements. SCE also processes nearly two million manual billing exceptions annually. Implementation of Edison SmartConnect™ is expected to allow vast improvements in billing exception processing.

The largest component of billing benefits will come from reductions in SCE's working capital. Working capital will reflect reductions in unbilled revenue from Summary Accounts and a reduction in bad debt expense due to more rigid enforcement of SCE's disconnect policies. Summary Billing process efficiencies will come from the ability to synchronize billing reads for those accounts, thus virtually eliminating unbilled revenue for these accounts. Summary Billing provides a convenient billing service which allows the customer to receive just one bill for their energy consumption at multiple locations. Presently, SCE reads electric meters in geographic sequence within individual service districts. Summary Billing accounts may have individual service accounts located in different routes, cities, districts, and counties – making it impractical and costly to obtain those reads in a coordinated fashion. As a result, one service account may be read on the first day of each month, but that service account remains unbilled until the final service account on the Summary Billing statement is read, which may be the 10th day of the month or the 20th day. Upon full deployment of Edison SmartConnect™ SCE will be able to read and bill a customer for all of their accounts on the same day, which will reduce billing and payment lag, reduce the Accounts Receivable balance, and therefore reduce working capital.

Additional, working capital reductions will result from reductions in bad debt expense because of SCE's proposed prepayment service. SCE's "Use Case" process[15] identified an opportunity to offer prepayment services as a result of the remote connect/disconnect and on-demand meter reading functionality of the Edison SmartConnect™ meter. SCE expects that some customers facing difficulty establishing credit or meeting the utility's deposit requirements, or those on fixed incomes would choose the prepayment service. The prepayment service would result in two major benefits to SCE: (1) an improvement in cash flow (working capital), as electricity would be paid for prior to consumption instead of afterward; and (2) a reduction in bad debt expense, as SCE anticipates customers most at-risk for write-off would enroll in this service.

Another Billing benefit associated with bad debt expense reduction arises from SCE's ability to enforce its existing disconnect policies more rigorously. At present, field disconnect orders are not scheduled on Fridays, Saturdays or Sundays,[16] and are prioritized in the work schedule after other customer related work on the other four weekdays. The cost of a field visit to disconnect service is not trivial, so SCE does not typically disconnect for balances below $30. As a result, less than half of warranted disconnects are actually performed. With Edison SmartConnect™ remote connect/disconnect capability, SCE can automatically disconnect service when warranted under SCE's tariffs.

Finally, SCE anticipates some labor savings in billing operations. The Edison SmartConnect™ system will provide more accurate billing data, more timely completion of on

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15 The "Use Case" process was a Phase I activity to identify the potential uses for AMI.

16 SCE's tariffs provide for higher reconnection charges on weekends. As a matter of policy, SCE does not wish to force its customers to pay the higher weekend-reconnection charge, which prevents disconnect work Friday-Sunday.

and off orders, and improved data validations provided by the new Meter Data Management System, resulting in reduced billing exceptions. Currently, SCE manages and manually performs over 1 million service changes each year, due to customers moving. Most if not all of these services changes can be automatically performed given the remote connect/disconnect capability of the new meters. This reduces the likelihood of inconsistencies in customer in-service and out-of-service dates, resulting in reduced need for exception processing.

Table III-11 details the estimated billing benefits, in nominal dollars, resulting from reductions in bad debt expenses, improvements to cash-flows, and reductions in billing O&M expenses.

Table III-11
Estimated Operational Benefits – Billing Operations
(Millions of Nominal Dollars, Rounded)

	O&M	Capital	Totals
Cash Flow Improvement	230.0	0.0	230.0
Bad Debt Reduction	91.2	0.0	91.2
Billing Exceptions Reduction	101.2	0.0	101.2
Totals	**422.4**	**0.0**	**422.4**

(3) Billing Benefit Driver

The primary driver for billing related benefits is the prepayment services, which SCE expects to begin offering in the Post Deployment Period. SCE estimates that there is more than 8% of SCE's residential customers that will opt for the prepayment service. This estimate is based on results to-date from Salt River Project,[17] consumer trends in other service industries, and socioeconomic trends for SCE's customer bases. SCE expects that its residential customer adoption of prepayment will ramp-up over time as customers become accustom to this new method of payment and its benefits such as improved budgeting, ease of direct automated payments and their natural energy conservation behavior which can reduce their overall energy costs. This driver affects both the bad debt reduction and the cash-flow improvement benefit estimates, as discussed above.

17 Based on interviews conducted in 2006 with Salt River's Prepayment Project team members.

The second strong driver of billing related benefits is the cash flow improvements anticipated from reducing the amount of unbilled revenue from Summary Billing accounts. Because this cash flow would accrue to working capital, which is a component of rate base, SCE has valued this cash flow improvement at the same long-term cost of capital used to calculate the revenue requirement impact of the Edison SmartConnect™ business case, and to discount the cash flows to ratepayers.

SCE has used recorded data on its Summary Billing accounts to determine the total revenue, as well as the average "lag," for its existing accounts. In addition, while Summary Billing revenue was assumed to grow at the rate of overall customer growth, no growth in the proportions of service accounts on Summary Billing was assumed.

SCE has consistently used its long-term cost of capital throughout this case to discount costs and benefits alike. Since any change in Summary Billing lag or prepaid service payments would flow directly to SCE's working capital accounts, and these accounts are included in the calculation of rate base in each General Rate Case, this rate is appropriate to use to value the benefit of accelerating customer payments for electric service.

c) Call Center Benefits

(1) Category Description

The primary call center benefit will be a reduction in O&M expenses resulting from advanced capabilities of Edison SmartConnect™.

(2) Summary of the Call Center Benefits Estimate

This section summarizes the call center benefits, in nominal dollars, resulting from Edison SmartConnect™. SCE's call centers received approximately 13.4 million calls in 2006. A portion of these calls were handled by automated systems, however, the majority of calls (8.7 million) were handled by an SCE Call Center Specialist and outsourced business partners. Implementation of Edison SmartConnect™ anticipates significant improvements and efficiencies in each of SCE's operational areas, which SCE expects will help improve customer satisfaction. The two primary call types to be impacted by Edison SmartConnect™ are: connection related calls (*i.e.*, connect, disconnect and reconnect) and billing related calls.

First and foremost, after-hour customer calls requesting estimated service reconnection times will be reduced. Presently, SCE's Call Centers experience significant call volumes from customers waiting for service to be connected or reconnected. Since the Edison SmartConnect™ system will enable same day[18] remote service connections, these customers' calls should be virtually eliminated.

In addition, SCE forecasts a reduction in billing inquiry calls, resulting from more timely and accurate billing. Billing calls include calls related to high cost bills, delayed or first bills, and estimated or incorrect bills. High cost bills require the greatest amount of a Customer Service Representatives time to handle and complete. Edison SmartConnect™ is expected to reduce this need by helping to empower customers to manage their electricity usage and costs. Edison SmartConnect™ is expected to reduce customer calls pertaining to delayed bills. Delayed bills are primarily caused by inconsistent meter reads, lack of access to meters (locked out), no-reads, inaccurate reads, or inability to read meters due to safety concerns. Edison SmartConnect™ is also expected to virtually eliminate estimated meter reads because data will be transmitted electronically.

Table III-12 details the estimated call center benefits, in nominal dollars, resulting from reductions in call lengths and volumes.

Table III-12
Estimated Operational Benefits – Call Center
(Millions of Nominal Dollars)

	O&M	Capital	Totals
Billing Inquiry Reductions	23.1	0.0	23.1
Service Restoration Inquiry Reductions	72.7	0.0	72.7
Totals	**95.8**	**0.0**	**95.8**

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[18] Safety considerations will require that customers who make satisfactory payment arrangements must then confirm the premises are safe before the meter can be energized. This may take the form of a second customer call or other means of confirmation.

(3) Call Center Benefit Drivers

The Call Center benefits are driven mainly by the Edison SmartConnect™ capability to perform service connections in near-real time, thus eliminating customer callbacks. Service reconnection capability is driven by the remote connect switch in the Edison SmartConnect™ meter as well as the system's ability to translate a call center specialist's keystrokes into a meter command, and transmit it to the meter. Benefits are also driven by the amount of data and clarity of presentation on customers' bills as well as on SCE's website. Customers that understand their bill based on information contained on the bill, or through information provided on SCE's website are less likely to contact one of SCE's call centers.

The design of the Edison SmartConnect™ system will assure that nearly all reconnect transactions can be completed with a single phone call, or with a second "confirmation" call from the customer. Thus, the labor associated with these reconnection calls will be greatly reduced.

In addition, SCE assumes that 25 percent of the current billing inquiry call volume is related to meter reading errors, which is expected to be eliminated with Edison SmartConnect™ deployment. Thus, the call center benefit from improved reading accuracy is 25 percent of the current volume of billing inquiries.

d) Transmission and Distribution

(1) Category Description

Transmission and Distribution Business Unit (TDBU) expects to experience benefits in two of its operational areas: TDBU Engineering and TDBU Operations, as a result of Edison SmartConnect™ enabled demand response capabilities.

(a) TDBU Engineering

As part of its core operations, TDBU Engineering is responsible for planning, designing and implementing the ongoing capital improvements required for maintaining the electrical grid within SCE's service territory. These activities are critical for supporting SCE's responsibility for delivering service reliability for its customers as mandated by the Commission. The related maintenance and expansion of SCE's grid is generally due to customer growth or the need to replace equipment at the end of its useful life. Peak demand is the primary independent variable in designing the appropriate transformers, substations, wires and other materials required for maintaining a reliable transmission and distribution infrastructure. Based on the expected reductions in peak demand due to Edison SmartConnect™ enabled demand response programs, SCE expects to be able to defer some of these maintenance related capital improvements during the life of Edison SmartConnect™. These deferred maintenance cost savings are included as demand response benefits.

(b) TDBU Operations

TDBU Operations is responsible for servicing the components of SCE's grid infrastructure on an ongoing basis. In addition, TDBU Operations also provides the labor and expertise required to fulfill emergency repairs to replace unexpected failures within the grid. Most of these failures are related to transformer failure, which may occur for a variety of reasons (*i.e.*, overloading, manufacturing defects, vandalism, *etc.*). The costs associated with emergency repairs are generally more expensive because they often require overtime for SCE's crews.

Transformer loadings are currently calculated by associating individual meters with transformers in a database and then using loading factor estimates to translate monthly cumulative kWh usage into a "peak load" estimate. With Edison SmartConnect™, actual hourly kWh usage can be used to identify overloaded transformers, which can then be scheduled for replacement on a more proactive versus reactive basis, thus decreasing expensive emergency repairs in TDBU Operations.

Another way Edison SmartConnect™ benefits TDBU Operations is a significant reduction of false "no-power" service calls. At present, SCE's call centers have no way to verify if a meter has power when customers call about power outages. Many times, the call centers will notify TDBU Operations to send a troubleman to the customer's premise only to find that the meter is in fact energized, and the problem is on the customer's side of the meter, thus beyond SCE's jurisdiction. With Edison SmartConnect™, the call center staff will be able to send a signal to the meter and verify whether the meter is energized while the customer is on the phone. As a result, false "no-power" service calls can be virtually eliminated with Edison SmartConnect™ system wide.

(2) Summary of Transmission and Distribution Operational Benefit Estimate

Table III-13 shows the operational benefits SCE expects from reduced overtime costs for emergency transformer repairs and reduced field visits for “no-power” calls, as a result of Edison SmartConnect™.

Table III-13
Estimated Operational Benefits – Transmission and Distribution
(Millions of Nominal Dollars)

	O&M	Capital	Totals
Reduced Overtime Costs for Emergency Transformer Repairs	0.0	13.9	13.9
Reduced Field Visits for "No-Power" Calls	77.9	0.0	77.9
Totals	**77.9**	**13.9**	**91.8**

(3) TDBU Benefit Drivers

The primary business case driver for avoided “no-power” calls is the pace of meter deployment, as these benefits ramp-up in proportion to the number of customers whose meters can be checked prior to sending a troubleman. The primary business case driver for transformer loading benefits is the completion of meter deployment, as transformer loading analysis cannot reasonably be upgraded until all Edison SmartConnect™ meters have been activated.

The number of “no-power” calls is currently estimated at 65 per day, and these customer visits require one hour of labor for each call. Eliminating unnecessary field visits related to these calls will reduce labor costs.

The difference between replacing a transformer during normal work hours and replacing it on overtime is approximately $1,300. While no predictive maintenance system is perfect, SCE believes that with full deployment of Edison SmartConnect™, together with the development of a new predictive transformer loading replacement program, overtime costs associated with responding to 50 percent of the approximately 1,700 x 0.75 transformer failures per year can be avoided.

In summary, the TDBU operations benefits include:

- Reduced labor otherwise required to respond to customer "no-power" calls, where the meter is actually energized.
- Reduced overtime labor associated with replacing overloaded transformers after they fail.
- Reduced pensions and benefit expenses associated with that labor.
- Reduced vehicle expenses associated with that labor.

e) Other Benefits

(1) Category Description

The Other Benefits arising from Edison SmartConnect™ are expected to occur related to the elimination of the existing Customer Data Acquisition System (CDAS) and from the availability of near real-time system load data that is expected to improve the forecasting capabilities of the Energy Supply and Management organization.

(2) Summary of the Other Benefits Estimate

Table III-14 breaks down the estimated contributions of Other Benefits.

Table III-14
Estimated Operational Benefits – Other
(Millions of Nominal Dollars)

	O&M	**Capital**	**Totals**
Energy Supply and Management	15.9	0.0	15.9
Back Office Systems	25.8	16.5	42.3
Totals	**41.7**	**16.5**	**58.1**

(3) Other Benefit Drivers

The load forecasting benefits are based on power procurement cost savings that are expected to result from an assumed increase in forecasting accuracy. This improvement in load forecasting accuracy results from replacing load-profile sample data with actual interval data for all SCE customers. The expected decommissioning of the CDAS system will result in the elimination of costs to maintain the system and associated computing devices currently supporting CDAS personnel.

2. Demand Response Benefits during the Deployment and Post Deployment Periods

A significant portion of the benefits derived from Edison SmartConnect™ is attributed to the expected demand response (DR) benefits. Edison SmartConnect™ is aimed at supporting the Commission's energy policy objectives, especially with regard to enhancing the state's demand response capabilities. Exhibit SCE-4 is dedicated to detailing the tariffs and programs expected to be implemented as a result of Edison SmartConnect™. Exhibit SCE-4 also provides details about the underlying assumptions for calculating the expected avoidance of the energy and capacity costs from Edison SmartConnect™ enabled demand response. The following sections summarize SCE's expectations of benefits for Edison SmartConnect™ enabled demand response capabilities.

a) Category Description

Demand response benefits accrue because Edison SmartConnect™ enables dynamic pricing, better customer information about usage and energy costs and load control programs enhanced by two-way communications. These attributes contribute to providing SCE customer generation and energy procurement cost savings as well as savings from transmission and distribution infrastructure capital deferrals. The transmission and distribution benefits were described in Section 1.d above. The energy procurement related benefits are classified as O&M (ERRA) benefits and described below.

b) Summary of the Demand Response Benefit Estimate

Demand Response benefits fall into two major groups: (1) Price Response, where customers take actions as a result of adopting a Time-of-Use (TOU) or Critical Peak Pricing (CPP) tariff, and (2) Load Control, where the Edison SmartConnect™ system activates one or more customer-premise devices in response to a utility signal to curtail load, for economic or system stability purposes, or customers respond to a pay-for-performance rebate program.

Table III-15 shows forecast demand response driven benefits for avoided capacity and energy costs resulting from the five demand response components. The time-differentiated tariffs, TOU and CPP, represent 14 percent of these estimated savings. The demand response programs, PCT and PTR, are expected to provide 63 percent of these estimated savings. The remaining 23 percent of these estimated savings is expected to be derived from growth in energy conservation by customers as a result of energy information from the Edison SmartConnect™ system via the internet. Additional conservation may result from access to near real time information from the meter to customer's in-home display enabled by the HAN interface.

In addition, SCE expects an additional $221.5 million of deferred capital benefit in TDBU engineering as a result of Edison SmartConnect™. The total estimated demand response benefits over the project life are forecast at $3,008.8 million.

Table III-15
Estimated Demand Response Benefits
(Millions of Nominal Dollars)

	O&M	Capital	Totals
Avoided Capacity and Energy Costs:			
TOU	190.4	0.0	190.4
CPP	186.6	0.0	186.6
PCT	1,126.8	0.0	1,126.8
PTR	647.2	0.0	647.2
Conservation Effect	636.3	0.0	636.3
TDBU Deferred Capital	0.0	221.5	221.5
Totals	**2,787.3**	**221.5**	**3,008.8**

c) Demand Response Benefit Drivers

There are numerous regulatory and business case drivers for Demand Response benefits, including the number of customers who will adopt TOU or CPP; the dollar value of avoided energy and capacity purchases; the applicability of AB 1X to default time-differentiated rates; the amount of energy customers conserve monthly or annually due to AMI enabled information about their usage and costs; and the level of responsiveness (or peak demand reduction) from customers who adopt time-differentiated rates.

There are also benefits related to sub-transmission and distribution related capital deferral resulting from all demand response tariffs and programs (noted as TDBU Deferred Capital in Table III-15). Capital deferral of upgrades to existing distribution facilities provides a significant cash flow benefit to SCE. SCE assumed that 20 percent reduction in projected megawatt (MW) growth in peak demand could potentially result from Edison SmartConnect™ enabled demand response capabilities. The deferred capital is based on a 10-year average of estimated sub-transmission and distribution capital costs of approximately $412,000 per MW. Exhibit SCE-4 details the expected MW reduction as a result of Edison SmartConnect™ along with the related assumptions and drivers.

Starting in the Deployment Period, SCE assumes that it will offer the dynamic rates and demand response programs discussed in detail in Exhibit SCE-4. The demand response benefits are highly dependent on the specific terms and conditions of the tariffs, so the primary regulatory driver of Demand Response benefits is the degree to which the approved tariffs match those proposed in the full deployment application.

SCE uses the results from the Statewide Pricing Pilot (SPP) to determine both the level of customer adoption of time-differentiated rates, as well as the degree of price-responsiveness of those customers who adopt the rates.[19] The SPP experiment was conducted over a two-year period and may not represent the full effect of long term availability of pricing information and time-differentiated tariffs. For example, academic literature on price elasticity of demand demonstrate that price elasticity and energy conservation from time-differentiated tariffs are generally higher over the long term than in the short run. Over the long term, customers make investments in their building structures (*e.g.*, energy-efficient windows and better insulation) as well as lighting equipment and appliances commensurate with their exposure to peak period pricing. Although the load impacts of dynamic pricing in the long term should be higher than in the short run, SCE has not included the benefits from this effect at this time.

SCE's approach to achieving significant demand response relies on the Peak Time Rebate, pay for performance program, direct load control programs for residential customers, and TOU and (CPP) rates for residential and commercial and industrial (C&I) customers.

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[19] The Statewide Pricing Pilot (SPP) was a pricing research project designed to estimate the average impact of time-varying rates on energy use by rate period for residential and small commercial and industrial customers. The SPP was authorized in D.03-03-036.

d) Demand Response Benefit Assumptions

The Commission and CEC believe that a goal of price-responsive demand of 5 percent of system peak is achievable. With Edison SmartConnect™ this goal can be realized as well as additional demand response from load control. A recent study by the Brattle Group for the CEC found that the technical potential for demand response in California is nearly 25 percent of system peak.[20] The study also found that the market potential for demand response in California is about 12 percent. SCE's proposed demand response approach would achieve demand response of approximately 8 percent, two-thirds of the full market potential by 2013. It is SCE's view that to achieve the market potential for demand response, a portfolio of offerings including dynamic pricing and incentive-based load control is required. Edison SmartConnect™ enables new approaches to both by evaluating the availability of load reductions from operating air conditioning as well as by enabling a pay for performance approach to incentives.

SCE proposes that significant demand reduction can be achieved with a Peak Time Rebate (PTR) approach where the customer receives a rebate for reducing usage during the peak time of a critical day. Studies for the City of Anaheim and for San Diego Gas and Electric found that PTR could achieve results similar to Critical Peak Pricing (CPP) observed in the Statewide Pricing Pilot (SPP).[21] PTR could be offered to all customers, a significant advantage over dynamic pricing rates which require rate structures and enrollment approaches compliant with AB1-X. AB1-X substantially reduces the potential for dynamic pricing by excluding a substantial portion of customer usage from rate changes.

SCE also proposes to improve on its successful track record with air conditioning load control by offering a smart communicating thermostat based program that would provide two-way communications to enable existing load availability and easy customer event override. The SCE smart

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[20] CEC draft report, California's Next Generation of Load Management Standards, Ahmad Faruqui and Ryan Hledlik, May 2007, CEC-200-2007-007-D.

[21] *See* A.05-03-015, Errata to Chapter 6, Demand Response Benefits, July14, 2006 Amendment, by Dr. Stephen S. George on behalf of SDG&E, and Residential Customer Response to Real-Time Pricing: The Anaheim Critical-Peak Pricing Experiment, Frank Wolak, Center for the Study of Energy Markets (CSEM), May 2006.

thermostat program[22] would supplement the existing load control switches already installed at the time of smart meter deployment. The SCE smart thermostat program will require the use of Title 24 compliant programmable communicating thermostats PCTs.

SCE would move Commercial and Industrial (C&I) customers above 20kW to Time of Use (TOU) dynamic pricing on a default basis with voluntary opt in to CPP rates. The SPP found that C&I greater than 20kW can provide significant demand response.

SCE believes that customers can dramatically change peak usage behavior if given the proper pricing signals, incentives, enabling technologies and tariffs and programs that make it easy to do so. SCE has largely relied on assumptions and methodologies adopted in the AMI applications by PG&E and SDG&E as well as applicable literature. SCE has not attempted to include all potential demand response benefits leaving some room for potential increases, as noted in the assumptions below:

The overarching assumptions in the analysis of Demand Response benefits include:

(1) Meters and Communications

- All customers below 200kW will be equipped with Edison SmartConnect™ meters per the deployment schedule.
- Residential meters will provide at least hourly interval data, collected each day and available for customer viewing next day. Commercial and industrial customer meters will provide 15 minute interval data.
- Two-way communications with the meter and any associated PCTs will be enabled.

[22] SCE's smart thermostat program may either involve rebates to customers who choose the thermostat to purchase through retailers or SCE providing thermostats to customers to facilitate the process. In either event, SCE will not own the thermostat.

(2) Tariff Enrollment Assumptions

- Customer enrollments were estimated using the Momentum Market Intelligence model developed in the Statewide Pricing Pilot program. The model uses bill impact assessments to determine enrollment preferences.

- All residential customers will be eligible to receive Peak Time Rebates (PTR) for qualifying load reductions on critical days. The average residential customer awareness rate for PTR critical day events is assumed to be 50 percent. For example, for any given PTR critical event day, 50 percent of all residential customers will be aware that rebates for load reductions are available for that day.

- C&I customers above 20kW in demand will be defaulted to a TOU rate with the option to choose a CPP-F rate. The default TOU participation rate was estimated to be 51 percent for medium C&I customers.
- Some C&I customers above 20kW in demand will voluntarily enroll in CPP-F rates when they receive a SmartConnect™ meter. The opt-in CPP participation was estimated to be 25% of all medium C&I customers.

(3) Load Control Program Assumptions

- Title 24 compliant PCTs will be available and installed in new homes and HVAC retrofits requiring permits beginning in 2009.

- SCE will offer and market a load control program to customers based on Title 24 compliant PCTs that interface with Edison

SmartConnect™ meters and 25 percent are assumed to enroll. Customers will be paid an incentive to participate.

- SCE will discontinue growth of the current Air Conditioning Cycling Program (or Summer Discount Plan (SDP)) in 2009 which is expected to have over 300,000 enrollees by then. The SDP program will continue with moderate attrition. Beginning in 2009, the SDP program will be changed for customers equipped with Edison SmartConnect™ meters. The program will be economically dispatched more often for shorter durations to shave the system peak rather than only dispatched for reliability purposes.

- An SCE smart thermostat program (using Title 24 compliant PCTs) will be offered, beginning in 2009, to residential customers who have Edison SmartConnect™ meters and existing central air conditioning but are not required to have Title 24 compliant PCT installations. A marketing program will initially enroll 60,000 customers per year until approximately 250,000 customers are enrolled. Enrollment at 250,000 will be maintained. SCE will provide eligible customers equipment and installation rebates up to $125 per central air conditioner. Customers will also be paid an incentive to participate in load control events.

- Total SCE residential enrollment in load control will reach approximately 25 percent of customers with central air conditioning.

- The present analysis is conservative in that it does not include load control programs for C&I customers.

(4) Load Reduction Impacts

- SPP results for price elasticity and the Charles River Associates PRISM model are used to determine load reductions for SCE's customers.[23]

- No increase in prices elasticity for long term effects is included at this time as the SPP did not address long-term elasticity.

- An energy conservation effect is included due to mass implementation of dynamic rates and the widespread availability of pricing and other information to customers about their energy usage and costs.

(5) Energy Information Assumptions

- Customers receiving price signals from tariffs and load control programs will be much more aware of their usage and costs, by various means. That awareness could result in significant energy conservation.
- Studies have shown the energy conservation effect of price and usage information from advanced metering could be as much as 20 percent.[24] SCE has assumed the conservation effect to be 1 percent of total consumption per year.

(6) Procurement Benefit Assumptions

- SCE's forecast for avoided capacity and energy costs is included. The forecast relies on a Combustion Turbine (CT) proxy. The capacity

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[23] Impact Evaluation of the California Statewide Pricing Pilot, Final Report, March 16, 2005, prepared by Charles River Associates.

[24] *See* PUBLIC UTILITIES FORTNIGHTLY MARCH 2007 at p. 42, *citing Direct Energy Feedback Technology Assessment for Southern California Edison Company*, prepared by Lynn Fryer Stein and Nadav Enbar, EPRI Solutions, March 2006 (noting that there is a risk of self-selection bias toward those more interested in conservation.) *See also* Ontario Energy Board Smart Price Pilot, Final Report July 2007, p. 7, estimating energy conservation to be at 6%.

value for CPP and load control is discounted due to their limited availability compared to a CT.

- Includes avoided reserves and distribution losses.

(7) Transmission and Distribution Capital Deferral Assumptions

- The Transmission and Distribution assumptions include a benefit from the deferral of capital expenditures for transmission and distribution due to reduction in local system peak demand from Edison SmartConnect™ tariffs and programs.

(8) Demand Response Benefits

Include:

- The avoided energy and capacity procurement (or construction) costs that would otherwise be required to serve peak load in the absence of Edison SmartConnect™-enabled load control and time-differentiated rates.
- The avoided distribution capital costs associated with system upgrades otherwise required to serve peak load in the absence of Edison SmartConnect™-enabled load control and time-differentiated rates.

IV.

SOCIETAL BENEFITS (NON-FINANCIAL)

SCE has identified a number of non-tangible, societal benefits of Edison SmartConnect™ that are important in considering the reasonableness of Edison SmartConnect™. These benefits include improvements in customer satisfaction reductions in energy theft, potential environmental benefits, and other societal benefits that create positive externalities. There may be societal benefits in the customer service improvements SCE expects from the Edison SmartConnect™'s ability to mitigate customer exposure to service interruptions, outage durations, and/or service degradation due to poor power quality. Potential societal costs include the value of lost service by customers who provide demand reductions in response to emergencies or price signals.

Because the societal benefits and costs are not quantifiable, or do not directly impact SCE's revenue requirement, they are not included in the financial assessment. Over time, however, SCE expects substantial benefits will be gained by the implementation of Edison SmartConnect™ beyond what the numbers show.

In the recent SDG&E Decision, the Commission stated, "These various benefits (and potentially others) are real, even if not quantified."[25] Appropriately, SCE describes some of these societal benefits separately below.

A. Improvement in Customer Experience

Edison SmartConnect™ is likely to improve customer experience in numerous ways. SCE has conducted primary and secondary research on its customers to better understand the nature of the experience they have with SCE. Additionally, SCE has been examining the consumer socio-economic and demographic trends in Southern California with a view to 2012. The initial results of these analyses indicate that about 69% of SCE's customers today expect more personalized service options and simple automated choices. The expected rise in

[25] D.07-04-043, p. 71.

customers with fixed incomes due to increasing population of retirement age along with as many as one million immigrants coming to Southern California by 2012 creates new demands for how SCE engages customers and provides services. The heightened awareness of environmental concerns creates the opportunity for customer engagement on energy conservation and demand response beyond the programs identified in this case. Customer feedback regarding the capabilities of Edison SmartConnect™ in focus groups conducted over the past year was that they see the opportunity to be the "smart" in Edison SmartConnect™.

B. Energy Theft

Energy theft occurs and is a cost of doing business that is borne by all ratepayers. Any reduction in energy theft from the implementation of automated meters will enable SCE to spread its revenue requirement over more energy sales, thus reducing rates. SCE anticipates that Edison SmartConnect™ will reduce energy theft in three ways. First, during deployment, SCE's vendor will be removing every existing meter and replacing it with a new solid-state meter and the installers (both SCE and contracted labor) will be trained to notice irregularities which can be investigated as potential theft. Second, the tamper detection capability of the Edison SmartConnect™ meter will virtually eliminate meter tampering as a source of energy theft as the meter will provide tamper notification which will be analyzed and potentially investigated for theft. Third, the more sophisticated Meter Data Management System is expected to allow SCE to better detect bypass and partial-bypass theft through data mining.

Any reduction in energy theft essentially reduces cross subsidization and insures that costs are billed appropriately to those utilizing the energy.

C. Environmental Benefits

There are potential environmental improvements that will result from reduced generation and from substituting more-efficient off-peak generators for less-efficient on-peak units through the use of demand response and load control. Energy conservation, based on Edison SmartConnect™ information, has a very large potential for creating significant environmental benefits. Based on conservative estimates in this case, SCE expects Edison SmartConnect™ to create an annual reduction of 365,000 metric tons of carbon dioxide or about 1,000 metric tons per day.[26]

D. Non Qualified Benefits from SmartConnect™ Functionality

Edison SmartConnect™ system has several capabilities that provide real options for future value that are not quantifiable today. For example, the meter has the ability to measure voltage at the premise and may be used for a variety of purposes, such as to support improved customer service, contribute to grid asset management and to provide feedback to customer side energy management systems. Additionally, the integrated service switch has remote load limiting capability that can be used for managing peak demand at the premise level to mitigate grid emergencies and provide a demand subscription rate option. The switch also opens on a power failure and can detect voltage on the customer side of the switch when open that provides a safety feature in the event the customer turns on a generator on their side of the meter after a power outage. This same switch can contain a randomizer to stagger the closure of the switches in an area to reduce the surge when a circuit is re-energized. These capabilities and other foundational aspects of the system continue to be explored by SCE and may become fully functional in Release 3 or beyond.

E. Improved Customer Security

Edison SmartConnect™ will improve customer security because meter readers will no longer have to physically read customers' meters by entering yards, or in more limited cases, customers' homes. In focus groups, customers identified safety and security as compelling benefits of Edison SmartConnect™. For example, some customers cited the need to put their dogs inside on meter reading days as a security issue because the dogs are kept as a theft deterrent. Additionally, other customers referred to the need to unlock doors or gates to allow

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[26] The energy procurement benefits of the demand response and conservation impacts of SmartConnect are detailed in Exhibit SCE-4, but SCE's business case does not include benefits for carbon dioxide reductions of approximately 365,000 metric tons per year due to reduced electrical generation.

meter reading as a security issue that will no longer exist. In all automating the meter reading process was seen as a significant safety and security benefit from a customer perspective.

V.

ANALYSIS OF SMARTCONNECT™ REVENUE REQUIREMENT AND RATEPAYER IMPACTS

This section describes the SmartConnect™ cost-effectiveness analysis performed by SCE that compares ratepayers' benefits from implementation of SmartConnect™ to the project costs resulting from implementation of SmartConnect™. The benefits of SmartConnect™ are the costs that ratepayers avoid as a result of SmartConnect™. Specifically, this avoided cost is the difference between what ratepayers would pay for service assuming SmartConnect™ is fully implemented, and what they would pay assuming no implementation through 2032.

The following equation sets forth the benefit-to-cost ratio for SmartConnect™:

$$\text{Benefit-to-Cost Ratio} = \frac{\text{PV of Ratepayer Benefits}}{\text{PV of Ratepayer Costs}}$$

The 2007 present value of the revenue requirement (PVRR) of Ratepayer Benefits for SmartConnect™ was calculated at $1,736 million. The 2007 PVRR of deployment costs was calculated at $1,627 million. The resulting benefit-to-cost ratio is 1.07 to 1. SCE found that ratepayer benefits exceed costs by $109 million.

A. Methodology

SCE's cost-effectiveness evaluation of SmartConnect™ is a life-cycle benefit-to-cost analysis from a ratepayer perspective. SCE's life-cycle perspective measures total benefits and costs from 2007-2032. Because benefits and costs occur over many years, SCE used net present value (NPV) analysis to bring all benefits and costs to the base year of 2007. Measuring benefits and costs from a ratepayer perspective means that SCE valued all benefits and costs using the revenue requirement that ratepayers would incur or avoid.

1. Benefit-To-Cost Analysis

NPV is the discounted monetized value of expected net benefits (*i.e.*, benefits minus costs). NPV assigns monetary values to benefits and costs, discounts future benefits and costs using an appropriate discount rate, and subtracts the sum total of discounted costs from the sum total of discounted benefits. Discounting benefits and costs transforms gains and losses occurring in different time periods to a common unit of measurement. The ratio of the NPV of benefits to the NPV of costs is the benefit-to-cost ratio. Values above 1.0 indicate projects which benefit ratepayers.

In this analysis, the benefits of SmartConnect™ are the difference between avoided costs from SmartConnect™ and the Post Deployment costs (post 2012) ratepayers would incur from SmartConnect™ implementation. Table V-16 shows the PVRR for ratepayer net benefits.

2. Revenue Requirement Model

a) Purpose of the Revenue Requirement Model

To quantify ratepayers' benefits resulting from SmartConnect™, it is necessary to determine the avoided and incremental costs that ratepayers will incur from 2007-2032 due to SmartConnect™ Implementation. To do this, SCE converts the avoided and incremental costs into the ratepayers' revenue requirement.

To quantify ratepayers' SmartConnect™ project costs (2007-2012 deployment costs[27]), it is necessary to determine the annual payments equivalent to the SmartConnect™ deployment costs. Therefore, SCE also converts the deployment costs into a revenue requirement.

Because ratepayers pay revenue requirements over a number of years, to compare different revenue requirements, it is necessary to put them on a consistent basis relative to the timing of payments. This conversion to a consistent basis is called Present Value (PV) analysis. For the SmartConnect™ benefit-to-cost analysis, SCE converted each revenue

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[27] Deployment costs include pre-deployment costs.

requirement into a single PV that assumes 2007 as the base year.[28] Therefore, the purpose of the revenue requirement model is two-fold. First, the model converts SCE's costs (either avoided or expected) into a revenue requirement which ratepayers would expect to pay. Second, the model changes these streams of revenue requirements paid over a number of years into a single PV.

Table V-16 lists the PV of ratepayers' benefit due to the AMI.

Table V-16
Ratepayer PVRR of Benefits
Resulting from SmartConnect™ Implementation
($ In Millions, Rounded)

Ratepayer Avoided Costs from SmartConnect™ Implementation	
Capital Savings	$334
|O&M Savings	$1,036
Demand Response Savings	$706
Total: Ratepayer Avoided Costs from SmartConnect™ Implementation	$2,076
Post Deployment Costs from SmartConnect™ Implementation	
Incremental Capital	$123
Incremental O&M	$217
Total: Post Deployment Costs	$340
Ratepayer benefit	$1,736

b) Overview of Revenue Requirement Model

As described above, SCE used the revenue requirement model to: (1) convert costs incurred by the utility into a revenue requirement paid by ratepayers; and (2) translate the revenue requirement into a PV for comparison purposes. The testimony below describes the methodology for each of these tasks.

(1) Conversion of Costs Into a Revenue Requirement

A utility's cost of service, or revenue requirement, is all of its operating expenses plus a return on its investment. Therefore, the revenue requirement equals the sum of all costs necessary to meet its obligation to serve. The following formula expresses this revenue requirement:

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[28] Present value calculated using SCE's 10% incremental cost of capital. If SCE were to use its 2007 authorized cost of capital as a discount rate instead of its incremental cost of capital (similar approach of SDG&E), SCE's net benefits of Edison SmartConnect™ would increase to $241 million.

Revenue requirement = Operation and Maintenance (O&M) expense +
Depreciation expense +
Tax expense +
Return on investment

O&M expense is the cost of routine work that SCE performs to supply electric service during the course of a year. O&M expenses include labor, materials, supplies, and variable administrative and general (A&G) expenses.

Depreciation expense is the charge against earnings that SCE takes each year to allow for the recovery of an investment (including removal costs) over its useful life.

Tax expense includes taxes based on income, miscellaneous taxes, and Ad Valorem (property) taxes on incremental investment.

Return is the cost of capital SCE incurs to finance its long-term investments. SCE multiplies the rate of return by its long-term investment to calculate its return. For the SmartConnect™ benefit-to-cost analysis, SCE used its incremental cost of capital. SCE's long-term investment is its Rate Base. The following formula illustrates the calculation of Rate Base:

Rate Base = Fixed capital - Reserves

Fixed capital is the sum of the plant in service, intangible plant including capitalized software, and plant held for future use. Reserves include accumulated depreciation, accumulated amortization, and accumulated deferred taxes.

(2) Translate the Revenue Requirement into a Present Value

As previously discussed, once SCE has calculated the revenue requirements for each cost component, it is necessary to put them on a consistent basis relative to the timing of the ratepayers' payment. Table V-17 lists the annual revenue requirements for each of the cost components used in the benefit-to-cost analysis. Section b1 above, describes the calculation of these revenue requirements. Table V-18 below compares the sum of each revenue requirement to the PV of each revenue requirement.

Table V-17
Summary of SmartConnect™ Revenue Requirement
($ In Millions, Rounded)

SMARTCONNECT Revenue Requirement Summary Table										
	POST DEPLOYMENT COSTS			AVOIDED COSTS						
	CAPITAL	O&M	Total Costs	O&M Savings	Capital Savings	Demand Response	Total Avoided Costs	**Ratepayer Benefits**	**Deployment Cost**	**Net Benefit**
2007	-	-	-	-	-	-	-	-	27,251	(27,251)
2008	-	-	-	1,219	-	-	1,219	1,219	69,374	(68,154)
2009	-	-	-	8,254	2,636	4,487	15,378	15,378	154,438	(139,060)
2010	-	-	-	29,265	7,298	26,889	63,453	63,453	241,915	(178,462)
2011	-	-	-	61,353	12,555	48,004	121,912	121,912	293,246	(171,334)
2012	-	-	-	90,228	20,512	66,497	177,237	177,237	322,412	(145,175)
2013	2,989	57,766	60,755	118,134	35,755	77,944	231,833	171,078	234,464	(63,386)
2014	7,548	48,345	55,892	125,606	45,378	84,703	255,687	199,795	215,834	(16,039)
2015	11,468	40,440	51,908	132,192	50,636	90,442	273,270	221,362	202,153	19,209
2016	15,612	32,803	48,415	139,772	52,663	93,891	286,327	237,911	190,917	46,994
2017	18,638	33,950	52,588	148,230	56,014	98,874	303,118	250,530	180,832	69,698
2018	20,643	32,844	53,487	155,959	56,512	104,027	316,499	263,011	171,423	91,588
2019	21,931	33,747	55,678	164,528	57,647	109,798	331,973	276,295	162,087	114,208
2020	24,167	35,529	59,696	172,980	58,891	114,687	346,558	286,862	152,725	134,137
2021	25,857	36,238	62,094	182,156	60,186	120,539	362,881	300,787	143,330	157,457
2022	27,980	37,331	65,311	190,410	61,798	126,584	378,791	313,480	133,908	179,572
2023	30,065	38,753	68,818	199,238	64,271	132,807	396,316	327,498	124,461	203,037
2024	33,550	38,583	72,133	208,160	65,841	139,229	413,230	341,097	115,045	226,053
2025	36,051	40,106	76,156	217,666	67,552	145,808	431,026	354,870	105,714	249,156
2026	37,561	42,146	79,707	227,850	69,500	152,635	449,984	370,276	96,475	273,801
2027	38,710	44,021	82,731	238,181	72,055	159,696	469,931	387,201	87,326	299,875
2028	41,788	44,165	85,953	248,568	76,058	166,953	491,578	405,626	75,016	330,610
2029	45,919	45,257	91,176	260,193	78,186	175,476	513,855	422,679	48,872	373,807
2030	53,008	46,018	99,026	271,729	82,425	183,173	537,328	438,302	21,781	416,521
2031	68,056	47,739	115,795	284,089	90,395	192,291	566,775	450,980	(29,599)	480,580
2032	90,465	50,183	140,649	295,726	94,930	200,493	591,148	450,500	(992)	451,492
Total	652,004	825,964	1,477,968	4,171,688	1,339,692	2,815,927	8,327,307	6,849,339	3,540,407	3,308,932
2007 PV	123,453	217,149	340,602	1,036,067	334,089	706,165	2,076,321	1,735,719	1,627,024	108,695

Table V-18
Revenue Requirement Resulting from SmartConnect™ Implementation
($In Millions, Rounded)

	Sum of Annual Revenue Requirement	PVRR
Ratepayer Avoided Costs from SmartConnect™ Implementation		
Capital Savings	$1,340	$334
O&M Savings	$4,172	$1,036
Demand Response	$2,816	$706
Total: Ratepayer Avoided Costs from SmartConnect™ Implementation	$8,327	$2,076
Post Deployment Costs from SmartConnect™ Implementation		
Incremental Capital	$652	$123
Incremental O&M	$826	$217
Total: Post Deployment Costs	$1,478	$340
Ratepayer Benefit	$6,849	$1,736
SmartConnect™ Deployment Costs	$3,540	$1,627
Net PVRR		$109

The difference between the sum of the annual revenue requirements and the PV of the revenue requirements is due to the timing of the ratepayers' payments. The earlier the ratepayer pays the revenue requirement, the higher the PV. The following formula translates the revenue requirement into the PV:

$$PV = \frac{RR_1}{(1+r)} + \frac{RR_2}{(1+r)^2} + \ldots + \frac{RR_n}{(1+r)^n} = \Sigma \frac{RR_i}{(1+r)^i}$$

where:

RR - represents the revenue requirement costs.

i - Represents the year in which ratepayers pay the revenue requirement.

n - Represents the year considered.

r - Represents the discount rate (the discount rate quantifies the willingness of ratepayers to exchange present costs and benefit for future costs and benefits).

B. Benefit-To-Cost Ratio Results

Figure V-1 below shows how SCE calculates the benefit-to-cost ratio for SmartConnect™ in three representations of the same equation. Each representation of the equation provides more details of the data utilized in the calculation. Equation No. 1, shows at the most summary level the benefit-to-cost ratio, comparing ratepayer benefits to ratepayer costs. Equation No. 2, in Figure III-2, shows how the ratepayer benefits are calculated by subtracting the Present Value Revenue Requirement (PVRR) of incremental operating costs from avoided costs. The result of that equation is then divided by the PVRR of SmartConnect™ project costs.

Equation No. 3 in Figure V-1 delves even more deeply into the details of determining the PVRR for avoided and incremental costs. Equation No. 3 shows that the PVRR of avoided costs are equivalent to the PVRR of capital savings, O&M savings, and demand response savings. From this PVRR SCE subtracts the PVRR of incremental operating costs. The PVRR of incremental operating costs is the PVRR of incremental capital plus the PVRR of incremental O&M. This PVRR of ratepayer benefits is then divided by the PVRR of SmartConnect™ project costs.

Figure V-1
Detailed Benefit-To-Cost Framework

1. $$\text{Benefit-To-Cost} = \frac{\text{PV of Ratepayer Benefits}}{\text{PV of Ratepayer Costs}}$$

2. $$\text{Benefit-To-Cost} = \frac{\text{PVRR of Avoided Costs - PVRR of Post Deployment Costs}}{\text{PVRR of Deployment Costs}}$$

3. $$\text{Benefit-To-Cost} = \frac{\begin{array}{c}\text{PVRR of (Capital Savings + O\&M Savings + Demand Response)}\\ \text{LESS PVRR of (Post Deployment Capital + O\&M)}\end{array}}{\text{PVRR of Deployment Costs}}$$

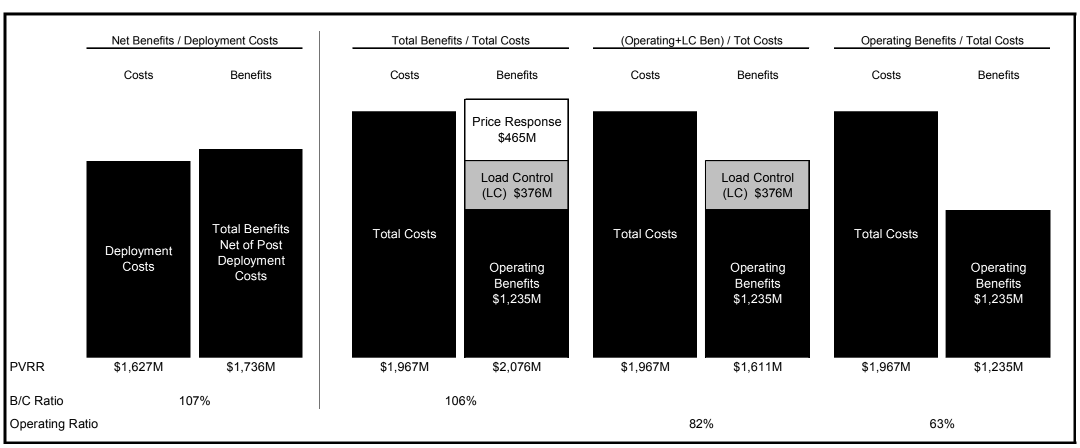
Table V-19 shows the results of SCE's benefit-to-cost calculation.

Table V-19
Benefit-To-Cost Calculation
($In Millions, Rounded)

Ratepayer Avoided Costs from SmartConnect™ Implementation	$2,076
Post Deployment Costs from SmartConnect™ Implementation	$340
Ratepayer Benefits	$1,736
Ratepayer Deployment Costs	$1,627
Benefit-To-Cost Ratio	1.07
Net Benefit	$109

SCE has also calculated the ratio of total benefits to total costs, as well as the ratio of total operational benefits, reflecting no demand response benefits to total project costs. After removing the easily-identified incremental costs of operating and promoting demand response programs; this approach produces a ratio of 63 percent. The analysis of operational plus direct load control benefits to respective cost results in a ratio of 82 percent. SCE submits that the best measure of benefit to cost ratio should include all customer demand response benefits made up of both direct load control benefits and the longer term and very real price response benefits expected to result from dynamic pricing; this results in a benefit to cost ratio of 106%. Each of these benefit-to-cost ratios is illustrated in Figure V-2.

Figure V-2
Comparison of 2007 PVRR Benefit-to-Cost Ratios for Edison SmartConnect™ Project
(Millions of 2007 Dollars)



Appendix A

Witness Qualifications

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF LISA D. CAGNOLATTI

Q. Please state your name and business address for the record.

A. My name is Lisa D. Cagnolatti, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the Director of the Customer Communications Organization

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor's degree in Chemical Engineering from UCLA and an MBA from Pepperdine University. I have over 20 years of experience in the utility industry including positions of increasing responsibility in Marketing, Environmental Affairs, Regulatory Affairs, Transmission and Distribution, and Customer Services.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of this Exhibit SCE-3 as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF BERRY L. CURRY

Q. Please state your name and business address for the record.

A. My name is Berry L. Curry, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I work in the Distribution Engineering group. Our primary responsibilities include the creation and publication of SCE's Distribution Substation Plan, which documents the projected distribution and subtransmission system load forecast, load growth and capital investment required to meet the load growth.

Q. Briefly describe your educational and professional background.

A. Bachelor of Science in Electrical Engineering, New Mexico State University, 1987. Registered Professional Engineer, State of California, E13856. I have worked in the electric utility industry continuously since 1987.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of this Exhibit SCE-3 as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF PAUL J. DE MARTINI

Q. Please state your name and business address for the record.

A. My name is Paul J. De Martini, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the Edison SmartConnect Program Director. I am responsible for managing all aspects of the AMI program feasibility, system design, development, and deployment efforts.

Q. Briefly describe your educational and professional background.

A. I hold a Master of Business Administration (M.B.A) degree from the University of Southern California and a Bachelor of Science (B.S.) degree in Applied Economics from the University of San Francisco. I also completed Certificates in Project Management from the University of California, Berkeley and Technology Management from the California Institute of Technology. I have been at Southern California Edison for about five years during which I was the IT Project Manager on AMI beginning in 2004, prior to assuming the overall program management responsibility in 2005. Relevant positions prior to joining Southern California Edison included Vice President of the Energy Strategy practice at ICF International in 2000-2002 with a focus on demand response, advanced metering and distributed generation technologies. I began my career at PG&E Corporation in both regulated and unregulated businesses for nearly twenty years. I held positions at the utility with increasing responsibility involving electric systems operations, T&D project management, and wholesale power procurement and ultimately at the unregulated subsidiary PG&E Energy Services as Vice President, Integrated Services.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of this Exhibit SCE-3 as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF PAUL KEVIN ELLISON

Q. Please state your name and business address for the record.

A. My name is Paul Kevin Ellison, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I serve as the Director of the Meter Services Organization in the Customer Service Business Unit (CSBU). This is the senior leadership position in the organization. The Meter Services Organization is responsible for all aspects of the end-to-end meter process including:

- Evaluating and monitoring the business environment
- Planning, developing, and implementing meter process improvements
- Performing meter evaluations and laboratory testing
- Planning, testing and implementing new and efficient technologies
- Meter installation, change, maintenance, assessments and compliance
- Field customer service requests, including turn-ons and turn-offs
- Routine and non-routine meter reading
- Investigating unauthorized use and recovery of revenue loss
- Ensuring the accuracy and integrity of revenue billing

Q. Briefly describe your educational and professional background.

A. I hold a Bachelors Degree in Business Administration from the University of Louisville and a Masters Degree in Business Administration from Bellarmine University in Louisville, Kentucky. In addition, I have completed a number of Executive Education programs. I have over 27 years of utility experience, the last three years with Southern California Edison Company. Prior to joining the Southern California Edison Company, I previously worked at LG&E Energy Corp (Louisville Gas and Electric Company and

Kentucky Utilities Company) where I held a number of senior management and management positions in Customer Service, Marketing, T&D Operations and Economic Development. From April 2001 until May 2004, I served as Chief Operating Officer for a Louisville, KY based Software Company and with Merrill Lynch as a Financial Advisor, focused on the small business marketplace. I began work for SCE in 2004 as the Director of the Government and Institutions group within the Business Customer Division. I have been in my current position as the Director of the Meter Services Organization since March 2006.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of this Exhibit SCE-3 as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF ERIC S. HELM

Q. Please state your name and business address for the record.

A. My name is Eric S. Helm, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. As Manager of Financial Planning and Analysis for the Customer Service Business Unit, I am currently responsible for financial modeling, project analysis, and product and service pricing for major projects within the business unit.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Arts degree in Economics from Claremont McKenna College, and an MBA with a Finance concentration from California State University at Long Beach. I joined Edison's Residential Energy Management staff in 1983, working on residential rebate and home energy survey programs. I held analyst positions in the Revenue Requirements department from 1987-89, and analyst and management positions in SCE's Treasurer's department from 1989-1996, primarily in the Investor Relations group. I have managed the CSBU Financial Planning function since 1996. I have previously testified before this Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of this Exhibit SCE-3 as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF BENJAMIN DAVID HODGES

Q. Please state your name and business address for the record.

A. My name is Benjamin David Hodges, and my business address is 2244 Walnut Grove Ave, Rosemead, CA. 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am Manager of Financial Analysis in the Corporate Financial Planning & Analysis group within the Treasurer's Department.

Q. Briefly describe your educational and professional background.

A. I earned a Bachelor of Science Degree in Business Administration and a Masters in Business Administration with an emphasis in corporate finance from the University of Southern California Marshall School of Business, and was a recipient of the Marshall Certificate in Financial Analysis and Valuation. I hold the Chartered Financial Analyst (CFA) designation and am a member of both CFALA and the CFA Institute. Prior to joining Edison, my professional background included working in the Corporate Restructuring practice at Arthur Andersen. Since joining Edison in 2002, I have developed revenue requirement models and performed a number of cost effectiveness analyses.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of this Exhibit SCE-3 as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A. Yes, it does.
Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF CHARLIE C. HU

Q. Please state your name and business address for the record.

A. My name is Charlie Hu, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am currently leading the Business Design effort for Edison SmartConnect™ Program at Southern California Edison. In this role, I am accountable for all back office activities needed to support Edison SmartConnect™. The back office activities include designing and implementing the business processes and information technologies needed to support Edison SmartConnect™. My direct and matrixed staffs include SCE project managers, subject matter experts, external consultants, and vendors.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Science (B.S.) degree in Computer Science from California State University of Los Angeles. I also completed the Management Program from Columbia University Graduate School of Business and various graduate classes from Pepperdine University. I have been in Southern California Edison for over seventeen years. I was in the Information Technology organization the first seven years where I held positions with increasing responsibility involving system development and implementation of our current billing system. The last ten years include leadership roles involving implementation of various major process improvement initiatives in the Customer Service organization with focus in the areas of customer service, metering, meter reading, field services, billing, and revenue collections.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of Exhibit SCE-3, as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF LAWRENCE M. OLIVA

Q. Please state your name and business address for the record.

A. My name is Lawrence M. Oliva, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am a Director in SCE's Customer Services Business Unit and I lead a group entitled Tariff, Programs and Services. This group is responsible for SCE's Demand Response programs.

Q. Briefly describe your educational and professional background.

A. I earned a Bachelor of Science Degree in Civil Engineering from Southern Methodist University in 1972. Prior to joining SCE as an employee this year, I was a business consultant in the energy industry for over 30 years. I was a principal and director of an international economics consulting firm, Putnam, Hayes and Bartlett, Inc., and a business consulting partner of Arthur Andersen. In past four years, I provided consulting services to SCE in the areas of demand response and advanced metering.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of this Exhibit SCE-3, as identified in the Table of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.

Application No.: 07-07-

Exhibit No.: SCE-4

Witnesses: A. Faruqui
R. Garwacki
L. Oliva

SOUTHERN CALIFORNIA
EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

EDISON SMARTCONNECT™ DEPLOYMENT FUNDING AND COST RECOVERY

Volume 4: Demand Response

Before the

Public Utilities Commission of the State of California

Rosemead, California

July 31, 2007

LAW #1366536

EDISON SMARTCONNECT™ DEPLOYMENT FUNDING AND COST RECOVERY

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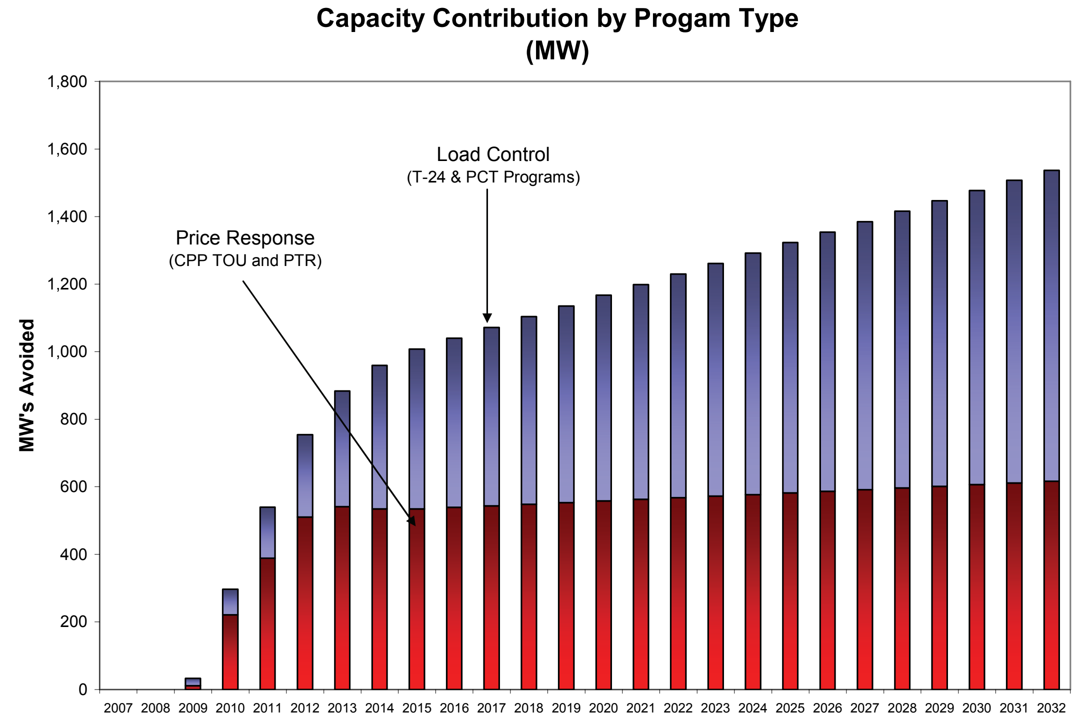
I.

INTRODUCTION

The purpose of this testimony is to provide an overview of the dynamic rates and demand response programs that SCE expects will be available with Edison SmartConnect™, and to discuss SCE's demand response objectives, guiding principles, key sensitivities and other relevant information. Edison SmartConnect™ presents a unique opportunity to provide SCE's customers with new energy management alternatives that will enable them to reduce energy costs by using electricity more effectively and efficiently. By providing access to near real-time energy use and costs and enabling dynamic pricing options for residential and small / medium business customers with price signals closer to actual costs than tiered or flat rate structures, Edison SmartConnect™ will be instrumental in managing peak consumption by providing an incentive for customers to shift some of their usage to off-peak hours. Edison SmartConnect™ enables a range of dynamic rate design options that can improve customer acceptance and satisfaction. Figure I-1 shows the expected reductions in peak demand as a result of the Edison SmartConnect™ enabled load control and price response.

Figure I-1
Estimated Peak Demand Reduction for Price Response and Load Control Programs



Chapter I of this volume is introductory in nature. Chapter II provides the background information that has shaped and influenced SCE's demand response and dynamic rate design, discusses the objectives and guiding principles utilized to design SCE's program, and sets forth a summary of SCE's demand response programs and dynamic rate designs.

Chapter III describes the load control programs, including Peak-Time-Rebate, Programmable Communicating Thermostats (PCTs), and Title 24 Program, and the dynamic rates, including Critical Peak Pricing (CPP) and Time-Of-Use (TOU), all of which SCE expects will be available with Edison SmartConnect™. This chapter also includes program details including participation rates, price elasticities, bill impacts, assumptions, compatibility with other demand response programs, and other items.

As discussed in Exhibit SCE-2, SCE seeks authorization to implement the Edison SmartConnect™ PCT Program as Edison SmartConnect™ meters are installed. SCE also plans to offer existing TOU and CPP rates for Edison SmartConnect™ customers pending authorization of revised TOU and CPP rates, which SCE plans to seek in Phase II of its 2009 GRC. These rates are discussed in detail in Chapter III and in the appendices of this volume.

Demand response tariff and program proposals and assumptions from previous SCE AMI business case filings are superseded by the program details described in this volume.

II.

DEMAND RESPONSE POLICIES AND OBJECTIVES

A. Guiding Principles

SCE's ultimate objective is to design a comprehensive program that meets the Commission's objectives for demand response as defined in Energy Action Plan II[1] and further addressed in Working Group 3.[2] SCE has reviewed the Commission approved AMI programs of Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) in researching the program characteristics that would best suit SCE's customers and meet regulatory policy goals. In so doing, SCE has developed the following principles for guidance and direction in developing a balanced, comprehensive program.

1. Encourage Demand Response Through Dynamic Pricing

Tariffs should encourage demand response through an appropriate differential between on-peak and off-peak prices. The Statewide Pricing Pilot demonstrated that a higher differential encourages customers to reduce usage during peak periods. Dynamic pricing includes rates differentiated by time of day and price increases or rebates on critical peak days when power resources are limited.

2. Promote Rate Equity

Dynamic rates should reflect equitable cost allocation amongst different customer segments. To the extent possible, rate group cross-subsidies should be minimized while adhering to public policy objectives.

3. Maximize Customer Participation

To achieve significant demand response, as many customers as possible should be exposed to dynamic pricing and should be encouraged to participate in these programs. However,

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[1] Energy Action Plan II, Implementation Roadmap for Energy Policies, dated September 21, 2005, by the California Energy Commission, the California Public Utilities Commission (the Commission).

[2] Rulemaking 02-06-001 of the Commission created Working Group 3, which was assigned to address issues surrounding possible expansion of the advanced metering infrastructure to include all customers.

dynamic pricing tariffs should be designed to minimize adverse customer impacts and to simplify the rate structure wherever possible.

4. Complement Load Control

Dynamic rates should complement load control programs rather than compete with them. In other words, usage reductions in response to dynamic pricing should work in conjunction with future and existing load control programs to decrease overall usage during peak periods.

5. Enable Customer Choice

Rate designs should offer adequate customer choice. Thus, dynamic rates should be adaptable, flexible and encourage demand response from customers.

6. Consistent with Law and Public Policy

Rate designs must be compliant with the law and consistent with the energy policies of the state, including AB1-X, the Energy Action Plan II, and other regulatory directives.

7. Dynamic Rates Should Be Revenue Neutral

Dynamic rates should be designed to be revenue neutral. However, optional rates, when combined with a knowledgeable customer population, could lead to revenue deficiencies. Deficiencies should be recovered from and surpluses should be returned to customers through an appropriate balancing account.

These guiding principles assist SCE in focusing on attaining a balanced solution to demand response. They recognize that the highest attainable level of demand response may not be optimal if it runs counter to public policy, inhibits customer choice, results in revenue deficiencies, or otherwise adversely impacts SCE's customers.

B. SCE Objectives for Demand Response Programs and Dynamic Rates

SCE has incorporated the Commission's guidance on demand response parameters and assumptions from PG&E's and SDG&E's AMI proceedings into its demand response program plans for Edison SmartConnect™. Specifically, the Commission approved PG&E's reliance on voluntary enrollment in TOU and CPP rates, and SDG&E's reliance on a peak-time rebate for residential customers and CPP rates for commercial and industrial (C&I) customers in their respective AMI cases.

SCE has incorporated these parameters and assumptions here to design what SCE believes is a balanced and comprehensive program that meets the Commission's objectives and SCE's guiding principles for demand response.

1. Demand Response Programs

a) Peak Time Rebate – Residential Customers

SCE's business case analysis for demand response includes a Peak Time Rebate (PTR) program for residential customers, which is described in detail in Chapter III. PTR provides credits for usage reductions during peak periods (*i.e.,* 2 p.m. to 6 p.m.) on designated critical days. PTR would be an "overlay" to customers' otherwise applicable tariff, whether TOU, or tiered rates, while providing a price signal to encourage load reduction during critical peak periods. SCE's PTR is similar to the program reviewed in SDG&E's AMI proceeding.[3]

The PTR complies with AB1-X, which limits potential demand response from residential customers whose usage does not exceed 130% of their baseline allocation because the law restricts changes to the corresponding Tier 1 and Tier 2 rate levels. Approximately 45% of SCE's residential customers are not exposed to rates above Tier 2.[4] Residential customer usage up to 130% of baseline is protected by the AB1-X rate cap. Under the Commission's interpretation of AB1-X, residential customers cannot be placed on another rate schedule or an overlay such as a dynamic rate schedule that may result in higher bills as their default rate schedule. Thus, AB1-X limits the demand response options for residential customers.

The advantages of PTR include (i) the eligibility of all residential customers for a rebate incentive to reduce usage on critical days; (ii) the coupling of rebates with load control programs to enable pay-for-performance; (iii) the positive reinforcement of a "carrot-only" approach that encourages early acceptance and adoption by millions of ratepayers; and (4) the flexibility such that program features like rebate amounts can be altered without changing customer tariffs.

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[3] D.07-04-043, Opinion Approving Settlement on SDG&E's AMI Project, April 12, 2007.

[4] SCE's analysis of 2005 residential usage showed that approximately 45% of customers never received a bill containing any tier 3 charges.

As detailed in Chapter III and the appendices, the PTR program for the residential class is estimated to provide a peak demand reduction of 410 MW by 2013. This excludes peak demand reductions from load control programs that also rely on PTR as an incentive, which are estimated separately.

b) Load Control Programs – Residential Customers

SCE has one of the largest air conditioning load control programs in the world. Over 220,000 residential customers participate in SCE's current Summer Discount Plan that uses one-way radio frequency switching of on/off devices attached to outdoor compressor units. SCE pays customers incentives in the summer season for customer enrollment in the programs. The program is relatively simple, but offers customers limited flexibility and does not convey directly the customer comfort effect of load control. Providing customers better information about comfort via a thermostat set point and allowing customers some flexibility to override a limited number of events would serve to increase customer enrollments even at lower incentive payments.

Edison SmartConnect™ infrastructure enables communication with PCTs that are designed for load control under the proposed Title 24 building code standard. PCTs are expected to be commercially available in late 2007 and SCE plans to conduct final testing in 2008 consistent with final T24 specifications. With Edison SmartConnect™, SCE can offer two-way communication with PCTs to transfer temperature set point information, event status, and enable customer override. Edison SmartConnect™ meters, through the HAN interface, will be the link between the PCTs and the SCE communication infrastructure.

SCE proposes to enroll customers in an Edison SmartConnect™ Thermostat program in two ways. First, SCE will take advantage of the implementation of the Title 24 building code standard beginning in 2009. According to the proposed standard, all new homes with central air conditioning and heating, ventilation and air conditioning (HVAC) retrofits requiring building permits must have Title 24 compliant PCTs installed. Residential customers equipped with PCTs due to the implementation of this standard will be eligible for the Edison SmartConnect™ Summer Discount Plan. Second, SCE plans to offer rebates to customers to purchase and install T24 compliant PCTs without being subject to building code requirements (*i.e.,* not a new home or retrofit) and enroll in SCE's SmartConnect™ Summer Discount Plan.

The Edison SmartConnect™ Summer Discount Plan would pay an incentive and allow event overrides that would reduce the incentive each time it was exercised, for a limited number of times. Residential customers on this program would also be eligible for PTR rebates. In this way, load control becomes a pay-for-performance approach to demand response.

SCE will continue to operate the existing Summer Discount Plan with one-way A/C compressor switches but the program will be closed to new enrollments beginning in 2009. SCE will have approximately 600 MW of dispatchable peak load on the existing program by the end of 2007. SCE does not include power procurement benefits from this existing program in the Edison SmartConnect™ business case.

In addition to dispatch for reliability, SCE plans to dispatch the Edison SmartConnect™ Summer Discount Plan and the existing Summer Discount Plan for economic reasons.[5] Economic dispatch of load control would be based on a price signal. The dispatch for economic reasons could be up to 15 times per year.

SCE expects that it can reasonably enroll about 25% of residential customers with central air conditioning through a combination of its existing Summer Discount Plan program or a new Edison SmartConnect™ Summer Discount Plan involving Title 24 compliant PCTs. SCE does not seek authority to dispatch the existing Summer Discount Program in this Application. SCE plans to seek such authority as part of its 2009-2011 demand response program application.

c) Summary of Eligibility and Benefits

The following table outlines eligibility in SCE's demand response programs for residential customers.

[5] SCE does not seek authority to dispatch the existing Summer Discount Program in this Application. SCE plans to seek such authority as part of its 2009-2011 demand response program application.

Table II-1
Summary of Residential Customer Eligibility for Edison SmartConnect™ Demand Response Programs

PTR	• Residential customers (except those on CPP)[6]
Edison SmartConnect™ PCT Program	• Residential customers with T24

The following figures summarize the forecast demand response MW reduction by 2013, the first year that Edison SmartConnect™ will be fully deployed.

Table II-2
Edison SmartConnect™ Enabled Demand Response Program Estimated Reductions by 2013 (in MW)

PTR – Residential	410
Edison SmartConnect™ PCT Program	342

Given certain capacity costs and other assumptions outlined in Appendix B, the estimated megawatt (MW) savings for the Edison SmartConnect™ demand response programs provides significant benefits as summarized in Exhibit SCE-3. The appendices hereto provide further information on these demand response programs, including assumptions regarding price elasticity, participation rates, and capacity costs.

2. Dynamic Rates

a) Voluntary Dynamic Rates for Residential Customers

SCE believes that the ultimate solution to sustainable demand response is dynamic time differentiated rates. Due to the AB1-X limitations on dynamic pricing for residential

[6] Residential customers on the CPP rate will not be eligible for the PTR program.

customers, SCE will offer CPP and TOU rates to residential customers on a voluntary basis, although the bulk of demand response from this class is expected to come from PTR and load control. In the Statewide Pricing Pilot of dynamic rates in 2003 and 2004, SCE found that it was difficult to recruit customers onto dynamic rates for the program, despite bill protections and incentive payments. Thus, SCE does not anticipate significant enrollment on a purely opt-in basis without substantial marketing and promotion.

b) Voluntary Critical Peak Pricing (CPP) for Residential and C&I Customers under 200 kW

SCE plans to offer business customers under 200 kW a CPP rate on a voluntary (opt-in) basis. CPP will be beneficial for those customers that can reduce their load during system peak days. A CPP rate provides for significant price increase for all usage during peak periods (*i.e.,* 2 p.m. to 6 p.m.) of critical days, offset by reduced prices during non-CPP periods.

SCE will also offer CPP rates to residential customers on a voluntary opt-in basis. However, a residential customer on CPP is not eligible to participate in the PTR program. Based on the similarities in the expected change in customer usage between the two programs, the CPP benefits are embedded in the PTR benefit estimates, which assumes 100% enrollment.

c) Time-Of-Use (TOU) for Residential and C&I Customers under 200 kW

SCE expects to default medium C&I customers (20 to 200 kW) to a TOU rate. The TOU rate will reward demand response on a year-round basis relative to the customers' Otherwise Applicable Tariff (OAT). To preserve customer choice, SCE retains the OAT as an opt-out option. To the extent that a revenue deficiency results from customers opting to their lowest available rate, the deficiency would be recovered from the rate group via a hedging premium added back into the OAT.

Small C&I customers (below 20 kW) will have the option of enrolling in a TOU rate. As stated previously, the Statewide Pricing Pilot did not demonstrate that this customer group is responsive to time-based priced signals. Thus, while small C&I customers (< 20 kW) may provide demand response under a TOU rate, SCE assumes no demand response benefits from the small C&I customers for purposes of the Edison SmartConnect™ business case.

SCE will also offer TOU rates to residential customers on a voluntary (opt-in) basis.

The following table outlines SCE's customer eligibility for Edison SmartConnect™ dynamic rates.

Table II-3
Summary of Eligibility for Edison SmartConnect™ Dynamic Rates

Voluntary CPP	• C&I customers (0 kW to 200kW) • Residential customers
Voluntary TOU	• Small C&I customers (< 20kW) with Edison SmartConnect™ meter • Residential customers with Edison SmartConnect™ meter
Default TOU	• Medium C&I customers (20 kW to 200 kW)

Given certain capacity costs and other assumptions outlined in Appendix B, the estimated demand response MW reduction from Edison SmartConnect™ dynamic rates by 2013 is shown below.

Table II-4
Edison SmartConnect™ Enabled Dynamic Rates
Estimated Reductions by 2013 (in MW)[7]

CPP	78
TOU –	53

The appendices hereto include further information on Edison SmartConnect™ dynamic rates, including assumptions regarding price elasticity, participation rates, and capacity costs.

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[7] This table includes MW reductions counted for business case purposes. SCE anticipates that there will be participation and MW reductions for all rate offerings, however, it indicates zero MW reductions where SPP data for megawatt reductions were inconclusive or where it is already counting MW reductions, *i.e.,* for residential customers on CPP rates, those reductions are incorporated in the estimates for PTR MW reductions.

III.

DESCRIPTION OF DEMAND RESPONSE PROGRAMS AND DYNAMIC RATES

The purpose of this Chapter is to describe SCE's plan for dynamic rates and load control programs with Edison SmartConnect™. In this Chapter, SCE provides details of Edison SmartConnect™ demand response programs and dynamic rates, including pricing and reliability, events, customer eligibility, incentives, and bill impacts. Further information, including methodologies and specific program elements are included in the appendices to this Volume.

A. Demand Response Programs

1. Peak Time Rebate (PTR)

SCE's proposed PTR program would apply to all residential customers and is similar in concept to the SDG&E PTR program approved in D.07-04-043. The PTR rebate will be an "overlay" to the customer's OAT, whether TOU or tiered rates, and will provide for credits for usage reductions during peak periods of PTR event days.

a) Program Summary

The proposed PTR program will have the following attributes, which are described in more detail in Appendix A:

- Events. Designed for 15 PTR events per year.
- Peak Period. During an event, PTR rebates will be applied to weekday usage from 2 p.m. to 6 p.m., except holidays.
- Event Notification. Customers would be notified of a PTR event through mass media and other communication channels beginning the day prior to the event's occurrence.
- Rebate. Customers would be paid $0.66 / kWh for each kWh reduction during a PTR event. Total potential customer savings could be more than

$0.66 / kWh, as any net usage reduction would also result in bill savings from their OAT.[8]

- Eligibility. All residential customers with Edison SmartConnect™ will be eligible to earn PTR rebates except those on a CPP rate. No proactive steps would be required by customers to sign up for this program. Customer awareness is discussed in the Appendix B to this volume.
- Customer Specific Reference Level (CSRL). SCE is currently assessing various CSRL calculations to maximize customer understandability and reduce free-ridership. However, for purposes of the Edison SmartConnect™ business case, SCE assumes a CSRL based on an average of the customer's highest usage on three of the previous five eligible non-event days prior to the PTR event.
- AB1-X Compatible. PTR is an overlay to a customer's OAT and is compatible with AB1-X. All residential customers, regardless of usage, will have the opportunity to reduce their bills based on their OAT through this program.

After careful consideration of the impacts to customers, rates, and public policy, SCE plans to offer PTR for residential customers. The following are highlights of the PTR program development considerations.

- PTR provides significant potential customer savings during critical events, thereby encouraging demand response.
- PTR maximizes customer participation, as all residential customers (except those on CPP) will be automatically enrolled in the program.

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8 This PTR credit of $.66/kWh is used as a reasonable level of credit for the purpose of forecasting the demand response in this application. SCE will re-evaluate this credit in Phase II of its 2009 GRC.

- Customers can only win on this program, as there are no penalties for not reducing usage during an event.
- PTR is compliant with AB1-X and consistent with California's Energy Action Plan.

b) Comparisons to Critical Peak Pricing

As described below, given the current constraints imposed by AB1-X and the limited customer adoption of CPP, PTR provides the best opportunity to encourage residential customers to provide significant demand response.

Effects of AB1-X. As discussed in Rulemaking 02-06-001,[9] the rate restrictions imposed by AB1-X limit the ability to derive substantial demand response benefits from residential customers. Residential customers using less than 130 percent of their baseline allowance cannot be charged TOU or CPP rates unless they voluntarily opt in to a TOU or CPP rate. For SCE, approximately 45% of its residential customers use less than 130% of their baseline allowances.[10] Under the Commission's interpretation of AB1-X, default dynamic pricing schedules are not allowed, drastically reducing the potential demand response from residential customers under either Critical Peak Price or TOU tariffs.

PTR Maximizes Residential Customer Demand Response. Given the timing of the Edison SmartConnect™ program, SCE has evaluated various changes to its dynamic rate design to elicit increased customer participation. Among those alternatives, a peak-time rebate provided a means for residential customers using less than 130% of baseline to contribute to demand response without risk of a bill increase. Thus, PTR supports the program's guiding principle of maximizing customer participation.

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[9] *See* R.02-06-001, Assigned Commission and Administrative Law Judge's Ruling Calling for a Technical Conference to Begin Development of a Reference Design Delaying Filing Date, November 24, 2004.

[10] *See* fn. 3 *supra*.

SCE believes that when the rate limits of AB1-X are lifted or expire, the dynamic rate structure for residential customers should be reevaluated. However, until that time, PTR provides the best means to maximize residential customers' demand response.

SPP Market Momentum Enrollment Estimate. The Statewide Pricing Pilot's (SPP) Momentum Market Intelligence (MMI) model found that on an opt-in basis, only about 20% of customers would opt onto CPP rate. Furthermore, MMI's market research found that the CPP-F pilot rate would yield an opt-in market share of 10% of customers that had thirty percent awareness of their rate options, 17% enrollment with fifty percent awareness, and 34% enrollment with one-hundred percent awareness.

Because this market research indicates that the vast majority of customers do not want to voluntarily opt-in to CPP rates, a PTR program for residential customers is preferred until AB1-X constraints end.

c) Summary of Impacts

Applying the results of the SPP, PTR is estimated to provide approximately 410 MW of demand response by 2013 when Edison SmartConnect™ is fully deployed. See Appendix B for a discussion on assumptions and methodologies.

2. Load Control Programs

a) Edison SmartConnect™ Thermostat Programs

The CEC's Title 24 building code initiative for PCTs has provided SCE an opportunity for Edison SmartConnect™ to enable reliable demand response benefits with a PCT program.

The Edison SmartConnect™ system will enable two-way communications with PCT devices that enable the dispatch of command signals, provide information about event status and allow event override. Such features enhance the appeal of load control and increase customer enrollment in programs. The PCT will be activated and controlled via the Edison SmartConnect™ meter and communications system. The PCTs of customers on the program will provide air conditioner compressor curtailment during peak periods by increasing the thermostat set point. Edison

SmartConnect™ will also provide customers with valuable usage information on SCE's website to analyze energy usage patterns to help evaluate how their appliances affect their electricity costs and make appropriate adjustments. Edison SmartConnect™ also allows future functionality for customers to control their PCT and other compatible appliances through the internet or other remote devices.

The SPP report for 2004 and 2005[11] indicates that significant load reductions will be achieved with enabling technology in the commercial and industrial classes as well. SCE will consider future load control programs for the commercial and industrial classes.

b) SCE Existing Summer Discount Plan

SCE plans to retain its existing Summer Discount Plan, but close it to new enrollments when the Edison SmartConnect™ is implemented. By 2009, SCE expects to have over 300,000 residential customers enrolled in its Summer Discount Plan. Edison SmartConnect™ can enable a new approach to load control with these devices to yield reliable peak shaving. This can provide additional sub-transmission and distribution related capital deferral benefits over the existing air conditioning cycling program.

c) Summary of Eligibility and Benefits

Residential customers become eligible for the Smart Thermostat program when a SmartConnect™ meter is installed and a PCT is present in their residential home. There are two ways customers will obtain PCTs. First, SCE customers may purchase a Title 24 compliant PCT and receive a rebate for the purchase and installation costs up to a total of $125 in their existing homes. Second, the Title 24 building code will require the installation of a PCT during new residential construction or permitted HVAC retrofits that require permits.

The CEC is pursuing Title 24 –Building Code changes requiring PCTs for residential new construction and residential HVAC retrofits. The new code will require that all new homes and HVAC retrofits with central air conditioning have a Title 24 compliant thermostat installed. Beginning in 2009, when the new California Building Code is effective, SCE assumes that 25% of

[11] California's Statewide Pricing Pilot: Commercial & Industrial Analysis Update, Final Report, dated June 28, 2006, prepared by Freeman, Sullivan & Company, and Charles River Associates.

customers with PCTs (residential new construction and a portion of residential retrofit construction) with Edison SmartConnect™ meters will enroll in an Edison SmartConnect™ Thermostat program described above. Title 24 project customers (new construction and retrofit) would not be eligible for a thermostat or installation rebate.

SCE believes that it can reasonably enroll about 25% of residential customers with central air conditioning in a load control program – either on its existing Summer Discount Plan, or a new Edison SmartConnect™ Thermostat program involving Title 24 compliant PCTs. To reach this market penetration of customers not already on the two programs mentioned above, SCE assumes another 250,000 existing customers could be enrolled on an Edison SmartConnect™ Thermostat program. All enrolled residential customers would be eligible to receive an annual incentive and be eligible for PTR rebates, as applicable. Customers would also be allowed to override load control events up to five times per season at a charge at a predetermined charge per override.

B. Dynamic Rates

SCE's approach to dynamic rates is to provide a "natural progression" commensurate with expected customer sophistication based on customer size. A default PTR overlay is the preferred means to provide dynamic price signals to SCE's residential customers with customers having the option of selecting TOU rates.

In keeping with SCE's desire to provide customer choice, more sophisticated options are available for each customer class.[12] GS-2 customers who have historically been exposed to the billing nuances associated with demand charges (those exceeding 20 kW of billing demand) will now be asked to extend this level of sophistication to include default TOU rates.

The figure below summarizes the rate offerings, as they would appear as the Edison SmartConnect™ meter deployments occur. While not the subject of this application, displaying the default CPP requirement for customers greater than 200 kW who are already required to be served on a TOU rate displays the complete spectrum of rate sophistication progression in a tabular format.[13]

[12] GS-1 customers will have opt-in TOU and CPP rates available to them.

[13] Default CPP for customers greater than 200 kW was ordered in D.06-05-038.

Table III-5
Dynamic Rates by Customer Class

	CPP	TOU
Residential	Opt-in CPP	Opt-in TOU
Small C&I (< 20 kW)	Opt-in CPP	Opt-in TOU
Medium C&I (20 kW to 200 kW)	Opt-in CPP	Default TOU
Large C&I (> 200 kW)	Default CPP[14]	Mandatory TOU

1. Critical Peak Pricing (CPP)

Critical Peak Pricing (CPP) is an event-based pricing program which will be designed for SCE's C&I (< 200 kW) and residential customers. The CPP program will provide for significant charges for usage during peak periods (*e.g.*, 2 p.m. to 6 p.m.) of CPP event days. In addition, the CPP charge will be an "overlay" to TOU or OAT.

a) Program Summary

The CPP program will have the following attributes:

- Events. SCE may call up to 15 CPP events per year.
- Peak Period. During an event, CPP charges will be applied to weekday usage from 2 p.m. to 6 p.m., except holidays.
- Event Notification. Customers would be notified of a CPP event through mass media and other communication channels beginning the day before such an event.

[14] In D.06-05-038, the Commission ordered each utility to "incorporate default critical peak pricing tariffs for all eligible customers 200 kilowatts (kW) and above into their next comprehensive rate design proceeding or other appropriate proceeding if directed by the Commission."

- CPP Charges. Customers will be charged $0.66 / kWh in addition to their TOU or OAT rate. SCE's CPP charges are presented here for illustrative purposes. SCE requests that the final dynamic rate designs be established in Phase II of SCE's 2009 GRC, which is expected to be filed in early 2008.[15]
- Participation. All bundled service small and medium C&I, and residential customers will be able to participate. Agriculture and streetlight customers are excluded from the program. The CPP participation rate for medium C&I customers, as determined by the Momentum Market Intelligence simulator tool was determined to be 25.3%. Residential customers on the CPP rate will not be eligible for the PTR program.

b) Program Selection and Comparisons to Default Critical Peak Pricing

The following list highlights the CPP program development considerations.

- CPP rates and other load control programs enable customer choice by being available to small and medium C&I customers on an opt-in basis;
- CPP preserves the current cost allocation among customer rate groups, as the rate will be charged as an overlay to the customer's TOU or OAT rate.
- CPP complies with the law, and is consistent with California's Energy Action Plan.

For C&I customers with demands greater than 20 kW and less than 200 kW, ("medium C&I") CPP provides a strong, direct price signal and can be used in conjunction with TOU. SCE analyzed CPP on both an opt-in and default basis. Given the following considerations, SCE proposes to provide CPP on an opt-in basis to its medium C&I customers.

- Preserves customer choice. Opt-in CPP preserves customer choice by allowing customers the option of participating in the CPP program.

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[15] In D.05-11-009 the Commission determined that dynamic pricing tariff options for all types of customers should be addressed in each utility's comprehensive rate design proceeding. *See* D.05-11-009, Ordering Paragraphs Nos. 3, 4, and 5.

- Minimize adverse customer reactions. In consideration of customer concerns, the company would prefer to limit the use of "mandatory" programs. Rate changes, particularly those that involve a default tariff in addition to the OAT rate, could result in negative customer reactions. In addition, potential customer backlash will be avoided. As evidenced by the repeal of Puget Sound Energy's TOU rate program, a demand response tariff may result in a customer backlash if the majority of customers do not see value in the rate offerings. Opt-in CPP better preserves informed customer choice, relative to default CPP. Thus, CPP provided on an opt-in basis will minimize adverse customer reactions relative to a default CPP tariff.

Additionally, given the inherent uncertainties associated with a new program, it is difficult to anticipate customer responses. Thus, SCE understands that it is important to adopt a flexible program that can be modified, as necessary, to adhere to the purpose and intent of the program.

c) Summary of Impacts and Benefits

Opt-in CPP for SCE's medium C&I customers is estimated to have a demand response impact of 78 MW by 2013 and resulting nominal benefits of $187 million. Consistent with the SPP results, SCE did not calculate any demand response benefits from C&I customers with demands less than 20 kW ("small C&I") into the business case. SCE believes this is an overly conservative assumption. *See* Appendix B for detailed assumptions and methodologies.

2. Time-Of-Use (TOU)

a) Residential

In addition to PTR, SCE will provide an opt-in TOU program for its residential customers. The TOU program is a non-event based rate which will provide customers an incentive to reduce usage during peak periods throughout the year. Eligible customers may opt in to TOU from their current five tier rate schedule (OAT). TOU rates analyzed as part of this business case comply with

AB1-X requirements.[16] [17] For the purpose of this business case analysis, rates for low usage customers (Tiers 1 and 2) remain unchanged, with usage greater than Tier 2 being subject to TOU rates. For the purposes of this business case, SCE has assumed that low usage customers (Tiers 1 and 2) will remain on OAT, while higher usage customers (Tiers 3, 4, and 5) may opt into TOU.

Program Summary. The TOU program will have the following attributes:

- Peak Period. Peak periods will be from 2 p.m. to 6 p.m. weekdays, except holidays.
- Summer Season. While the current TOU-D summer season is defined as 12:00 a.m. on the first Sunday in June and continue until 12:00 a.m. of the first Sunday in October of each year. SCE plans to request a summer season from June 1 to October 1 for each year.
- Rate Structure. Because of the AB1-X cap restrictions, the TOU rate was designed to be revenue neutral to Tiers 3, 4 and 5 with no bill impacts to Tier 1 and Tier 2 customers.
- AB1-X compliance. In D.06-10-051, the Commission ruled that opt-in TOU or CPP rates do not necessarily need to comply with AB1-X provisions. SCE will explore alternative TOU-D rate designs and file its final proposals in the 2009 GRC proceedings.
- Participation. Based on an analysis of bill impacts, SCE estimated that 5.5% of customers would opt-in to the TOU rate. Tier 1 and 2 customers,

[16] One of the modifications being explored is an iterative rate design which is initially established as revenue neutral to the average Tier 3-5 customer. From an assumed participation rate of customers who would realize a reduced bill from TOU participation, the estimated revenue deficiency would either be rolled back into the TOU rate as a participation credit or into the tiered rate as a hedging premium. This is consistent with some of the more recent rate design direction currently being discussed at the CEC. *See* CEC draft report, California's Next Generation of Load Management Standards, Ahmad Faruqui and Ryan Hledlik, May 2007, CEC-200-2007-007-D.

[17] Note that in Decision D.06-10-051, the Commission effectively ruled that AB1-X rate protection does not exist for those customers who choose to opt-in to non-AB1-X conforming rates. While the residential TOU rates presented here do comply with strict AB1-X provisions, SCE is currently studying alternative residential TOU structures and will make its final proposals in its 2009 GRC rate design proceeding (GRC-Phase II).

representing 45% of SCE's customers,[18] will not receive any benefit from the TOU rate. Thus, similar to PTR, AB1-X constraints limit the potential demand response from the TOU rate.

(1) TOU Complements PTR.

While PTR provides a price signal to customers during certain peak days, TOU provides a price signal for customers throughout the year. Year round price signals are important steps in providing equitable cost recovery from those customers whose natural usage pattern is less costly to serve (*e.g.,* primarily night and week-end energy consumers). TOU also provides a compensation mechanism for customers who are willing and able to engage in a permanent load shift (*e.g.,* resetting of a pool pump to off-peak).

For purposes of this business case analysis, SCE has designed its TOU peak period to be consistent with the proposed PTR peak periods. That is, both programs will have a peak period from 2 p.m. to 6 p.m.[19] Customers enrolled in TOU will only need to remember that peak periods are always from 2 p.m. to 6 p.m., regardless of the specific program.

Narrowing the peak period (2 p.m. to 6 p.m.) to four hours compared to the existing six-hour period creates a larger price differential, which allows for increased demand response. A longer peak period would decrease the on-peak TOU rate and dilute the demand response effects.

Although TOU is intended to provide incentives to change customer behavior, because of the AB1-X legislative constraints, TOU will not provide a price signal to lower usage customers (Tiers 1 and 2). More specifically, those customers with usage of less than 130% of their baseline will not be provided an economic incentive to enroll in TOU rates.

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[18] From an initial estimate of 10%, since approximately 45% of customers never received a bill with tier 3 usage, the final participation rate was reduced to 5.5% (55% times 10%).

[19] Narrowing the peak period represents an initial assumption regarding customer preferences of a consistent, narrow TOU period. SCE expects to have these customer preferences validated by the time of its 2009 GRC Phase II application. The definition of TOU-D structures is expected to be debated vigorously during the Phase II proceedings.

(2) Summary of Impacts and Benefits.

Residential customers enrolled in opt-in TOU are estimated to provide approximately 4 MW of demand response by 2013 and the nominal value of demand response benefits that total $14 million.[20] *See* Appendix B for detailed assumptions and methodologies.

b) Commercial and Industrial

In addition to CPP, SCE will continue to provide Time-Of-Use (TOU) rates for its small and medium C&I customers. The TOU program will provide customers an incentive to reduce usage during peak periods throughout the year. Medium C&I customers (20 kW to 200 kW) will be defaulted to the TOU rate, and will have the choice to opt out into the GS-2 rate, while small C&I customers (< 20 kW) will remain on GS-1 with the option to opt-in to a TOU rate.

Consistent with the SPP results, SCE has not calculated any demand response reductions from its small C&I customers (< 20 kW).

(1) Program Summary.

The medium C&I TOU program will have the following attributes:

- Peak Period. Consistent with current summer TOU peak periods for the standard TOU-8 rate group, peak periods will be from 12 p.m. to 6 p.m. summer weekdays, except holidays.
- Summer Season. The summer season will be consistent with the current TOU rates offered to these rate classes.
- Participation Rate. Participation rates for medium C&I customers is estimated to be 46.5%. This high participation rate is due to the default nature of the program.

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20 To avoid double counting the demand response benefits, customers enrolled in both PTR and TOU have been excluded from these amounts.

(2) TOU Complements CPP

TOU complements CPP by providing a price signal for customers throughout the year. Year round price signals are important steps in bringing about a permanent customer behavioral shift. Furthermore, for medium C&I customers, SCE analyzed CPP on both a default and mandatory basis. Given the following considerations, SCE will provide TOU on a default basis to all medium C&I customers.

- Increased customer knowledge regarding energy efficiency and demand response opportunities. Default TOU ensures that all medium usage customers are exposed to dynamic pricing. Even customers opting back to their OAT will be exposed to the goals of dynamic pricing and energy efficiency. Awareness could potentially set the stage for future dynamic pricing changes and a conservation effect for this rate group.
- Preserves customer choice. Default TOU preserves customer choice by allowing customers the option of reverting back to their OAT.
- Minimize adverse customer reactions. In consideration of customer concerns, the company would prefer to limit the use of "mandatory" programs. Rate changes inevitably lead to some customers reacting adversely to the new rate. In particular, mandatory rate changes, without the option of other rates, result in more inquiries and reactions from the affected customer group. A default TOU rate is estimated to provide significant demand response, yet provide the additional flexibility of enabling customer choice.

Given the benefits of demand response, increased customer awareness, and customer choice, SCE will provide a default TOU rate for all medium C&I customers.

(3) Summary of Impacts and Benefits.

Default TOU for SCE's medium C&I customers is estimated to provide approximately 49 MW of demand response by 2013 and the nominal value of demand response benefits that total $176 million. *See* Appendix A for estimated bill impacts and Appendix B for detailed assumptions and methodologies.

3. Continuing Assessment of Pricing Options

SCE will continue to investigate and assess dynamic pricing options, and SCE may revise its elements of its dynamic pricing structure in the 2009 GRC Phase II proceeding, which is expected to be filed in early 2008.[21]

C. Other Program Attributes

1. Conservation Effect

The SCE Demand Response programs provide customers in both retail and wholesale electricity markets with a choice whereby they can respond to dynamic or time-based prices or other types of incentives by reducing and/or shifting usage, particularly during peak periods. The conservation effect of these demand response programs is the reduction of energy used by specific end-use devices or energy systems, without affecting the services provided; reducing overall electricity consumption, often without explicit consideration for the timing of program-induced savings.

Experience to date indicates clearly that demand response reduces total electricity consumption. In a Meta-study of over 100 demand response programs it was found that electricity customers cut energy consumption.[22]

- Dynamic Pricing programs: average 4% total energy savings
- Customer Feedback programs: average 11% savings
- Reliability programs: ~0.2% (est.)

[21] *See* fn. 13, *supra*.

[22] King and Delurey, Efficiency and Demand Response: Twins, Siblings, or Cousins? Public Utilities Fortnightly, March 2005.

Several aspects of demand response reduce consumers' overall energy usage, the magnitude of which depends not only on the technologies and practices used, but whether they are developed and deployed with efficiency in mind. Education and support to the customer, important in energy-efficiency programs, also are important to demand response programs. One of the most common demand response applications (particularly in commercial buildings and particularly for short periods) is the dimming of lights or switching off of certain fixtures. Lighting- based demand response does not shift load, it eliminates the load without a rebound because post-event, the area will not be "overlit" to compensate for the earlier "under" lighting.

An analysis of two commercial-sector programs in California revealed that less than one-fourth of participants reported compensating for demand response with higher usage either before or after the demand response event (5 percent and 17 percent of all participants respectively). SCE believes that the most significant and positive relationship between demand response and energy conservation is that demand response increases energy awareness and provides feedback for consumers on their usage behavior. There is an extensive body of experience with utility programs that influence behavior by providing feedback and energy information directly to customers.

Given the wide body of studies used to validate the conservation effect, SCE assumed that for each customer class on a Demand Response program, their average annual MW usage would decrease by 1%. SCE assumed that the average MWh per year is the following:

Table III-6
Average Annual MWh by Customer Demand

Customers	Annual MWh
All Below 20kW	7 MWh
C&I >20kW <100kW	100 MWh

It is estimated that the conservation effect of customers on a demand response program will have an impact of 382,332 MWh in 2013 and resulting nominal benefits of $636 million using the estimated avoided energy costs per MWh.

The Edison SmartConnect™ program is designed to provide a range of energy information and enabling rates and programs to customers to encourage peak load reduction and energy conservation. For the purpose of this business case, SCE has quantified the energy conservation effect only based on the related conservation effect from demand response as described above. SCE recognizes the real potential for conservation resulting in better information for customers on their usage, which will be provided through the internet on a next-day basis, as well as available on more frequent intervals (as often as five seconds) directly from the meter. This is also discussed in the Societal Benefits section of Exhibit SCE-3.

2. Capital Deferral

SCE also performed an analysis of the benefits of sub-transmission and distribution related capital deferral for all demand response tariffs and programs.

Upgrade Avoidance. Distribution related capital deferral related to avoidance of upgrades to existing facilities enabled by Edison SmartConnect™ provides a significant cash flow benefit to SCE. SCE assumed that 20 percent of the projected distribution capital growth related to existing infrastructure could be deferred due to the Edison SmartConnect™ projected MW peak load reductions. The remaining 80 percent of sub-transmission and distribution required capital growth related to existing facilities is unavoidable because of necessary upgrades. The deferred capital spending is based on a 10-year average of estimated sub-transmission and distribution capital costs or $412 thousand per MW. The capital deferral is assumed to begin two years from the year the MW are saved.

The capital deferral related to upgrades to existing distribution related facilities results in a net demand response nominal benefit of $222 million. The transmission capital deferred is based on the incremental MW reduction from Demand Response Programs and Dynamic Rates described in this filing. The capital deferral benefits is inclusive of the dispatch of the existing air conditioning cycling program in a new approach that can provide additional sub-transmission and distribution related capital deferral benefits.

Appendix A

Definitions and Program Descriptions

A. Definitions

The following terms and definitions that are used throughout the Volume 4 testimony and appendices.

- Demand Response refers to customer alteration of electricity usage in response to price signals or incentive mechanisms.
- Dynamic Rates or Dynamic Pricing refers to electricity prices that reflect short term changes in the cost of energy. Rate structures such as Critical Peak Pricing and Time-Of-Use are examples of dynamic pricing options (see definitions below). TOU tariffs are also included under the heading of dynamic pricing here, because prices vary to reflect time of day costs. However, they do not generally vary based on current market conditions.[23]
- Time Differentiated Rates (TDR) refer to electricity prices that depend on the time of day the electricity is used. Time of Use and Critical Peak Pricing rates are TDRs that encourage customers to reduce consumption during on-peak periods by reflecting a combination of the wholesale cost of electricity and the system load in higher on-peak prices.
- Time of Use (TOU) is rate in which predetermined electricity prices vary as a function of usage period, typically by time of day, by day of week, and / or by season.[24]
- Critical Peak Pricing (CPP) is a dynamic rate that allows a short-term price increase to a predetermined level (or levels) to reflect short-term energy costs. In a fixed-period CPP, the time and duration of the price increase are predetermined, but the days are not predetermined. In a variable-period CPP, the time, duration and day of the price increase are not predetermined.
- Peak Time Rebate (PTR) is a demand response program that provides for a direct incentive rebate to encourage customers to reduce usage during peak periods of event days.

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[23] *See* Assigned Commissioner Chong's July 25, 2006 Ruling in A.06-03-005, at p.4.

[24] *See id.*

- Default Rate refers to a tariff selection made automatically without the active consideration by customers. When customers are automatically enrolled in a default rate, they may also be given a choice to "opt-out" to other optional tariffs.
- Mandatory Rate refers to a tariff which is provided to customers without other optional rates.

B. Peak Time Rebate (PTR) Design

As discussed in Chapter III, the Peak Time Rebate (PTR) program will be available for residential customers. Details of the PTR program are outlined below.

1. PTR Events

Number of Events. The proposed PTR program is designed for 15 events per year. These events may occur any time of year (*i.e.* PTR events are not limited to the summer season); although SCE expects the large majority of the events to be called during the summer season from June to September.

Peak Period. During a PTR event, the PTR peak period will be from 2 p.m. to 6 p.m. Furthermore, based upon the SCE specific customer SPP load data from CPP-F and control customers, SCE estimated that 50% of the load drop will be shifting to off-peak hours. Even though there is expected to be a shift in usage, an analysis of SCE's system peak load profile demonstrates that the shift will occur without creating a new system peak in the shoulder periods (*i.e.*, the "rebound" effect").

Notification. PTR events will be called on a "Day Ahead" basis. Notification will begin by 3 p.m. the day before an event would be called. Additionally, as described in Volume 2, SCE expects to notify customers of a PTR event through public broadcasts, voice messages, text messages and other appropriate communication channels.[25]

Trigger Mechanism. SCE will use a trigger mechanism to identify event days. PTR event days may be triggered by the occurrence of one or more of the following:

[25] In the longer term, notification of pricing events such as PTR could vary from day ahead to day of depending on system needs as media communications from advanced technologies, such as text messaging, iPhones, *etc.* become more prevalent. In this context, the current Commission definition of "day of" programs being defined as system reliability programs will need refinement.

- CAISO Electrical Emergency Alerts. From a statewide perspective, the CAISO may issue an Electrical Emergency Alert. Upon notification that such an alert has been declared, SCE may notify customers that the following day will be a PTR event day.
- SCE System Emergencies. Events may also be triggered when SCE experiences a system emergency related its grid operations. To the extent that SCE is aware of such an emergency, it may notify customers of a PTR event day.
- SCE System and Weather Conditions – As weather conditions are the primary driver in predicting system peaks, SCE will utilize forecasted temperature to trigger an event day.

More specifically, when the predicted temperature for the next day in downtown Los Angeles reaches 87 degrees or hotter, SCE may call a PTR event day. SCE will utilize the forecasted weather and its system load forecast to determine whether a PTR event day is warranted. If system reserves appear adequate (*e.g.*, a low generation "heat-rate" (BTU / kWh), then SCE may not call an event, even though the temperature trigger threshold has been met. This forecasted temperature trigger provides customers and the media with a simple, reliable method to anticipate PTR events.

As discussed above, the CAISO Electrical Emergency Alert is a statewide event upon which all three large investor-owned utilities will respond as required. SCE may adjust the trigger definitions and thresholds to accommodate efforts to develop a consistent, statewide event trigger.

2. Rebate

During PTR events, customers would earn a rebate of $0.66 / kWh for usage less than their customer specific reference level. The $0.66 / kWh rebate is based on the 2006 GRC long run avoided capacity cost of $75 / kW-year, adjusted for losses, the value of day-ahead call option, and the Loss of Load Probability (LOLP). In developing this rebate, SCE assumed a secondary service loss adjusted capacity cost which was de-rated due to the programs' limited availability (15 event days * 4 hours / event = 60 hours) and uncertainty associated with the day-ahead call. The resulting de-rated capacity value is allocated by LOLP to provide the summer on-peak plus winter mid-peak value.[26] The resulting derated capacity value was then divided into the 60 program hours to determine the PTR rebate of $0.66 / kWh.

3. Eligibility and Response Rate

100% of residential customers with Edison SmartConnect™ meters will be automatically eligible for the PTR program and customers will not be required to take any action to enroll in PTR. The estimated demand response associated with PTR uses the demand elasticities developed in the Statewide Pricing Pilot. SCE believes that a reasonable range for a PTR event awareness rate is 50% to 70%. See Appendix B for a more detailed discussion regarding PTR awareness and demand response rates.

4. Customer Specific Reference Level (CSRL)

Definition. The PTR rebate is based on a customer's usage reduction during peak periods of event days. The usage reduction is calculated by comparing actual usage to an estimate of usage that would have normally occurred during event hours on a critical peak day. This estimate of usage during the critical peak day is known as the customer specific reference level (CSRL). CSRL is compared to actual usage during peak hours of event days to calculate a customer's demand response and their associated rebate.

CSRL Objective. The development of a CSRL definition and methodology has the following objectives.[27]

- Simplicity, including ease of use, ease of understanding, and low costs for participant and operator to calculate the CSRL load profile and resulting savings.
- Accuracy, including lack of bias (*i.e.*, no systematic tendency to over- or under-state reductions), appropriate handling of weather-sensitive accounts, and verifiability.

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[26] Consistent with the methodology described in Appendix A of Rulemaking 07-01-041 Straw Proposals for Load Impact Estimation and Cost Effectiveness Evaluation of Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company filed on July 16, 2007 as part of R.07-01-041.

[27] Protocol Development for Demand Response Calculation – Findings and Recommendations, prepared for the California Energy Commission, February 2003, 400-02-017F, by KEMA-XENERGY, Miriam Goldberg and G. Kennedy Agnew.

- Minimization of the ability for customers to game or inflate their CSRL load profile.
- Predictability, or the ability for customers to know their CSRL before committing to a particular curtailment amount and event.
- Minimization of free-ridership.

Thus, the CSRL should accurately represent, to the extent possible, an estimate of each customer's usage during peak periods in the absence of a price incentive. Furthermore, predictability and the ability to know the CSRL in advance of a peak day are other factors to consider in the development of CSRL. Finally, the CSRL should be simple for customers to understand. Customers cannot be expected to respond to a program if they lack understanding of how their rebates are calculated.

Continuing CSRL Evaluation. Similar to the final dynamic rates, SCE will develop a CSRL definition to be evaluated as part of SCE's 2009 GRC Phase II proceeding. For the purposes of this filing, SCE has defined CSRL as the average 2 p.m. to 6 p.m. usage for the highest 3 of 5 previous weekdays (excluding holidays and previous event days).

SCE is currently evaluating several definitions of CSRL that best meet the objectives stated above. The following are some of the potential CSRL definitions that will be evaluated and a proposed definition will be included in SCE's Phase II GRC application.

- Highest 3 of 5 – Similar to SDG&E's customer reference level methodology,[28] under this method CSRL would be defined as the peak period usage during the highest 3 of 5 previous eligible non-event days.
- 5 Previous Eligible Days – Under this method, CSRL would be defined as the average 2 p.m. to 6 p.m. usage during the 5 previous eligible days (weekdays, excluding holidays and previous event days).

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[28] SDG&E Application No. 07-01-047, Exhibit No.: SDGE-13, Prepared Direct Testimony of Leslie Willoughby, dated January 31, 2007, pp. 4 to 10.

- 5 Previous Eligible Days Adjusted For Temperature – Same method as above, but adjusted for weather by analyzing a regression of on-peak usage as a function of temperature.
- Top 12 Days Same Month Previous Year – This method would define CSRL from the prior year's usage, and has the advantage of providing the CSRL prior to the event's occurrence. An alternative method would be necessary for new customers.

The development of an appropriate CSRL requires the balance between a simple, less accurate CSRL versus a complex, but more accurate CSRL. SCE will evaluate the potential CSRLs relative to the objectives stated above with the overarching goal of assisting customers' demand response.

CSRL Accuracy. As stated above, determining an appropriate CSRL to facilitate demand response involves a level of trade-offs. Furthermore, SCE expects to learn and gain new insights into the appropriate design of CSRL as the Edison SmartConnect™ project is implemented. Thus, SCE believes that it would be appropriate to periodically re-evaluate, as necessary, the CSRL methodology in a continuing process of improvement.

5. Customer Eligibility

As mentioned previously, PTR will be available for all bundled service residential customers, including those residential customers that participate in SCE's direct load control programs, including the Summer Discount Plan. Direct incentives for load control programs would be lower than provided today to account for PTR. Customers on a CPP rate are not eligible for PTR.

6. Bill Impacts

PTR is expected to have the following bill impacts, assuming no shift in usage.

Table A-7
PTR Bill Impacts for Non-CARE Customers

% Bill Impact	# of Accounts[29]	% of Accounts	Average OAT Rate (cents / kWh)	Average PTR + OAT Rate (cents / kWh)	% Impact
< 15%	495	0.0%	12.1	9.7	-20.0%
-10 to -15%	4,366	0.1%	12.3	10.8	-12.0%
-5% to -10%	54,972	1.8%	13.6	12.7	-6.3%
-2% to -5%	305,197	9.8%	14.4	14.0	-2.9%
-2% to -0.1%	2,293,428	73.8%	16.3	16.3	-0.5%
0% to -0.1%	447,790	14.4%	17.1	17.1	0.0%
> 0%	-	-	-	-	-
Total	3,106,248	100.0%	16.2	16.1	-0.7%

Table A-8
PTR Bill Impacts for CARE Customers

% Bill Impact	# of Accounts[30]	% of Accounts	Average OAT Rate (cents / kWh)	Average PTR + OAT Rate (cents / kWh)	% Impact
< 15%	2,656	0.3%	9.2	7.5	-18.3%
-10 to -15%	4,520	0.5%	8.8	7.8	-11.9%
-5% to -10%	24,303	2.5%	9.5	8.9	-5.9%
-2% to -5%	125,099	12.6%	10.1	9.8	-3.0%
-2% to -0.1%	735,588	74.3%	10.7	10.7	-0.6%
0% to -0.1%	97,513	9.9%	11.5	11.5	0.0%
> 0%	-	-	-	-	-

7. PTR Rebate Payments

Assuming a 20% load reduction, total annual PTR payments are expected to be approximately $68 million (based on SPP price elasticities, and "3 of 5" CSRL definition). These rebates will be included in the customer's next bill as a line item credit. Assuming no shift overall residential usage patterns, SCE expects PTR payments to be $27 million as a natural consequence of

[29] Customer counts shown above represent population counts using the original load research sampling weights, un-adjusted for sample attrition.

[30] *See id.*

individual customer usage reductions during the peak periods. In addition, a small number of customers will reduce usage, but not receive a rebate. This will also occur on a random basis due to a customer's activities on days which are taken into consideration in the CSRL calculation. For example, suppose a customer returns from vacation after a heat storm. During the next PTR event, that customer may reduce usage, but not to the point where a rebate is earned since usage is not below their CSRL established while they were on vacation. Due to its random nature it is not possible to eliminate this situation, although it is desirable to minimize its effects. While an initial estimate of credits will be estimated and accounted for in setting the residential rate levels to address any inter-rate group subsidization, subsequent revenue surpluses or deficits resulting from the PTR rate will be accounted for in SCE's annual Energy Resource Recovery Account (ERRA) filing.

C. Edison SmartConnect™ Thermostat Load Control Program

SCE proposes an Edison SmartConnect™ Thermostat program for all residential customers. The proposed Smart Thermostat program will provide for credits for participating in events setback the temperature 4 degrees on customers Title 24 compliant PCTs.

1. Program Summary

The proposed Edison Smart Thermostat Program with a PCT will have the following attributes:

- Enrollment. Customers will sign up into the SmartConnect™ Summer Discount Program and register their PCT with the Edison SmartConnect™ meter.
- Installation. Enrolled customers will be eligible to receive a $125 rebate for PCT equipment and installation costs. New construction or HVAC retrofits will not be eligible for the $125 rebate.
- Events. SCE may call up to 15 economic events and 5 reliability events per year. During an event, the PCT will be raised 4 degrees through the Edison SmartConnect™ meter. SCE estimated that 50% of the load drop will be shifting to off-peak hours.

- Event Notification. Advanced customer notification is not necessary since the thermostat will be controlled by SCE. However, the PCT will have a notification indicator so that customers will know that an event is occurring.
- SmartConnect™ Thermostat Program Participation Credit. All enrolled customers will be eligible to receive an annual incentive credit on their bill.
- Event Override. Participating program customers will be allowed to override up to 5 events per year at a predetermined charge per event.
- Participation. In conformance with anticipated Title 24 mandates, all new residential construction and residential HVAC retrofits will be required to install a PCT. Enrollment is voluntary and SCE assumes that 25% of customers subject to Title 24 will participate in the Edison SmartConnect™ Thermostat program.

2. Summary of Impacts and Benefits

The Edison Smart Thermostat Load Control Program for PCT customers is estimated to have a demand response impact of about 342 MW by 2013 and resulting nominal benefits of $1,127 million See Appendix B for detailed assumptions and methodologies.

D. Critical Peak Pricing (CPP) Rate Design

As detailed below, the CPP rates are event-based and are designed to be consistent with the proposed residential PTR program in terms of events, peak periods, triggers, and notification. CPP will be available to C&I (< 200 kW) and residential customers on an opt-in basis.

1. CPP Events

Under the CPP program, SCE may call a maximum of 15 events per year. These events may occur any time of year (*i.e.*, CPP events are not limited to the summer season); although SCE expects the large majority of the events to be called during the summer season from June to September.

During a CPP event, the CPP peak period will be from 2 p.m. to 6 p.m. Furthermore, based upon the SCE specific customer SPP load data from CPP-F and control customers, SCE estimated that 50% of the load drop will be shifting to off-peak hours. Even though there is expected to be a shift in usage, an analysis of SCE's system peak load profile demonstrates that the shift will occur without creating a new system peak in the shoulder periods (*i.e.*, the "rebound" effect").

Similar to PTR, CPP events will be called on a "Day Ahead" basis. Notification will begin by 3 p.m. the day before an event would be called. SCE expects to use voice messages, text messages and other appropriate communication channels to notify customers of CPP events. Similar to PTR, SCE will utilize a trigger mechanism to identify event days. CPP event days may be triggered by the occurrence of one or more of three pre-defined trigger mechanisms.[31]

2. CPP Rate and Assumptions

CPP Rate. From an economic standpoint, CPP is the "inverse" of PTR. That is, given certain assumptions, an informed customer would be indifferent to a CPP charge or a PTR rebate. Accordingly, the calculation of such charge and rebate would be the same. Thus, during CPP events, customers would be charged a tariff of $0.66 / kWh for usage in addition to their TOU or OAT rate.

CPP Rate Assumptions. Similar to the PTR rebate, the $0.66 / kWh tariff is based on the 2006 GRC long run avoided capacity cost of $75 / kW-year, adjusted for losses, the day-ahead value and Loss of Load Probability (LOLP). See PTR rebate section of this appendix for more information on the assumptions used in the development of the CPP charge. The CPP tariff is presented here for illustrative purposes. SCE requests that the final dynamic rate making be incorporated into SCE's 2009 GRC Phase II proceeding, which is expected to be filed in early 2008.

Revenue Neutrality. The CPP charges are expected to result in an estimated surplus of $115 million per year, which is based on the assumption that the customers will not change behavior during the CPP events. To maintain revenue neutrality, the estimated surplus is then divided by the non-event kWh to provide a rate reduction of $0.01 / kWh for usage during non-event periods. Any revenue surpluses or deficits resulting from the CPP rate will be offset in SCE's annual Energy Resource Recovery Account (ERRA) filing.

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[31] *See* PTR trigger discussion in Section B of this appendix, *supra.*

3. Participation

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. SCE assumed that those enrollment rates would be sustained over the full study period. Although the model provided a point estimate, the margin for error in this approach is significant. Utilizing this methodology, the opt-in CPP participation rate was estimated to be 25.3% of all medium C&I customers. Additionally, the actual number of respondents will increase in proportion to the meter installations.

4. Customer Eligibility

Small and medium C&I customers equipped with Edison SmartConnect™ meters are eligible to enroll in a CPP rate, including those who also participate in SCE load control programs. Similar to the CPP rate offered to large C&I (> 200 kW), the CPP will be available for Bundled Service Customers only. Furthermore, agriculture customers will not be eligible for CPP. These customers generally use off-peak loads with over 70% of agriculture customer usage already served on a TOU rate. Thus, relative to the much larger contributions from the rest of residential customers, demand response from agriculture customers is expected to be substantially less significant. Similarly, street lighting customers have off-peak loads and are not expected to be able to provide significant demand response. Thus, SCE will not make the CPP program available to street lighting customers. Residential customers on the CPP rate will not be eligible for the PTR program.

5. Bill Impacts

CPP for medium C&I customers (20 kW to 200 kW) is expected to have the following bill impacts, assuming no shift in usage.

Table A-9
Bill Impacts for Medium C&I Customers

% Bill Impact	# of Accounts[32]	% of Accounts	Average OAT Rate (cents / kWh)	Average CPP + OAT Rate (cents / kWh)	% Impact
< 10%	-	-	-	-	-
-5% to -10%	3,333	2.9%	12.0	11.2	-5.9%
-2% to -5%	15,796	13.5%	12.8	12.5	-2.7%
-2% to -0.1%	38,049	32.5%	13.0	12.9	-1.0%
0% to -0.1%	2,515	2.2%	13.2	13.2	0.0%
0% to 2%	35,441	30.3%	13.7	13.8	1.0%
2% to 5%	19,456	16.6%	15.3	15.8	3.0%
5% to 10%	2,252	1.9%	17.9	19.0	6.1%
10% to 15%	82	0.1%	22.9	25.5	11.3%
> 15%	-	-	-	-	-
Total	116,924	100.0%	13.5	13.5	0.0%

SCE's bill impact analysis above shows that for GS-2 C&I customers, approximately 2.0% will experience annual bill increases of more than five percent, while about 2.9% will experience a bill decrease of more than five percent, assuming no load response and fifteen events called. In other words, absent any demand response, bill impacts for 95.1% of GS-2 customers will be limited to within plus or minus five percent. Assuming a ten percent load reduction response, 0.1% of customer will experience annual bill increases of at least nine percent, while 2.9% will experience a bill decrease of at least five percent.

E. Time of Use (TOU) Rate Design

As detailed below, SCE's TOU rates are non-event based and are designed to be consistent with the other dynamic rates and demand response programs, including PTR and CPP.

1. Residential

a) Rates

SCE's illustrative non-CARE[33] residential TOU rates are as follows.[34]

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[32] *See* fn. 27, *supra*.

Table A-10
Illustrative Non-CARE Residential
TOU Rates[35]

Summer On-Peak	$0.63
Summer Off-Peak	$0.25
Winter On-Peak	$0.24
Winter Off-Peak	$0.20

For comparative purposes, SCE's OAT residential rates are as follows:

Table A-11
Residential Rates from Schedule D:
Domestic Service[36]

Tier 1	$0.12
Tier 2	$0.14
Tier 3	$0.22
Tier 4	$0.26
Tier 5	$0.29

In deriving the TOU energy rates, SCE first estimated the TOU generation marginal energy and capacity costs revenue from 2 p.m. to 6 p.m. by multiplying the estimated TOU unit marginal cost prices pertaining to energy and analyzed capacity from 2 p.m. to 6 p.m. by the TOU

Continued from the previous page

33 The California Alternate Rates for Energy (CARE) Program offers income-qualified customers a 20% discount off their monthly bills. Enrolled customers are also exempt from the 2001 rate increases ordered by the California Public Utilities Commission.

34 SCE's AB1-X compliant TOU tariff is presented above for illustrative purposes. SCE requests that the final AMI rate making be incorporated into SCE's 2009 GRC Phase II proceeding, which is expected to be filed in early 2008.

35 Illustrative Non-CARE residential TOU rates are designed to be revenue neutral to Tiers 3, 4, and 5 of the residential schedule D rates (OAT).

36 Schedule D rates effective as of 1/1/07.

usage during the same time period. Once the TOU generation marginal cost revenue was estimated, SCE allocated the total generation revenue at usage greater than 130% of baseline on the basis of the TOU generation marginal cost revenue as described. The resulting allocated generation revenue by the TOU period is then divided by the corresponding kWh consumption to derive the TOU energy charge at usage greater than 130% of baseline. Finally, the TOU SCE generation charges at usage greater than 130% of baseline are obtained by subtracting out the DWR power charge

The TOU peak period will be consistent with the proposed PTR peak period which is from 2 p.m. to 6 p.m. In addition, consistent with the SPP, SCE has assumed no change in energy usage for TOU customers. As stated in the Impact Evaluation of the California Statewide Pricing Pilot, Final Report, March 16, 2005, prepared by Charles River Associates, "There was essentially no change in total energy use across the entire year based on average SPP prices. That is, the reduction in energy use during high-price periods was almost exactly offset by increases in energy use during off-peak periods."

b) Enrollment Rate

Based on an analysis of bill impacts, SCE estimated that 5.5% of customers would opt-in to the TOU rate. To determine this percentage, SCE estimated that customers that could reduce their bill by 10% or more would opt-in to TOU. Based on an analysis of bill impacts, before load shifting 10% of all residential customers would be able to save 10% or more by adopting a TOU rate. Furthermore, 55% of all residential customers would potentially benefit from TOU.[37] Thus, an estimated 5.5% of all residential customers are estimated to opt-in to TOU (55% times 10% = 5.5%)

As stated previously, because of AB1-X constraints, 45% of residential customers will not be incented to enroll in TOU rates. For the purpose of this business case, the actual number of enrollees will increase in proportion to the meter installations.

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37 SCE Regulatory Policy and Affairs' analysis of 2005 domestic usage showed that approximately 45% of customers never received a bill containing any Tier 3 charges. Thus, the remaining 55% of residential customers are not protected by AB1-X, and could potentially benefit from a TOU rate.

c) Customer Eligibility

All residential customers are eligible for TOU, including those that are enrolled in the CARE program. Furthermore, residential customers that participate in SCE's direct load control programs will also be eligible to participate in TOU.

d) Bill Impacts

Estimated bill impacts were produced from SCE's 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. Residential TOU is expected to have the following bill impacts, assuming no shift in usage.

Table A-12
TOU Bill Impacts for Non-CARE Residential Customers

% Bill Impact	# of Accounts[38]	% of Accounts	Average OAT Rate (cents / kWh)	Average TOU Rate (cents / kWh)	% Impact
< 15%	16,819	0.5%	23.8	19.8	-16.9%
-10 to -15%	38,632	1.2%	22.5	19.7	-12.6%
-5% to -10%	157,371	5.1%	20.3	18.8	-7.3%
-2% to -5%	238,901	7.7%	17.8	17.2	-3.5%
-2% to -0.1%	527,205	17.0%	15.0	14.9	-0.8%
0% to -0.1%	908,443	29.2%	12.2	12.2	0.0%
0% to 2%	355,917	11.5%	15.7	15.9	1.1%
2% to 5%	363,038	11.7%	16.1	16.6	3.5%
5% to 10%	361,992	11.7%	15.9	17.1	7.1%
10% to 15%	127,325	4.1%	15.7	17.5	11.9%
> 15%	10,605	0.3%	15.8	18.3	15.7%
Total	3,106,248	100.0%	16.2	16.2	0.0%

[38] *See* fn. 27, *supra*.

Table A-13
TOU Bill Impacts for CARE Residential Customers

% Bill Impact	# of Accounts[39]	% of Accounts	Average OAT Rate (cents / kWh)	Average TOU Rate (cents / kWh)	% Impact
< 15%	1,810	0.2%	12.2	10.4	-15.1%
-10 to -15%	24,806	2.5%	12.8	11.2	-12.3%
-5% to -10%	114,213	11.5%	11.8	10.9	-7.1%
-2% to -5%	129,166	13.1%	10.5	10.2	-3.2%
-2% to -0.1%	117,148	11.8%	10.3	10.2	-0.9%
0% to -0.1%	352,505	35.6%	8.6	8.6	0.0%
0% to 2%	75,553	7.6%	10.4	10.5	1.1%
2% to 5%	42,935	4.3%	10.7	11.0	3.6%
5% to 10%	78,220	7.9%	11.4	12.3	7.0%
10% to 15%	36,593	3.7%	11.8	13.3	12.6%
> 15%	16,730	1.7%	11.8	14.0	18.8%
Total	989,679	100.0%	10.7	10.7	0.0%

The results of SCE's non-CARE TOU rate design and residential bill impact analysis above shows that without any load reduction during peak periods, the number of residential customers experiencing at least a ten percent increase is 4%. For these customers, more than 23% of their usage consists of summer on-peak usage above tier 2, compared to approximately 17% for the all residential customers. The number of non-CARE customers experiencing at least a ten percent decrease is 1.7%. Assuming a ten percent load shift response, 7% of customers will experience annual bill decrease of at least eight percent, while 4% will experience a bill increase of at least ten percent.

2. Commercial and Industrial

As detailed below, the C&I TOU program was designed to complement the CPP program and be consistent with the TOU programs offered to other rate classes. In summary, medium C&I (20 kW to 200 kW) customers will be defaulted to the TOU rate, and have the choice to opt back into the GS-2 rate. In addition, small C&I customers (< 20 kW) will remain on GS-1, and will continue to have the option to enroll in a TOU rate.

[39] *See id.*

a) Rates

Consistent with the current TOU rates offered to these rate classes, the summer season will be defined as 12:00 a.m. on the first Sunday in June and continue until 12:00 a.m. of the first Sunday in October of each year. Furthermore, consistent with current summer TOU peak periods for these rate classes (TOU-8, TOU-GS-1 and GS-2-TOU), peak periods will be from 12 p.m. to 6 p.m. weekdays, except holidays.

- On-Peak: Noon to 6:00 p.m. summer weekdays except holidays
- Mid-Peak: 8:00 a.m. to Noon and 6:00 p.m. to 11:00 p.m. summer weekdays except holidays, 8:00 a.m. to 9:00 p.m. winter weekdays except holidays
- Off-Peak: All other hours.

The Time-Of-Use (TOU) energy rates are derived by allocating the total energy generation revenue of the OAT schedule on the basis of the TOU generation revenue of the current Optional TOU schedule. The resulting allocated generation revenue are divided by the corresponding TOU kWh to obtain the TOU charge on a $/kWh basis, then the TOU SCE generation for the charges are obtained by subtracting out the DWR power charge. SCE will update the TOU studies in its Phase II of the 2009-GRC. SCE's illustrative C&I TOU rates are as follows:

Table A-14
Illustrative Medium C&I TOU
Energy Rates

Summer On-Peak	$0.11
Summer Mid-Peak	$0.09
Summer Off-Peak	$0.07
Winter Mid-Peak	$0.09
Winter Off-Peak	$0.07

Additionally, for medium C&I customers, the demand charge associated with facilities is $8.60 / kW, and the summer on-peak demand charge is $18.79 / kW.

Table A-15
Illustrative Small C&I TOU Rates

Summer On-Peak	$0.20
Summer Mid-Peak	$0.17
Summer Off-Peak	$0.13
Winter Mid-Peak	$0.17
Winter Off-Peak	$0.13

The TOU rates were designed to be revenue neutral to the OAT. Furthermore, SCE's TOU rates presented above for illustrative purposes. SCE requests that the final dynamic rate making be incorporated into SCE's 2009 GRC Phase II proceeding, which is expected to be filed in early 2008.

b) Participation Rate

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. SCE assumed that those enrollment rates would be sustained over the full study period. Although the model provided a point estimate, the margin for error in this approach is significant.

Utilizing this methodology, the default TOU participation rate was estimated to be 51.3 percent for medium C&I customers. Additionally, the actual number of respondents will increase in proportion to the meter installations. See Appendix B for more information.

c) Customer Eligibility

Small and medium C&I customers equipped with Edison SmartConnect™ meters are eligible to participate in the TOU program including those who also participate in the A/C cycling program. Similar to the CPP rate offered to large C&I (> 200 kW), the CPP will be available for Bundled Service Customers only. Furthermore, Agriculture customers will not be eligible for TOU rates described above. These customers generally use off-peak loads and over 70% of the agriculture usage is currently on a TOU rate. Similarly, street lighting customers have off-peak loads and already have their own rate schedules. Thus SCE will not make the TOU program available to street lighting customers.

d) Bill Impacts

Estimated bill impacts were produced from SCE's 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. TOU for medium C&I customers is expected to have the following bill impacts, assuming no shift in usage.

Table A-16
TOU Bill Impacts for GS-2 Customers

% Bill Impact	# of Accounts[40]	% of Accounts	Average OAT Rate (cents / kWh)	Average TOU Rate (cents / kWh)	% Impact
< 10%	-		-	-	
-5% to -10%	2,594	2.2%	12.3	11.5	-6.4%
-2% to -5%	16,739	14.3%	11.8	11.5	-2.7%
-2% to -0.1%	35,431	30.3%	12.8	12.7	-1.0%
0% to -0.1%	2,489	2.1%	13.2	13.3	0.0%
0% to 2%	39,279	33.6%	14.2	14.4	1.1%
2% to 5%	20,299	17.4%	15.7	16.1	2.9%
5% to 10%	93	0.1%	17.9	18.9	5.8%
> 10%	-		-	-	
Total	116,924	100.0%	13.5	13.5	0.0%

The results of SCE's TOU rate design and GS-2 bill impact analysis above shows that without any load shift during peak periods, the number of medium C&I customers experiencing at least a five percent annual bill increase is 0.1%. Similarly, only 2.2% of customers will receive a bill decrease of more than five percent. Assuming a ten percent load reduction shift response, 17% of customer will experience annual bill decrease of at least three percent, while 0.1% will experience a bill increase of at least four percent.

[40] *See* fn. 27, *supra*.

e) Commodity Revenues

The illustrative TOU and CPP structures shown in this volume have been designed to be revenue-neutral assuming no customer demand response. In general, energy revenue shortfalls resulting from demand response would be contained within SCE's generation rate component. As such, Direct Access (DA) and future Community Choice Aggregation (CCA) customers would be exempt from cost recovery of ERRA revenue shortfalls caused by the demand response rates. Revenue over- or under-collections associated with the PTR rebates, TOU, or CPP rate design, would flow through SCE's ERRA balancing account in the same way as other revenues from the generation portion of the standard tariffs.

F. Measurement and Reporting

SCE will perform certain measurement and reporting activities as a result of its demand response programs. The following activities will assist SCE in quantifying the demand response impacts, refining forecasts of future demand response, and analyzing the effects of any potential program modifications.

Tracking and reporting of monthly demand response. SCE will analyze interval load data and, if requested, will provide reports to the Commission in order to assist in quantifying the demand response benefits and to refining estimates of future demand response. These reports may be provided for all CPP and PTR events, including number of customers that participate, estimated demand response achieved on event days, and comparison of actual & forecasted demand response.

Tracking and reporting of annual demand response. SCE will analyze annual interval load data and, if requested, will provide demand response information, including a summary of demand response, participation rates, the distribution of demand response within each major rate class, and a comparison of actual & forecasted demand response. To the extent possible, SCE may also provide an assessment of customer segment impacts, end-uses, and technological impacts. SCE expects that the annual demand response evaluation reports will evolve as these programs develop.

Performing an annual evaluation of Customer Specific Reference Level. As discussed in Chapter III, the customer specific reference level will be analyzed to evaluate effectiveness in terms of providing relevant information that can be acted upon, providing timely information, reducing "gaming", and reducing the potential revenue deficit / surplus.

Performing customer satisfaction and post event surveys. Periodically SCE may perform customer satisfaction and post-event surveys. These surveys may gauge customer response and acceptance of the various demand response programs. Potential survey topics may include an assessment of the understanding of rates, "fairness" of rates, satisfaction with rates, specific actions taken in repose to rates, source from where the customer was informed of an event day,

Furthermore, SCE may also survey customers to gauge the response to potential future programs. Such topics may include participant interest in other forms of dynamic rates, and interest in enabling technology, such as PCTs.

Appendix B

Program Impacts and Critical Assumptions

The purpose of this Appendix is to provide and overview of the estimated MW and avoided cost impacts from SCE's anticipated demand response programs that are enabled by Edison SmartConnect™. This Appendix also discusses the significant assumptions used in the demand response calculation, such as participation rates, price elasticity, and avoided capacity costs. For the purposes of this Appendix, PTR is included in the dynamic rate discussion as the calculation of impacts is similar to the dynamic pricing impacts calculations.

A. Dynamic Rate and PTR Impacts (MW)

1. Overview

This section presents the MW demand response results from residential and C&I customers. This section is divided into an overview, residential impacts, and C&I impacts, and includes a discussion on participation rates, price elasticities, average use, and other assumptions.

a) Key Drivers

Similar to SDG&E's AMI application and as outlined in the ALJ's decision on the SDG&E AMI settlement Agreement 39, the key drivers of SCE's demand response benefits are:

- Average energy use per customer by time period before being exposed to a new tariff
- Price responsiveness (as summarized by price elasticities)
- The number of customers who choose a tariff or are exposed to the price signal
- The difference between the new price and the old price by rate period
- The value of avoided capacity costs

b) Methodology

In summary, to calculate demand response for each of its programs, SCE:

- Developed revenue neutral rates (based on marginal cost) for each program;
- Used these rates to develop customer bill impacts;

- Developed participation rates based on the bill impacts;
- Applied Statewide Pricing Pilot[41] (SPP) demand elasticity, adjusted for differences in climate and central air conditioning saturation, to calculate average customer impacts;
- Used per customer impacts and participation rates to calculate demand response in MW; and
- Used generation avoided capacity costs to calculate demand response benefits in terms of avoided costs.

c) Demand Response Calculation

Demand response was calculated separately for the following items:

- Residential – PTR
- Residential – Opt-in TOU
- Small Commercial and Industrial – Opt-in CPP
- Small Commercial and Industrial – Opt-in TOU
- Medium Commercial and Industrial – Default TOU
- Medium Commercial and Industrial – Opt-in CPP

Additionally, SCE took into consideration those customers with central air conditioning (CAC) and customers enrolled in the CARE program. Rather than utilizing customer averages, SCE segregated the residential class to more precisely calculate demand response. Customers were bifurcated into those with CAC and those without CAC. These customers were further segregated into those on the CARE program, and those not on the CARE program. These four groupings (CAC and CARE, CAC and non-CARE, non-CAC and CARE, and non-CAC and non-CARE) were used to calculate average per customer impacts and demand response as described previously.

[41] The Statewide Pricing Pilot (SPP) was a pricing research project designed to estimate the average impact of time-varying rates on energy use by rate period for residential and small commercial and industrial customers. The SPP was authorized in D.03-03-036.

d) Summary Results

In summary, the demand response impacts from the dynamic rates are 132 MW and the impacts from PTR are 410 MW by 2013. Approximately 76% of these demand response benefits are provided by residential customers. The remaining benefits are the result of actions from the medium C&I customers. The following table summarizes the demand response benefits during the deployment period (2000-2012) and the first full year after deployment (2013).

Table B-17
Dynamic Pricing and PTR Demand Response (MW)

Year	Dynamic Pricing Benefits (MW)[42]	PTR Benefits (MW)	Total Demand Response (MW)
2009	12	0	12
2010	54	167	221
2011	93	296	389
2012	122	389	511
2013	131	410	541

2. Residential Dynamic Rate and PTR Impacts

a) Demand Response Summary

As a result of the dynamic pricing programs, demand response from residential customers is estimated to be 414 MW by 2013. Of this amount, PTR accounts for the majority of the demand response with 410 MW, while TOU accounts for 4 MW.

b) Average Use Under Existing Tariff

SCE estimated the existing average energy use by climate zone and rate period for residential and GS-1 customers from SCE's 2005 load research data. SCE's average energy use assumptions are shown in the figure below. On-Peak refers to 2 p.m. to 6 p.m. and Off-Peak refers to all other hours.

[42] Includes benefits from the following dynamic rates: residential TOU, medium C&I CPP and medium C&I TOU.

Table B-18
Existing Average Energy Use (kWh) by Class and SCE Climate Zone

		CPP Day		Non-CPP Day	
	Climate Zone[43]	On-Peak	Off-Peak	On-Peak	Off-Peak
Non-CARE / CAC	2	2.17871	1.23814	1.21938	0.85547
	3	3.20308	1.63688	1.77623	1.02054
	4	3.43190	2.06692	2.21325	1.32445
Non-CARE / No-CAC	2	0.59741	0.56629	0.54685	0.53113
	3	0.84031	0.66438	0.68154	0.56633
	4	0.93666	0.72857	0.81981	0.60732
CARE / CAC	2	1.73977	1.15415	1.08852	0.85346
	3	2.50987	1.30739	1.41810	0.84968
	4	2.72887	1.50089	1.65571	0.91665
CARE / No-CAC	2	0.51655	0.48257	0.46546	0.44362
	3	0.84471	0.73499	0.69884	0.60453
	4	1.33513	1.06742	1.14050	0.84976

c) Participation Rates

For the purposes of this discussion, the following definitions are provided.

- "Participation Rate" is a generic term that refers to the ratio of customers who choose a tariff or are exposed to a price signal. Thus, by definition, "Participation Rate" includes both "Enrollment Rate" and "Awareness Rate."
- "Enrollment Rate" is defined as the percentage of customers who sign up for or are defaulted to a given program.

[43] Climate Zone 2 (Mild) = Baseline zones 10 (Coastal Area) and 16 (Mountains (elevations above 3,000 feet)). Climate Zone 3 (Moderate) = Baseline zones 13 (Southern San Joaquin Valley) and 17 (Los Angeles Inland area). Climate Zone 4 (Hot) = Baseline zones 14 (Southern California High Desert) and 15 (Southern California Low Desert). A map of SCE's baseline zones can be found at SCE's tariff book.

- "Awareness Rate" is defined as the percentage of customers who become knowledgeable about a rate change (such as a PTR event) prior to its occurrence.

Since all residential customers are eligible for PTR participation, the use of an awareness rate is appropriate for PTR. For other TOU rates, such as the opt-in TOU described later in this testimony, distinctions between enrollment rate and awareness rate have been assumed to be negligible, as TOU is a year round program and customers have become aware of the peak and off-peak periods upon opting into the tariff. For CPP rates, both enrollment rates and awareness rates are determining factors for demand response. Since SCE is relying on the SPP results to estimate demand responsiveness, it assumes the same customer awareness of CPP events as was experienced in the pilot.

(1) Peak Time Rebate (PTR) Program

Enrollment Rate - As described in Chapter III, all customers with Edison SmartConnect™ meters will be automatically enrolled in the PTR program. Thus, the enrollment rate will increase during the deployment period as SmartConnect™ metes are installed and will reach 100% at the end of the deployment period in 2012.

Awareness Rate - In its AMI application, SDG&E assumed a 70% awareness rate. In response to SDG&E's application, the ALJ, DRA, and UCAN all noted that a PTR is not a CPP, and consumers may behave differently to those programs. Subsequently, as described in SDG&E's AMI decision, the DRA recommended a 50% awareness rate which was confirmed by the ALJ in her proposed decision.

As there have not been any significant studies performed on awareness rates, awareness rates are an estimate largely based on professional judgment. Furthermore, on the whole, there do not seem to be any significant factors that would differentiate the awareness rates between SDG&E and SCE (*e.g.*, both programs are based on similar principles, have similar program attributes, and will have a comprehensive notification program).

Utilizing the SDG&E and DRA arguments in SDG&E's application, an awareness rate of 50% to 70% appears to be reasonable. Given the attributes of its specific program, SDG&E believed that 70% was an appropriate estimate of the awareness rate of its customers. More specifically, individualized information (*e.g.*, email, text messages, their website, and word-of-mouth), combined with mass media outlets (*e.g.*, radio, news broadcast, radios ads, *etc.*) would produce a 70% awareness rate amongst its customers.

(2) SCE's PTR Adjustment

SCE also understands that arguments can be made for other awareness rates. Although a 70% awareness rate is reasonable, a 50% awareness rate is conservative. SCE uses a conservative estimate for awareness rates to compensate for the assumption that price elasticities for a rebate and a rate change are the same, as was proposed in the SDG&E application and adopted by the ALJ in the proposed decision. SCE believes that the elasticities for a rebate could be lower than for a rate but there is no empirical evidence on this to date. The following table demonstrates the impacts of the awareness rate on overall demand response by 2013.

- Scenario A: PTR DR with 70% awareness = 574 MW
- Scenario B: PTR DR with 60% awareness = 493 MW
- Scenario C: PTR DR with 50% awareness = 410 MW

(3) Time-Of-Use

Time-of-Use (TOU) rates will be offered on an opt-in basis. TOU peak and off-peak periods will be available all year, as opposed to PTR programs which will be called only during 2 p.m. to 6 p.m. during certain event days. Thus, customers that have taken action to enroll in the program have been assumed to be aware of and respond to the peak and off-peak price signals.

Based on an analysis of bill impacts, SCE estimated that 5.5% of customers would opt-in to the TOU rate. To estimate the participation rate, SCE first estimated that customers that would have a bill reduction of 5% without a change in usage. Based on bill impacts, approximately 10% of all residential customers would be able to save 10% or more by adopting a TOU rate. Furthermore, 54.8% of all residential customers are eligible for TOU. Thus, an estimated 5.5% of all residential customers are estimated to opt-in to TOU (54.8% times 10% = 5.5%).

d) Price Elasticity

(1) SPP Elasticity

Charles Rivers Associates (CRA) used econometric models to derive price elasticities from data collected in the SPP. Two summary measures of price response used in this analysis are the elasticity of substitution between peak and off-peak consumption (which measures changes in customer load shapes, holding daily consumption constant) and the price elasticity of daily electricity consumption (which measure changes in daily consumption, holding the load shape constant). As described above, the elasticities used in the analysis are largely based on the SPP analysis. The SPP statewide elasticities are found in Table 5 of the CRA March 16, 2005 report and are summarized in the figure below for SCE climate zones.

The SPP econometric demand models were based on a CPP-F rate. From an economic standpoint, the average customer would be indifferent to either a rate structure containing a PTR rebate or a CPP charge since one would expect the customer to respond to the opportunity cost of peak consumption. In either case, the rates would be designed to be revenue neutral and any surplus or deficiency would receive balancing account treatment. Thus, assuming that the marginal prices between the programs are the same (*i.e.,* PTR with $0.66 rebate and CPP with $0.66 charge), customers would have similar response in either of the two programs. Thus, SCE has utilized the SPP's CPP-F price elasticities in estimating its PTR demand response. This assumption is similar to what was recommended by the ALJ in her proposed decision in the SDG&E AMI Application.[44]

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[44] *See* fn. 4, *supra*.

Table B-19
Residential CPP-F Rate Elasticity Estimates Statewide, All Summer Averages

Climate Zone	Elasticity of Substitution		Daily Price Elasticity		
	CPP Days	Non-CPP Days	CPP Days	Non-CPP Days	Weekend Days
2	-.061	-.055	-.042	-.044	-.018
3	-.102	-.093	-.043	-.047	-.026
4	-.113	-.105	-.032	-.039	-.020

Statewide SPP elasticity can be adjusted to account for SCE's customer base as described in the following section.

(2) Adjustments to SPP Price Elasticities

To determine price elasticities for SCE, adjustments were made based on the weather conditions (see figure below) and the central air conditioning (CAC) saturations representative of SCE populations in Climate Zones 2, 3, and 4 (see figure below). In addition, certain other adjustments were made to the econometric models to reflect the characteristics of SCE's specific dynamic pricing program and SCE's customers.

Climate - The population weighted average weather for 2000 (determined to be a normal year) in SCE's service territory was used.

Table B-20
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

CAC Saturation - SCE made adjustments for central air conditioning (CAC) saturations within its customer base. In order to obtain more accurate per customer impact estimates, SCE calculated the impacts separately for its CAC and Non-CAC customers rather than relying on average CAC saturations.

Table B-21
SCE Central Air Conditioning Saturations

Climate Zone	CAC Saturation (Percent)
2	21.2%
3	57.8%
4	60.9%
All	41.9%

With the guidance from the SPP consultants, Charles River Associates, and the Pricing Impact Simulation Model (PRISM) tool, SCE derived load reductions for customers in its service territory by making adjustments for central air conditioning saturation and cooling degree hours. SCE utilized the on-peak, non-CPP Day impact estimates as a proxy for TOU and the on-peak CPP Day impact estimate for PTR.

<u>CARE</u> - In addition to CAC saturation, the Residential population was further segmented into CARE and non-CARE customers due to substantial differences in CARE and Non-CARE rates. This results in four groups. Non-CARE w/ CAC, Non-CARE w/out CAC, CARE w/CAC and CARE w/out CAC.

<u>Outer and Inner Summer Elasticity</u> - The SPP calculated elasticities for three summer periods, “inner summer,” “outer summer,” and “all summer.” “Inner summer” included July through September, “outer summer” included May, June and October and “all summer” included May through October. SPP consultants directed SCE to use the “inner summer” elasticity model because it most closely matches SCE’s current definition of summer, June through September.

<u>Peak Period</u> - The on-peak period was changed from 2 p.m. – 7 p.m. used in the SPP to 2 p.m. – 6 p.m. A ratio adjustment was used, where the ratio was calculated from hourly elasticities available in the Hourly Residential SPP Report. In particular, the Statewide Pricing Pilot Hourly Complex Model impacts were used to adjust the PRISM

impacts to the shorter on-peak period. PRISM created an average impact for the entire on-peak period. The SPP Hourly Complex Model provided a separate impact for each hour of the 2 p.m. – 7 p.m. on-peak period. SCE utilized the hourly to average ratio from the Hourly Complex Model to adjust the PRISM impacts in order to capture this hourly variation and appropriately adjust the PRISM impacts for the shorter on-peak period.

Table B-22
Actual PRISM Impacts

Non-CARE Customers with CAC					**Non-CARE Customers without CAC**			
Climate Zone	Impact Measure	PTR Rate	TOU Rate		Climate Zone	Impact Measure	PTR Rate	TOU Rate
2	Change (kWh/hr)	-0.400	-0.071		2	Change (kWh/hr)	-0.048	-0.011
	% Change	-18.34%	-2.97%			% Change	-7.96%	-1.13%
3	Change (kWh/hr)	-0.617	-0.102		3	Change (kWh/hr)	-0.078	-0.020
	% Change	-19.28%	-2.80%			% Change	-9.32%	-1.10%
4	Change (kWh/hr)	-0.654	-0.118		4	Change (kWh/hr)	-0.080	-0.026
	% Change	-19.06%	-2.91%			% Change	-8.53%	-1.13%

Load Forecast Adjustment to SPP Load Impacts - The per customer impacts used to estimate demand response MW were adjusted to account for modeling variation using a Monte Carlo simulation. The Monte Carlo Analysis allowed SCE to determine what load impact result from the SPP for SCE customers can be reasonably relied upon in the same way that it can rely on a combustion turbine (CT) operating.

The approximate forced outage rate of a CT is about five percent. As shown in the figure below, to treat the load response consistently, SCE used the lower end of the one-sided ninety-five percent confidence interval peak kW reduction. This is the value that will be available with ninety-five percent certainty when called upon, taking into account statistical modeling variability. The final PRISM and Monte Carlo adjusted per customer kW impacts for the Non-CARE PTR rate are shown in the figure below.

Table B-23
Monte Carlo Adjusted Impacts

Non-CARE Customers with CAC					**Non-CARE Customers without CAC**			
Climate Zone	Impact Measure	PTR Rate	TOU Rate		Climate Zone	Impact Measure	PTR Rate	TOU Rate
2	Change (kWh/hr)	-0.378	-0.066		2	Change (kWh/hr)	-0.042	-0.009
	% Change	-17.31%	-2.75%			% Change	-7.03%	-0.92%
3	Change (kWh/hr)	-0.583	-0.096		3	Change (kWh/hr)	-0.068	-0.017
	% Change	-18.20%	-2.64%			% Change	-8.06%	-0.94%
4	Change (kWh/hr)	-0.611	-0.112		4	Change (kWh/hr)	-0.066	-0.023
	% Change	-17.81%	-2.76%			% Change	-7.02%	-01.00%

e) Other Assumptions

Timing of Rates - SCE has assumed that PTR will be available in Fall 2009 and the number of program participates will ramp up during the meter installation phase which will occur from 2009 to 2012. Furthermore, SCE assumed that TOU rates will be available as the meters are installed and will ramp up from 2009 to 2012.

Elimination of Double Counting with Load Control Programs - Customers may participate in both PTR and SCE's load control programs. Thus, a potential double counting of demand response benefits may occur. To avoid double counting demand response and to develop a conservative estimate, load control customers have been removed from the population by subtracting those customers from the total residential population.

Furthermore, since the Summer Discount Plan currently exists, the demand response associated with that program should be "credited" to that program, and should not be included as demand response related to the Edison SmartConnect™ program. Thus, to remove A/C Cycling customers from the population of possible participants, the total number of Summer Discount Plan was subtracted from the residential segments with CAC.

3. Commercial and Industrial

Demand response from medium C&I customers is expected to be 140 MW by 2013. Of this amount, 49 MW is expected from TOU and 78 MW from CPP. Additionally, SPP pilot found that small C&I customers have no response to a CPP rate without enabling technology. Thus, SCE is not including demand response benefits from small C&I customers.

a) Average Use Under Existing Tariff

SCE estimated the existing average energy use by rate period for GS-2 and GS-1 customers from SCE's 2005 load research data (2005 is considered a normal weather year). SCE's average hourly kWh energy use assumptions by period are shown below.

Table B-24
Existing Average Energy Use -Medium C&I

	Non-CPP Day kWh/hour			
	On-Peak	Mid-Peak	Off-Peak	CPP
GS-2 / 20-100 kW	19.62	15.07	9.02	24.42
GS-2 / 100-200 kW	81.21	64.63	41.40	100.65

	CPP Day			
	On-Peak	Mid-Peak	Off-Peak	CPP
GS-2 / 20-100 kW	22.25	17.14	10.00	27.64
GS-2 / 100-200 kW	89.54	71.67	45.60	110.78

Table B-25
Existing Average Energy Use – Small C&I

	On-Peak	Mid-Peak	Off-Peak	CPP
Non-CPP Day	2.34	1.62	0.93	2.92
CPP Day	2.00	1.40	0.85	2.50

b) Participation Rates

TOU - TOU will be provided on a default basis to medium C&I customers. The medium C&I participation rates were determined by the Momentum Market

Intelligence (MMI) simulation model which were consistent with the results from the SPP. The MMI model estimated that 46.5% of medium C&I customers would remain on the default TOU rate.

CPP - CPP will be provided to medium C&I customers as an optional program. The participation rates were also determined by the Momentum Market Intelligence model and estimated to be 25.3%.

c) Price Elasticity

(1) CPP and TOU Elasticity

SPP Elasticity - Similar to residential price elasticities, the econometric models utilized for C&I customers were developed by CRA derived from statewide observations in the SPP. Furthermore, the SPP econometric models were based on the CPP-F rate. The following table shows the SPP estimates of the elasticity of substitution for participants.[45]

Table B-26
SPP Estimates of the Elasticity of Substitution for Participants

	Elasticity of Substitution – CPP Days	t-statistic	Elasticity of Substitution – Non-CPP Days	t-statistic
Small C&I	-0.0050	-.045	0.0255	1.23
Medium C&I	-0.0412	-4.79	-0.0493	-3.10

(2) SCE Adjustments to SPP Price Elasticities

Similar to the SPP price elasticity adjustments made for PTR, SCE utilized SPP demand models and made the following adjustments.

Load Forecast Adjustment to SPP Load Impacts - Similar to the adjustment made for residential loads, SCE adjusted the load forecast to SPP load impacts for commercial loads. The per customer impacts used to estimate demand response MW were adjusted to account for modeling variation using a Monte Carlo simulation. The Monte Carlo

45 *See* fn. 9, *supra*.

analysis allowed SCE to determine what load impact result from the SPP for SCE customers can be reasonably relied upon in the same way that a combustion turbine (CT) can be relied upon. The C&I PRISM impacts and Monte Carlo adjusted impacts are below.

Table B-27
PRISM and Monte Carlo Adjusted Impacts

	CPP	CPP % Impact	TOU	TOU % Impact
Actual PRISM Impacts	-7.43	6.7%	-3.06	3.4%
Monte Carlo Adjusted Impacts	-5.72	5.2%	-2.34	3.3%

PRISM Model - In addition, because enabling technologies are not currently offered as part of the Commercial and Industrial dynamic rates, the non-technology PRISM model was used. The non-technology model has lower elasticities than either the blended model or the technology model. SCE believes this approach is conservative and justified.

B. Load Control Impacts (MW)

SCE's SmartConnect™ infrastructure enables communication with PCTs that are designed for load control under the proposed Title 24 building code. SCE proposes to enroll customers in an Edison SmartConnect™ Thermostat program in two ways. First SCE will take advantage of the implementation of the Title 24 building code standard beginning in 2009.

1. Summary Results

In summary, the demand response impacts by 2013 from the Edison SmartConnect™ PCT load control programs are 342 MW. These impacts are incremental to SCE's estimated benefits from the existing Summer Discount Plan of 1,559 MW in 2013. All of the demand response benefits from load control programs are provided by residential customers. The business case as filed does not consider benefits as a result of actions from the medium C&I customers. The following table summarizes the benefits during the deployment period (2009 to 2012) and for the first full year after deployment (2013).

Table B-28
Load Control Demand Response (MW)

Year	Title 24 Smart Thermostat Program (MW)	Non-Construction Title 24 Smart Thermostat Program (MW)	Total Demand Response (MW)
2009	13	9	22
2010	37	38	75
2011	62	89	151
2012	89	155	244
2013	117	225	342

2. Participation Rates

For the purposes of this discussion, the following definitions are provided.

- "Participation Rate" is a generic term that refers to the ratio of customers who choose a tariff or are exposed to a price signal. Thus, by definition, "Participation Rate" includes both "Enrollment Rate" and "Awareness Rate."
- "Enrollment Rate" is defined as the percentage of customers who sign up for or are defaulted to a given program.

3. Construction Building Code Compliance

According to the proposed Title 24 building code, Residential New Construction customers, SCE assumes that 84% of potential new construction will contain a central air conditioning unit.[46] In order to pass building inspection, the builder will need to install a Title 24 compliant PCT. The annual enrollment rate into the Smart Thermostat program for New Construction customers with an Edison SmartConnect™ meter is assumed to be 25%.

For Title 24 Residential Retrofit customers, SCE assumes that 85,000 residential single and multi-family homes have an HVAC replacement or retrofit per year.[47] Furthermore, the percentage of residential customers who obtain a permit to replace their central HVAC system and therefore install a Title 24 compliant PCT is assumed to be 50%. The annual

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[46] Residential Appliance Saturation Survey.

[47] Duct-System Replacement Final Report, March 31, 2004.

enrollment rate into the Smart Thermostat program for Title 24 Residential Retrofit customers with an Edison SmartConnect™ meter is assumed to be 25%.

4. Non-Construction Customer Enrollment

For all other residential customers, SCE would offer rebates to those who purchase and install a Title 24 compliant PCT without being subject to building code requirements (*i.e.*, not a new home or HVAC retrofit) and who enroll in SCE's Smart Thermostat Program. These customers will receive a rebate toward the purchase and installation of a Title 24 compliant PCT. Based on SCE's experience with the current Summer Discount Plan, SCE is targeting an annual enrollment of 60,000 non-construction customers with an Edison SmartConnect™ meter into the Smart Thermostat Program from 2009 to 2032. To be conservative, SCE has capped the cumulative enrollment at 250,000 customers.

5. MW Calculation

The MW are calculated based on the kW reduction per customer and number of air conditioning units for a residential customer. Based on SCE experience with the Summer Discount Plan, SCE assumes that 1 kW[48] is reduced during a SCE Smart Thermostat event during the 4 hours the PCT is set back 4 degrees. Furthermore, SCE assumes residential customers on the existing Summer Discount Plan have 1.2 central air conditioning units per household. To calculate the MW avoided from customers on the Edison Smart Thermostat program, SCE used the mid year customer cumulative enrollments multiplied by 1.2[49] central air conditioners and 1 kW.[50] The result in then grossed up for the summer line loss for capacity of 1.084.[51]

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[48] SCE Experience in 50% cycling Long Island Power Authority based on similar and the Summer Discount Plan Capsule Report dated May 14, 2007.

[49] TP&S experience and research for number of A/C's per customer on Summer Discount Plan

[50] TP&S Experience in 50% cycling Long Island Power Authority based on similar and the Summer Discount Plan Capsule Report dated May 14, 2007.

[51] Market Strategy & Resource Planning - Summer Peak Line Loss.

C. Combustion Turbine Proxy

This section describes SCE's approach in evaluating the economic generation benefits of demand response benefits induced by SCE's dynamic pricing and demand response programs.

This methodology was used in combination with the Commission-assigned estimates of avoided capacity and energy values to analyze the economic benefits of demand reductions. SCE believes the end result is a more accurate and mathematically-sound assessment of the economic value of demand reductions caused by dynamic pricing and demand response programs.

1. Summary of Benefit Calculation Methodology

SCE's approach uses avoided cost principles (marginal energy and capacity) as the value proxy for generation benefits and also incorporates "value adjustments" (both positive and negative) to account for reserve margin benefits, and uncertainties in market forecasts for supply availability and load.

2. Avoided Cost Approach to Value Generation Benefits

Characteristically, demand response programs derive most (~90 percent or more) of their generation-related value from avoided capacity costs rather than avoided energy costs.[52] Limited-event demand response programs or tariffs, such as CPP, are designed to help mitigate peak load requirements for short durations, not unlike a peaking resource. Such limited-event resources provide opportunities to displace higher-cost energy only when triggered. However, dynamic pricing and demand response programs can displace the need for a capacity resource (*i.e.*, combustion turbine) during those periods, which can result in significantly more value than the potential for energy displacement.

Procurement benefits include avoided capacity and avoided energy. Avoided capacity benefits include the value of capacity provided by a particular tariff or load control program. The value of capacity is based on the cost of an avoided combustion turbine ("CT") as

[52] Other potential benefits may exist which are not discussed here, such as O&M savings.

a proxy. The CT proxy value assumed is $71.55/kW in 2006 and escalated each year or $87.78 levelized over the program period. The value of peak reductions from a CPP tariff is adjusted (de-rated) because of the limitation of an assumed number of CPP events per summer season, compared to a combustion turbine, which is available near 100 percent throughout the year. The value of load control programs is also de-rated for similar limitations. The assumption for avoided peak energy value is $102.54/MWh in 2006 and escalated each year for energy avoided during a CPP event. Both the energy and capacity values are assumed to be "at the generator" level.

The Commission has a long-standing policy of using a combustion turbine (CT or peaker) proxy method for estimating the marginal value of capacity and a system marginal energy cost for estimating the marginal value of energy.[53] SCE's view of marginal capacity value is based on the real economic carrying charge methodology[54] of a CT.

D. Time Differentiating Capacity Values

The marginal capacity value of the CT proxy is an annualized value and not differentiated by time. Thus, SCE has "spread" or allocated the annual marginal capacity value using relative loss of load probability (LOLP) values to indicate time differentiated values based on peak period usage.[55] LOLP is a measure of system reliability that indicates the ability (or inability) to deliver energy to the load. The marginal capacity value of the CT proxy is modified to reflect the operational characteristics of demand response programs relative to those of a combustion turbine. These modifications are implemented through the use of two factors (designated by SCE as "A factor" and "B factor") that reflect the operational characteristics of individual demand response programs. The meaning and derivation of these factors is provided below.

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[53] For economic valuation purposes, the value of capacity is never higher than the cost of a CT since any greater capital investment would be justified by lower energy costs. This concept is known as Energy Related Capital Costs ("ERCC").

[54] Also referred to as the rental value or deferral value method. This is consistent with the real economic carrying charge methodology, as has been done in previous GRC filings. SCE's capacity value is assumed to be "at the generator" level and levelized assuming a utility discount rate.

[55] This approach is a standard utility practice and has been used in prior SCE GRC proceedings.

The *A*-factor is determined by simulating an optimal dispatch of a sample demand response program against an LOLP forecast, and calculating the percentage of time the program is able to "displace" LOLP events, subject to the program's dispatch limitations.

The *B*-factor is based on the difference in value between a day-ahead and a day-of call option for power. A CT is essentially a day-of call option with a strike price equal to the variable operating cost of a CT proxy. The CT proxy value should be adjusted downward for demand response programs that are callable on a day-ahead basis. The CPP program, for instance, is a day-ahead call option resource. For a demand response program that can be dispatched on a day-of basis, the *B*-factor equals 1 by default.[56]

The following table summarizes the A and B factor used to derate the marginal capacity value of a CT proxy.

Table B-29
Marginal Capacity Value of CT Proxy

	TOU	CPP	PTR	Smart Thermostat
A Factor	100%	49%	49%	55%
B Factor	100%	95%	95%	96%
Planning Reserve	15%	15%	15%	15%

E. Energy Marginal Costs

The marginal energy cost forecast is based on the methodology applied in the 2006 GRC[57] which is combination of market-derived forward prices and prices from a fundamentals-based production cost simulation. A blended approach of market forwards and fundamentals is a simple and practical method used to account for the latest market view of power prices in the near term, and to account for the declining liquidity of the market view by incorporating a fundamental view in the long term. The energy marginal cost is applied to the megawatts

[56] If the notification time for a day-of CPP program is greater than the time between dispatching a CT and receiving energy, then the value of the B-factor is less than 1.

[57] SCE's Phase II of 2006 GRC Marginal Cost and Sales Forecast Proposals, SCE-2, May 20, 2005.

avoided for dynamic rates and demand response programs to calculate the energy cost avoided in the business case.

Appendix C

Witness Qualifications

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF AHMAD FARUQUI

Q. Please state your name and business address for the record.

A. My name is Ahmad Faruqui. I am a principal with The Brattle Group, located at 353 Sacramento Street, Suite 1140, San Francisco, CA 94111.

Q. Briefly describe your present responsibilities at The Brattle Group.

A. I am the

Q. Briefly describe your educational and professional background.

A. I hold a Ph.D. in economics from the University of California, Davis. I have published more than a hundred articles, papers and books dealing with dynamic pricing, demand response, energy efficiency, demand-side management and load forecasting. I have previously testified before the Commission in the advanced metering application of Pacific Gas and Electric Company.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of Exhibit SCE-4, as identified in the Tables of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF RUSSELL D. GARWACKI

Q. Please state your name and business address for the record.

A. My name is Russell D. Garwacki, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. My current responsibilities include managing the Load Research and Rate Design functions within SCE's Regulatory Policy and Affairs (RP&A) department.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Arts degree in Economics from Whittier College in 1980 and a Master of Arts degree in Economics from Claremont Graduate School in 1983. I have been employed by SCE since 1983. From 1983 to 1993, I worked in the load research area of RP&A, ultimately supervising the group. During that time, I gained an understanding of sample design, cost allocation, and other regulatory policies and procedures. In 1994, I joined the Customer Service Business Unit (CSBU) as the Credit Analysis Manager, working to reduce both write-off and credit operational costs. From 1997 to 1999, I managed the Measurement and Efficiency group, delivering process improvements for CSBU's Field Services, Credit, Payment, and Customer Communication Center functions. From 1999 to 2004, I managed various CSBU activities including Job Skills Training, Internet Delivery, Benchmarking, and various technical support functions. In 2004, I returned to RP&A to assume my current responsibilities.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor those portions of Exhibit SCE-4, as identified in the Tables of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF LAWRENCE M. OLIVA

Q. Please state your name and business address for the record.

A. My name is Lawrence M. Oliva, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am a Director in SCE's Customer Services Business Unit and I lead a group entitled Tariff, Programs and Services. This group is responsible for SCE's Demand Response programs.

Q. Briefly describe your educational and professional background.

A. I earned a Bachelor of Science Degree in Civil Engineering from Southern Methodist University in 1972. Prior to joining SCE as an employee this year, I was a business consultant in the energy industry for over 30 years. I was a principal and director of an international economics consulting firm, Putnam, Hayes and Bartlett, Inc., and a business consulting partner of Arthur Andersen. In past four years, I provided consulting services to SCE in the areas of demand response and advanced metering.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor those portions of Exhibit SCE-4, as identified in the Tables of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

Application No.: 07-07-

Exhibit No.: SCE-5

Witnesses: R. Fisher
L. Letizia

SOUTHERN CALIFORNIA
EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

EDISON SMARTCONNECT™ DEPLOYMENT FUNDING AND COST RECOVERY

Volume 5: Cost Recovery Proposal

Before the

Public Utilities Commission of the State of California

Rosemead, California

July 31, 2007

LAW #1388033

EDISON SMARTCONNECT™ DEPLOYMENT FUNDING AND COST RECOVERY

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EDISON SMARTCONNECT™ DEPLOYMENT FUNDING AND COST RECOVERY

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EDISON SMARTCONNECT™ DEPLOYMENT FUNDING AND COST RECOVERY

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I.

DEPLOYMENT PERIOD COST RECOVERY PROPOSAL

A. Introduction

This exhibit presents SCE's cost recovery proposal for Phase III "Deployment" of Edison SmartConnect™, SCE's advanced metering infrastructure program. SCE requests approval to recover the revenue requirement associated with the costs of Phase III activities described in Exhibit SCE-2. These costs are estimated at approximately $384.2 million in O&M and $1,330.7 million in capital expenditures over the 2008 through 2012 deployment period.[1]

SCE proposes to establish an Edison SmartConnect™ balancing account mechanism to provide for recovery of the deployment period revenue requirement, which will include the recognition of operational benefits in the form of offsets to the Phase III costs.[2] This forecast revenue requirement will be recovered in distribution rates from 2009 through 2012 based on the estimated O&M expenses, depreciation, taxes, and authorized return on rate base amounts as derived from the estimated capital expenditures and the estimated operational benefits as set forth in this application. Beginning in 2009, the forecast Phase III revenue requirement for 2009 and any undercollection in the Base Revenue Requirement Balancing Account (BRRBA) arising from deployment activities in 2007 and 2008 will be reflected in SCE's total distribution rates. However, the proposed operation of the Edison SmartConnect™ balancing account mechanism (*i.e.*, the actual revenue requirement recorded in the Edison SmartConnect™ balancing account will be transferred to the BRRBA each month) will ensure that no more and no less than the reasonable revenue requirement associated with Phase III activities is ultimately collected from customers.

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[1] These amounts include $8 million of capital expenditures and O&M expense that will be incurred in 2007 associated with Phase II activities that did not receive authorization for recovery in the Commission's Phase II Decision No. 07-07-042. In addition, SCE will include in the Edison SmartConnect™ revenue requirement $14.1 million of capital expenditures (plus $0.4 million of AFUDC) approved in D.07-07-042, but not allowed rate base treatment.

[2] As discussed later in this testimony, SCE proposes to flow back all Phase III capital-related benefits outside of the SmartConnect™ balancing account mechanism.

Assuming the Commission approves the scope of activities proposed by SCE and the forecast Phase III costs in this application, SCE's incurred costs that are consistent with the scope and within the cost levels adopted by the Commission should not be subject to an after-the-fact reasonableness review. If actual costs exceed the forecast, or if the scope of activities differs from what the Commission has approved, then SCE would file an application, or other appropriate procedural vehicle, to request approval of the activities and recovery of the additional costs subject to a traditional after-the-fact reasonableness review.

B. Interaction with Other Proceedings

1. Advanced Metering Infrastructure (AMI) Phase I and II (A.05-03-026 and A.06-12-026)

On December 1, 2005, the Commission issued Decision (D.) 05-12-001, "Decision Adopting Settlement For Funding Of Southern California Edison Company's Advanced Integrated Meter Project." The adopted Settlement set forth the scope, timing, and funding for Phase I AMI activities. Pursuant to D.05-12-001, SCE established the Advanced Metering Infrastructure Balancing Account (AMIBA) to provide for the recovery of up to $12 million over an 18-month period for costs related to SCE's Phase I AMI activities.[3] The AMIBA also may be expanded by Commission decisions to include the recorded costs associated with later phases of SCE's AMI project.

SCE initially projected that the Phase I AMI activities would occur over an 18-month time frame, from December 2005 through May 2007. Later, it became apparent that SCE would complete all Phase I AMI activities by year-end 2006. In order to be able to expedite Phase II activities, SCE requested authority in Advice No. 2063-E to establish a memorandum account to track all costs associated with SCE's AMI Phase II pre-deployment activities prior to a Commission decision in that proceeding. The Advanced Metering Infrastructure Memorandum Account for Phase II activities (AMIMA) became effective on December 22, 2006.[4]

[3] The AMIBA was established through SCE Advice Filing No. 1937-E filed on December 6, 2005.

[4] SCE plans to file an advice letter in the third quarter of 2007 requesting the expansion of the AMIMA to record Phase III costs prior to a Commission decision on this Application.

In A.06-12-026, SCE's AMI Phase II application, SCE proposed to modify the current AMIBA to also record, in addition to Phase I AMI costs, up to $63.7 million in costs associated with Phase II AMI pre-deployment activities, from the effective date of a Commission decision in that proceeding through the completion of Phase II. Two sub-accounts within the existing AMIBA would separately record Phase I and Phase II AMI costs. In D.07-07-042, the Commission substantially adopted SCE's ratemaking proposal and set an authorized Phase II expenditure level of $45.220 million. This decision also allowed the continued use of the AMIMA to record costs of any SCE proposed Phase II activities that were not pre-approved by the Commission. SCE expects to record the revenue requirement of approximately $8 million in 2007 to the AMIMA for Phase II activities that were found to be deployment-related activities and thus were not pre-approved for recovery in D.07-07-042. Consistent with the Commission's direction in D.07-07-042 that it would be more appropriate to review Phase II costs that the Commission considers to be deployment-related costs in SCE's deployment application, SCE is requesting cost recovery of this $8 million in this application and has included the amount in the forecast revenue requirements presented in this exhibit.[5]

2. 2009 General Rate Case

SCE expects to file its 2009 GRC application later in 2007.[6] This application is being prepared on a "stand alone" basis; that is, the 2009 GRC application will not reflect the costs or benefits associated with the Edison SmartConnect™ project. All incremental costs and benefits (or decremental costs) from the Edison SmartConnect™ project for the full deployment period of 2008 through 2012 will be addressed in this application so that neither the costs nor benefits of the Edison SmartConnect™ project will be double-counted.

SCE currently anticipates that the financial impacts of the Edison SmartConnect™ project will be incorporated into its 2012 GRC application; however, due to the overlap between the last

[5] In addition, SCE will include in the Edison SmartConnect™ revenue requirement $14.1 million of capital expenditures (plus $0.4 million of AFUDC) approved in D.07-07-042, but not allowed rate base treatment. D.07-07-042 did allow $5.6 million of Phase II costs to be treated as rate base beginning in 2007 and those associated revenue requirements will be recorded into the existing AMIBA account.

[6] SCE's 2009 GRC Notice of Intent was tendered on July 23, 2007.

year of Edison SmartConnect™ deployment of 2012 and the 2012 GRC test year, SCE may need to seek modifications to the SmartConnect™ balancing account mechanism in its 2012 GRC application.

II.

EDISON SMARTCONNECT™ BALANCING ACCOUNT PROPOSAL

SCE proposes the establishment of a new balancing account — the SmartConnect™ Balancing Account (SmartConnect BA) — to record the revenue requirement reflecting all capital and O&M costs and to capture the operational benefits associated with SCE's full deployment of advanced meters effective with a Commission decision in this proceeding. As described in more detail below, each month, SCE will record into the SmartConnect BA:

1. Capital-related revenue requirements (debit), calculated on actual rate base amounts;
2. Actual incremental O&M costs (debit), calculated on recorded expenses; and
3. Calculated operational O&M benefits (credit).[7]

SCE proposes to transfer the balance in the SmartConnect BA on a monthly basis to the distribution sub-account of the BRRBA. In accord with current ratemaking practices, the December 31st balance recorded in the BRRBA is consolidated into rate levels, on, or soon after, January 1st of each subsequent year as part of SCE's annual Energy Resources Recovery Account (ERRA) Forecast and Consolidation proceeding.

As discussed in Chapter III of this Exhibit, beginning in 2009, SCE also requests authority to include in distribution rate levels the forecast Phase III revenue requirements for each year of the deployment period.[8] Any difference between the forecast Phase III revenue requirement included in rate levels and the actual recorded SmartConnect™ revenue requirement based on recorded costs (*i.e.,* over or under-collection) from 2009 through 2012 will be recorded in the BRRBA. This proposed ratemaking will ensure that no more and no less than the reasonable revenue requirement associated with the Edison SmartConnect™ project is ultimately collected from customers.

Appendix B contains the proposed SmartConnect BA preliminary statement.

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[7] As discussed later in this section, SCE proposes to flow back all Phase III capital-related benefits outside of the SmartConnect BA mechanism.

[8] For example, SCE will consolidate an estimated 2009 SmartConnect™ revenue requirement in 2009 distribution rate levels.

A. Costs

SCE is requesting authorization to incur forecast costs of $384.2 million in incremental O&M expenses and $1,330.7 million in capital expenditures, for a total Phase III funding level of $1,714.9 million. Each month, SCE will record its actual capital-related revenue requirement and the actual incremental O&M costs in the SmartConnect BA. The recorded O&M costs will be based on actual recorded incremental O&M expenses associated with the SmartConnect™ activities authorized by the Commission in this proceeding. The capital-related revenue requirement will consist of depreciation, taxes and authorized return based on actual recorded rate base, including plant additions, accumulated depreciation reserve and accumulated deferred taxes, associated with the SmartConnect™ activities authorized by the Commission in this proceeding.

All recorded incremental costs will include provisions for overhead loadings on direct labor dollars, to account for items such as benefits and payroll taxes.[9] However, SCE will not record labor-related pensions and Post-Retirement Benefits Other Than Pensions (PBOPs) costs in the SmartConnect BA, nor incorporate them into the flow-back of benefits, due to the current establishment of separate ratemaking accounts for the recovery of pensions and PBOPs costs.[10] Recovery of all current actual SCE employee pensions and PBOPs costs occur through separate balancing accounts. SCE proposes to also record the pensions and PBOPs costs associated with incremental Phase III SCE employees in these stand-alone balancing accounts, and not in the SmartConnect BA, to prevent double-recovery, and to provide ease of administration and review.[11] Also in SCE's 2006 GRC, the Commission approved full ratepayer funding of SCE's Results Sharing program, but ordered SCE to track in a one-way memorandum account the authorized and recorded Results Sharing costs. Since this memorandum account is one-way (that is, it compares a GRC authorized level to actual recorded and only credits back

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9 Overhead loading factors will be based on actual recorded or, if recorded is unavailable, authorized rates.

10 In its decision in SCE's 2006 GRC (D.06-06-016), the Commission authorized the establishment of a Pension's balancing account and a PBOPs balancing account through 2008. SCE will propose the continuation of these two balancing accounts in its 2009 GRC application.

11 Also, ratepayers will see the benefits of reduced pensions and PBOPs costs (as a result of reductions in SCE's labor force due to Phase III activities) through the operation of the stand-alone pensions and PBOPs balancing accounts.

to ratepayers any over-collection), Results Sharing costs associated with incremental Phase III SCE employees are properly recovered in the Phase III revenue requirements because the costs associated with these incremental employees were not included in the 2006 GRC, nor will they be included in SCE's 2009 GRC.[12] However, the Results Sharing benefits from labor reductions associated with Edison SmartConnect™ will flow through the operation of the one-way Results Sharing memorandum account, and therefore will not be reflected in the Phase III revenue requirements.

B. Benefits

1. Operational O&M Benefits

Exhibit SCE-3 details the benefits (or cost reductions) SCE forecasts for Phase III of the Edison SmartConnect™ project. Since the majority of the operational O&M benefits forecast by SCE are proportional to the number of meters installed and activated, SCE proposes to recognize all of the operational O&M benefits resulting from the Edison SmartConnect™ project monthly, as meters are activated. By crediting forecast O&M benefits as meters are activated, customers are assured of benefits as the project is implemented.[13]

For the Phase III deployment period of 2008 through 2012, the accrual of O&M benefits in proportion to meter activation average $1.3601 per activated meter per month as shown in Table II-1.[14] For Phase III, SCE will calculate the monthly O&M benefits to be recorded in the SmartConnect BA by multiplying the actual number of activated meters by $1.3601.[15]

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[12] SCE will propose the elimination of the Results Sharing memorandum account in its 2009 GRC application. Regardless of the outcome of this proposal in SCE's 2009 GRC Results Sharing costs associated with incremental Phase III SCE employees will be recovered through the operation of the SmartConnect BA through the full deployment period.

[13] As discussed in Exhibit SCE-2, SCE is requesting the ability to utilize project contingency for any unanticipated SmartConnect™ deployment costs, whether the unanticipated costs arise from increases in estimated costs, or from unanticipated delays in realizing benefits from the meter deployment.

[14] As discussed in the previous section, the O&M benefits are net of pensions and PBOPs benefits due to the establishment of separate ratemaking mechanisms for these costs and also net of Results Sharing benefits since these benefits will be returned to ratepayers through the operation of the GRC-authorized Results Sharing memorandum account.

[15] The SmartConnect™ benefits are estimated to begin an average of four months following the physical meter installation: two months to confirm meter-network connectivity, and an average of two months to realize the labor-related benefits. Under the deployment schedule outlined in Exhibit SCE-2, SCE projects a total of nearly 122 million "activated meter-months" between 2008 and 2012.

Table II-1
Development of Average O&M Benefit per Active Meter Month
2008 – 2012

Line No.	Item	Total
1.	O&M Benefits as set forth in SCE-2	$188,382,728
2.	O&M Benefits net of pensions, PBOPs, & Results Sharing	$165,836,646
3.	Total Sum of Active Meter Months	121,929,279
4.	Avg. O&M Benefit per Active Meter Month	$1.3601
	(Line 4 = Line 2 divided by Line 3)	

2. Operational Capital Benefits

Exhibit SCE-2 details the capital benefits SCE forecasts to result from the Edison SmartConnect™ project. As discussed in Exhibit SCE-2, the capital benefits are primarily related to: (1) avoided cost of electro-mechanical meters, (2) deferred projects (load control and price response projects), and (3) computers. All of these capital projects are, or will be, included in the Authorized Distribution Base Revenue Requirement (ADBRR) adopted in SCE's GRCs (2006 GRC for 2008, and 2009 GRC for 2009 – 2011), and the revenue requirement for each project will be credited back to customers based on the actual amounts associated with each and reflected in rates.

Therefore, SCE proposes to recognize all of the capital benefits resulting from the Edison SmartConnect™ project on an annual basis, through reductions to its ADBRR. SCE's current estimate for the capital-related revenue requirement reductions is $0.8 million, $4.9 million and $9.3 million for 2009, 2010 and 2011, respectively. SCE will include the ADBRR reductions based on the specific capital projects as set forth in this application, and included in SCE's GRCs, in annual advice letter filings, filed pursuant to SCE's Post-Test Year Ratemaking Mechanism.[16]

[16] SCE currently expects that all of the Phase III costs and benefits, as adopted in a decision in this proceeding, will be incorporated into its 2012 GRC forecast; and therefore a separate ADBRR reduction for 2012 Phase III capital benefits may not be necessary.

As noted in Exhibit SCE-4, demand response-related benefits (*e.g.* avoided procurement costs) are not included in SCE's net revenue requirements since these benefits are dependent on customer behavior and should not be viewed as utility cost savings unless they materialize in the future.

SCE currently anticipates that it will address the operational benefit savings achieved after 2012 in its 2012 GRC.

C. Reasonableness Review

Assuming the Commission approves the scope of activities proposed by SCE and the forecast Phase III costs in this application, SCE's incurred costs that are consistent with the scope and within the cost levels adopted by the Commission should not be subject to an after-the-fact reasonableness review. If actual costs exceed the forecast, or if the scope of activities differs from what the Commission has approved, then SCE would file an application, or use other appropriate procedural vehicles, to request approval of the activities and recovery of the additional costs through a traditional after-the-fact reasonableness review.

Pursuant to the Commission-adopted process for reviewing other SCE balancing accounts, including the current AMIBA review procedures, SCE proposes that the recorded operation of the SmartConnect BA be reviewed by the Commission in SCE's annual ERRA reasonableness applications. This review of the SmartConnect BA will ensure that all entries to the account are stated correctly and are consistent with Commission decisions. Similar to the adopted Commission review procedures for Phase I and Phase II AMI costs, Commission review procedures for Phase III Edison SmartConnect™ costs should continue to be limited to ensuring that all recorded costs are associated with Phase III activities as defined and within the cost levels adopted by the Commission in this proceeding, in addition to ensuring that benefits are being captured according to the Commission-adopted methodology.

III.

FORECAST OF EDISON SMARTCONNECT™ REVENUE REQUIREMENTS

The Edison SmartConnect™ Phase III 2008 – 2012 revenue requirements include all capital-related costs and incremental O&M expenses, net of forecast operational benefits, needed from customers to recover the cost of the Edison SmartConnect™ project. SCE's forecast Edison SmartConnect™ revenue requirement reflects Phase III funding of $384.2 million in O&M expenses and $1,330.7 million in capital expenditures over the period commencing January 1, 2008 through December 31, 2012.[17] This revenue requirement is incremental to the revenue requirement reflected in either SCE's 2006 GRC or in SCE's 2009 GRC to be filed later in 2007.

The 2008 through 2012 Edison SmartConnect™ revenue requirements are based on the projection of O&M expenses, capital expenditures, and operational benefits (both O&M and capital-related) as shown in Exhibit SCE-2. However, as discussed in the preceding section, due to the current establishment of separate ratemaking accounts for the recovery of pensions, PBOPs and Results Sharing costs, SCE must adjust pensions and PBOPs costs out of the Phase III forecast O&M expenses and capital expenditures, and adjust pensions, PBOPs and Results Sharing benefits out of the Phase III forecast operational benefits, as shown in Exhibit SCE-2, before calculating the Phase III revenue requirements.

Table III-2 below provides, at the aggregate level, the Phase III capital expenditures, incremental O&M expenses, and operational benefits (cost reductions) as set forth in Exhibit SCE-2. Table III-3 below provides, at the aggregate level, the Phase III capital expenditures, incremental O&M expenses, and operational benefits (cost reductions) that are reflected in the Phase III revenue requirements for 2008 through 2012, adjusted for pensions, PBOPs and Results Sharing amounts.

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[17] All costs and revenue requirements presented herein include the $8 million of costs forecast to be recorded to the AMIMA in 2007. In addition, SCE will include in the Edison SmartConnect™ revenue requirement $14.1 million of capital expenditures (plus $0.4 million of AFUDC) approved in D. 07-07-042, but not allowed rate base treatment.

Table III-2
Summary of Edison SmartConnect™ Capital Expenditures, O&M Expenses and Operating Benefits
(millions of nominal dollars)

Line No.	Item	2007	2008	2009	2010	2011	2012	Total
1.	Capital							
2.	Costs	6.7	114.0	332.2	372.2	351.3	154.3	1,330.7
3.	Operational Benefits		(4.7)	(22.2)	(26.0)	(38.3)	(70.4)	(161.6)
4.	Costs – Phase II 1/	14.5						14.5
5.	O&M							
6.	Costs	1.4	37.0	72.9	88.4	96.6	87.9	384.2
7.	Operational Benefits		(1.2)	(8.2)	(29.0)	(60.7)	(89.3)	(188.4)
	1/ Includes $0.4 million AFUDC							

Table III-3
Summary of Edison SmartConnect™ Capital Expenditures O&M Expenses and Operating Benefits, Adjusted for Pensions, PBOPs and Results Sharing
(millions of nominal dollars)

Line No.	Item	2007	2008	2009	2010	2011	2012	Total
1.	Capital							
2.	Costs	21.2	112.4	326.9	366.4	346.1	152.0	1,325.0
3.	Operational Benefits		(4.6)	(22.0)	(25.7)	(37.6)	(69.1)	(159.0)
4.	O&M							
5.	Costs	1.4	36.0	71.1	86.2	94.2	85.7	374.6
6.	Operational Benefits		(0.2)	(4.9)	(28.1)	(54.2)	(78.5)	(165.9)

Based on the capital expenditures, incremental O&M expenses and operating benefits shown above, SCE's forecasted 2008 – 2012 Edison SmartConnect™ revenue requirements were calculated, and are summarized in Table III-4 below. The capital-related revenue requirements include depreciation, taxes and return. The plant-in-service additions to rate base are discussed in Chapter IV of this exhibit and include AFUDC.

Table III-4
Summary of Edison SmartConnect™ Revenue Requirements
(O&M and Capital Costs, net of operating benefits)
Thousands of Dollars

Line No.	Item	2007	2008	2009	2010	2011	2012
1.	**Operating Revenues 1/**	**1,403**	**39,576**	**104,204**	**163,304**	**214,595**	**231,522**
2.	**Operating Expenses:**						
3.	O&M Expense	1,354	36,000	71,149	86,216	94,173	85,725
4.	O&M Benefits	-	(167)	(4,929)	(28,113)	(54,173)	(78,455)
5.	Uncollectible Expense	3	89	234	367	483	521
6.	Franchise Requirements	13	353	931	1,458	1,916	2,067
7.	Depreciation	631	7,659	23,867	44,705	65,586	79,904
8.	Taxes Other than Income	-	10	321	2,120	5,381	8,780
9.	Taxes Based on Income	(921)	(9,751)	(9,600)	8,686	28,040	44,514
10.	Total Operating Expenses	1,080	34,194	81,974	115,439	141,407	143,056
11.	**Net Operating Revenue**	**323**	**5,382**	**22,230**	**47,865**	**73,188**	**88,466**
12.	**Rate Base (Average)**	3,680	61,369	253,481	545,782	834,531	1,008,737
13.	**Rate of Return**	8.77%	8.77%	8.77%	8.77%	8.77%	8.77%

1/ Includes $14.1 million of approved Phase II capital expenditures not allowed rate base treament.

Upon Commission approval of this application, SCE will file an advice letter to implement changes to its preliminary statements and to include in distribution rates, effective January 1, 2009: (1) the forecast Edison SmartConnect™ 2009 revenue requirement of $104.2 million, (2) any undercollection in the BRRBA arising from deployment activities in 2008, (3) 2007 and 2008 recorded amounts in the AMIMA associated with the $8 million of costs that will be incurred in 2007 associated with Phase II activities that did not receive authorization for recovery in D.07-07-042, and (4) 2007 and 2008 recorded amounts in the AMIMA associated with the $14.1 million of capital expenditures (plus $0.4 million of AFUDC) approved in D.07-07-042 but not allowed rate base treatment. The total of these deployment revenue requirements is estimated to be $145.183 million. These revenue changes would be consolidated and made when all other previously authorized revenue changes are reflected in rates, consistent with the practice adopted for SCE's ERRA applications.

SCE will provide revised January 1, 2009 through 2012 SmartConnect™ revenue requirements to the Commission for approval at least 60 days in advance of the January 1 effective dates by Advice Letter.[18] In the annual advice filings, SCE will update the 2009 through 2012 SmartConnect™ revenue requirements to reflect the most recently adopted rate of return on rate base, franchise fees and uncollectible rates, and tax rates. SCE would then consolidate the changes in its distribution rates to reflect these updated SmartConnect™ revenue requirements in conjunction with other rate level changes in its annual August ERRA applications.

[18] SCE currently expects that all of the Phase III costs and benefits, as adopted in a decision in this proceeding, will be incorporated into its 2012 GRC forecast; and therefore a separate rate change for the 2012 Phase III revenue requirement may not be necessary.

IV.

EDISON SMARTCONNECT™ PLANT, DEPRECIATION AND RATE BASE FORECAST

This Chapter summarizes SCE's expected average Plant-In-Service[19] balances for the estimated years 2007 through 2012 for Edison SmartConnect™ deployment capital costs. This Chapter also summarizes SCE's plant work order closing process and its approach to converting capital expenditures to Plant-In-Service. This testimony, combined with the other testimony on SCE's capital expenditures in Edison SmartConnect™ filing, demonstrates that SCE's Plant-In-Service estimates are reasonable and should be approved for recovery from ratepayers.

A. Electric Plant-In-Service

Table IV-5 shows Plant-In-Service on a weighted average basis for the 2007-2012 period.[20] The Plant Balances are summarized by FERC class of plant.

Table IV-5
Summary of Electric Plant
Average Balances
(Systems Basis, Nominal $000)

Line No.	Class of Plant	2007	2008	2009	2010	2011	2012
1.	Telecommunications	-	10,667	39,554	79,843	121,528	146,146
2.	Computers	969	5,933	12,023	16,587	21,678	25,289
3.	Meters	-	6,958	120,189	361,319	632,645	838,826
4.	Cap Soft 7yr	3,059	37,020	83,943	111,455	126,559	132,200
5.	General Buildings	-	4,993	12,622	15,474	15,707	15,868
6.	Total	4,029	65,571	268,332	584,678	918,117	1,158,329

[19] Electric Plant-In-Service includes FERC Account 101 (Electric Plant-in-Service), and FERC Account 106 (Completed Construction Not Classified).

[20] For purposes of this filing, SCE calculated a simple average of Plant-In-Service (*i.e.,* the sum of the plant balance at the beginning-of-year and end-of-year divided by two).

1. Forecasting Capital Additions

All estimated capital additions shown are derived from forecast capital expenditures included in Exhibit SCE-2. To determine the plant balance included in Rate Base, it is necessary to first convert the capital expenditures into plant additions.

a) Direct Expenditures

Exhibit SCE-2 contains estimated 2008 through 2012 direct capital expenditures. Direct expenditures include costs for materials, direct labor, costs for removal, and divisional overheads.

b) Costs For Removal

Costs for removal, also called Cost of Removal ("COR"), are the costs for removal and disposal of a plant asset. The costs SCE expects to incur for the removal of assets are included in capital expenditures since it represents a cash flow associated with capital. Costs for removal are not capitalized to Plant-In-Service but are instead recorded as a debit (decrease) to SCE's accumulated depreciation reserve.

The COR embedded in the capital expenditures is not the same as the COR recovered through depreciation accrual.[21] The former represents the *cash* outlay that will be made during 2007-2012 for the assets expected to retire in those years; the latter is the *accrual* for the future removal of all existing assets. In accounting terms, the accrual for COR credits (increases) accumulated depreciation reserve to make a provision for *future* removal cost. The cash outlay, on the other hand, debits (decreases) the accumulated depreciation reserve. That is, the cash outlay offsets the previously accrued provision for removal cost.

SCE will incur removal costs associated with the replacement of the existing meters. The 2007 and 2008 depreciation accrual for meter removal cost is included in SCE's authorized depreciation rates[22] and depreciation accrual for years 2009 and forward is addressed in SCE's 2009

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[21] The COR accounted for in depreciation accrual is embedded in the current authorized depreciation rates for SCE's existing meters. Recovery of the costs associated with removal of existing meters is addressed in SCE's 2009 GRC NOI tendered July 23, 2007.

[22] D.06-05-016.

GRC Notice of Intent tendered July 23, 2007.[23] The cash outlay for removal costs, however, has an incremental rate base effect (by lowering accumulated depreciation) that is reflected in this filing. The balance forecast for removal costs are shown in Table IV-6.

Table IV-6
Cost of Removal Reduction to Accumulated Depreciation
Average Balance
(System Basis, Nominal $000)

Line No.	Class of Plant	2007	2008	2009	2010	2011	2012
1.	Meters	-	925	10,570	30,261	52,465	69,891

c) Corporate Overheads

Capitalized Corporate Overheads are similar to capitalized divisional overheads, in that they support all SCE capital projects, rather than a particular project. Corporate Overhead costs are charged monthly to CWIP through work order cost accounts. Capitalized corporate overheads typically consist of costs for Corporate Administrative & General (A&G),[24] Pensions & Benefits (P&B), Payroll Taxes, Property Taxes, and Injuries & Damages. Only capitalized overheads associated with the incremental capitalized P&B and results sharing for Edison SmartConnect™ deployment have been included in this filing.

d) Allowance for Funds Used During Construction (AFUDC)

Accruing for AFUDC is the generally accepted regulatory accounting procedure to capitalize the cost of debt and equity funds used to finance capital additions during construction.[25] The annual estimated AFUDC rates are developed from estimates of costs of debt and equity required to fund the forecasted construction estimates. The estimated amount of AFUDC to include in the estimated plant additions is determined by applying the estimated AFUDC rates to the accumulated costs, similar to a compounding monthly interest calculation.

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[23] SCE's 2009 NOI, SCE-11, Volume 3.

[24] Beginning in 2009, SCE has proposed in its 2009 GRC NOI, to include results sharing in corporate A&G.

[25] FERC 18 Code of Federal Regulation, Electric Plant Instruction 3 - Components of Construction Cost, sub-paragraph 17 - Allowance for Funds Used During Construction.

e) The Date Construction Costs Are Estimated to Close to Plant-In-Service

SCE's plant addition forecast does not apply construction costs as plant additions until the date the assets are estimated to be in service.[26] Correctly forecasting the *level* of plant additions to close each year is contingent upon when construction costs are expected to be in service. We use planned deployment specific information to estimate when the Edison SmartConnect™ capital costs should be included in Plant-In-Service.

The capital spending for Edison SmartConnect™ deployment is separated into two closing categories, determined by the type of construction work each budget item represents and how the work orders will most likely be processed.

(1) Specifics

Specific type budget items represent a single construction effort in which all of the estimated costs will close to Plant-In-Service when the asset is reported as in service. An in-service date is used to estimate the year the total accumulated construction costs will close to Plant-In-Service.

(2) Blankets

Blankets represent capital expenditures for assets that are closed to Plant-In-Service upon purchase. Meters are an example of blanket capital. Charges to blanket work orders are recorded to Plant-In-Service one month after the money is spent. For example, expenditures forecast in January will close to Plant-In-Service in February.

2. Forecasting Retirements

SCE does not expect any material retirements of the new assets as part of the Edison SmartConnect™ deployment to occur in the period 2007 through 2012. The retirement of existing assets as a result of the Edison SmartConnect™ is addressed in SCE's 2009 General Rate Case. Cost of

[26] SCE adheres to the Code of Federal Regulations 18 Part 101 (FERC Uniform System of Accounts) when determining the transition of costs from General Ledger account 107 (Construction Work in Progress) to General Ledger accounts 101 (Electric plant in service) and 106 (Completed construction not classified).

removal incurred as a result of the Edison SmartConnect™ deployment is addressed in "Costs for Removal" section of this Chapter.

B. Forecast Depreciation Expense and Accumulated Depreciation

The costs of the fixed capital investment are allocated over the life of the capital investment. Depreciation expense is the means by which those capital investment costs are allocated.

1. Annual Depreciation Expense

The annual depreciation expense for forecast years 2007 through 2012 is presented in Table IV-7.

Table IV-7
Depreciation And Amortization Expense
(System Basis, Nominal $000)

Line No.	Class of Plant	2007	2008	2009	2010	2011	2012
1.	Telecommunications	-	711	2,637	5,323	8,102	9,743
2.	Computers	194	1,187	2,405	3,317	4,336	4,864
3.	Meters	-	383	6,610	19,873	34,795	46,135
4.	Cap Soft 7yr	437	5,289	11,992	15,922	18,080	18,886
5.	General Buildings	-	90	223	270	273	276
6.	Total	631	7,659	23,867	44,705	65,586	79,904

2. Accumulated Depreciation

The average accumulated depreciation balances for forecast years 2007 through 2012 are presented in Table IV-8.[27]

[27] For purposes of this filing, SCE calculated a simple average of Accumulated Depreciation balances (*i.e.,* the sum of the plan balance at the beginning-of-year and end-of-year divided by two).

Table IV-8
Average Accumulated Depreciation Reserve And Amortization
(System Basis, Nominal $000)

Line No.	Class of Plant	2007	2008	2009	2010	2011	2012
1.	Telecommunications	-	356	2,030	6,009	12,722	21,644
2.	Computers	97	787	2,583	5,444	9,270	13,870
3.	Meters	-	(733)	(6,882)	(13,331)	(8,202)	14,837
4.	Cap Soft 7yr	219	3,081	11,722	25,679	42,680	61,162
5.	General Buildings	-	45	202	449	720	995
6.	Total	315	3,536	9,654	24,249	57,190	112,509

3. Depreciation Calculation

The depreciation rates used to forecast annual depreciation expense are determined consistent with this Commission's prescribed STANDARD PRACTICE U-4, DETERMINATION OF STRAIGHT-LINE REMAINING LIFE DEPRECIATION ACCRUALS. As the full title of the STANDARD PRACTICE U-4 indicates, the Commission has specified certain aspects of the depreciation procedure – namely the straight-line *method* and the remaining life *technique*.

Table IV-9 below shows annual depreciation rates proposed for years 2007-2012 for Plant-In-Service estimated in this filing:

Table IV-9
Annual Depreciation Rates by Class of Plant

Line No.	Class of Plant	2007-2008	2009-2012
1.	Telecommunications	6.67%	6.67%
2.	Computers	20.00%	20.00%
3.	Meters	5.50%	5.50%
4.	Cap Soft 7yr	14.30%	14.30%
5.	General Buildings	1.81%	1.62%

For telecommunication (15-year telecommunication equipment in FERC plant account 397) and computers (portions of FERC plant account 391), SCE proposes no change from rates authorized in SCE's 2006 GRC.[28] For General Buildings (FERC plant account 390) SCE's depreciation rate authorized in SCE's 2006 GRC for years 2007 and 2008,[29] and SCE's proposed depreciation rate in its 2009 GRC NOI for years 2009 through 2012. For capitalized software, SCE had three life groups previously: 5-, 10-, and 15-years. SCE has added a 7-year group for recent investments in capitalized software. For the new Edison SmartConnect™ meters, SCE proposes a new depreciation rate based a change to 20-year average service life and authorized levels of future net salvage, which is discussed in the following sections.[30]

a) Average Service Life of Edison SmartConnect™ Meters

In SCE's 2006 GRC, the Commission authorized SCE's proposed R2 retirement dispersion and 30-year average service life for meters. SCE proposed continued use of the R2 retirement dispersion, but proposes a new average service life of 20 years, consistent with the life of the new Edison SmartConnect™ meters.[31]

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[28] D.06-05-016.

[29] *Id.*

[30] The 5.5% depreciation rate is the quotient of 100% less net salvage of -10% and 20 years. 5.5% = [100% - (-10%)]/20.

[31] *See* Exhibit SCE-1.

b) Future Net Salvage of Edison SmartConnect™ Meters

Net Salvage is equal to the gross salvage less the removal cost associated with a plant retirement. For example, when a meter is placed into service the company applies an estimate of the future salvage value (*e.g.*, scrap value) expected at the end of its service life. This salvage value is netted against the cost to remove the meter. Net salvage can either be expressed as a dollar amount or as percent of the original plant cost. In either case, STANDARD PRACTICE U-4 includes net salvage in the determination of depreciation expense.[32] In recent years removal cost has generally exceeded the gross salvage resulting in a negative net salvage. Because the amount to be depreciated is the difference between original cost and salvage value, a negative net salvage value will increased depreciation rates. DEPRECIATION SYSTEMS instructs:

> The original cost less net salvage is called the *depreciable base*. It represents the capital consumed during the life of the unit and the amount to be recovered through depreciation. If the net salvage is positive, then the capital consumed is less than the original cost. If the net salvage is negative, the capital is greater than the original cost.[33]

NARUC states that, "most regulatory commissions have required that both gross salvage and cost of removal be reflected in depreciation rates."[34] Although a few jurisdictions have chosen to ignore them (apparently in an attempt to lower revenue requirements by shifting net salvage cost recovery to future periods), NARUC points out that there are sound principles for the requirement "that the estimated [gross salvage and] cost of removal of plant be recovered over its life."[35] Those principles include "the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, no more, no less."[36]

[32] STANDARD PRACTICE U-4, pp. 8, 12.

[33] DEPRECIATION SYSTEMS, W. C. Fitch and Frank K. Wolf, 1994, p. 51.

[34] PUBLIC UTILITY DEPRECIATION PRACTICES, NARUC, 1996, p. 157.

[35] *Id.*

[36] *Id.*

The current authorized future net salvage for meters is -10% (0% gross salvage less 10% cost of removal). SCE proposes retaining the current authorized net salvage for meters. Removal cost for meters is largely attributable to labor, a factor that is not expected to be different from existing meters. Additionally, the future gross salvage value of the new meters is not expected to be materially different from SCE's existing meters.

C. Rate Base

Rate Base is computed on an original cost basis and is presented as an average of year-end balances to reflect the changes in investment levels throughout the year. The average for this filing is the sum of the beginning-of-year and end-of-year balances divided by 2. The average accumulated deferred tax rate base component has been computed in accordance with the pro-ration requirements of the Federal tax law.

Fixed capital forecasts are based on the forecast capital spending required for Edison SmartConnect™ deployment. Table IV-10 below shows annual average rate base.

Table IV-10
Summary Edison SmartConnect™ Rate Base
(System Basis, Nominal $000)

Line No.	Description	2007	2008	2009	2010	2011	2012
1.	Fixed Capital	4,029	65,571	268,332	584,678	918,117	1,158,329
2.	Less: Accumulated Depreciation and Amortization	315	3,536	9,654	24,249	57,190	112,509
3.	Less: Deferred Taxes	34	666	5,197	14,647	26,396	37,083
5.	Total Rate Base	3,679	61,369	253,481	545,782	834,531	1,008,737

1. Plant-In-Service and Intangibles

Electric Plant-In-Service consists of balance sheet Accounts 101-*Electric Plant-In-Service*, and 106–*Completed Construction not Classified*. This information is drawn from Table II-1 in this Chapter.

2. Accumulated Depreciation and Amortization

Accumulated Depreciation is the total depreciation accrual charges adjusted for cost of removal. The accumulated depreciation used in the Rate Base calculation is listed by class of plant in Table IV-8 of this Chapter.

3. Accumulated Deferred Taxes–Plant

Accumulated Deferred Taxes – Plant reflects a reserve component based on previously adopted Commission decisions and tax law provisions applicable to the Economic Recovery Tax Act of 1981 and incorporating the tax law modifications imposed by the Tax Reform Act of 1986. The Internal Revenue Code requires that deferred taxes be incorporated into rate base computations if the Company wishes to avail itself of the favorable accelerated tax depreciation methods provided by the Modified Accelerated Cost Recovery System (MACRS) tax depreciation rules. The computation of deferred taxes included in rate base has been performed in accordance with the Internal Revenue Code rules applicable to public utilities, including the use of the pro-ration method.[37]

[37] Currently, for Federal tax deprecation purposes, Edison SmartConnect™ meters are classified as distribution property eligible for 20-year MACRS depreciation. There is legislation before the U.S. Congress which proposed to change the life of new meters with certain attributes to a 5-year MACRS property. If this favorable legislation is enacted, and the Edison SmartConnect™ meters qualify for this accelerated depreciation treatment, the benefits will be included in the computation of rate base and tax expense and reflected in the balancing account.

V.

SUMMARY OF COST RECOVERY PROPOSAL

In conclusion, SCE respectfully requests that the Commission:

(1) Authorize SCE to establish the Edison SmartConnect™ Balancing Account (SmartConnect BA) to provide for the recovery of Phase III recorded revenue requirements, which include recorded incremental costs and recognition of forecast operational O&M benefits, effective upon a Commission decision on this application;

(2) Authorize SCE to reduce its Authorized Distribution Base Revenue Requirement (ADBRR), on an annual basis, in order to recognize the Phase III capital benefits related to specific projects as set forth, and as adopted, in this proceeding, through the effective date of SCE's 2012 GRC Decision;

(3) Authorize SCE to transfer the balance in the SmartConnect BA, each month, to the Base Revenue Requirement Balancing Account (BRRBA) to enable recovery, through distribution rate levels, of the actual Edison SmartConnect™-related revenue requirements for Phase III activities beginning on the effective date of a decision in this proceeding and continuing through the effective date of SCE's 2012 GRC Decision;

(4) Authorize SCE to transfer from the AMIMA to the BRRBA 2007 and 2008 recorded revenue requirements associated with costs that will be incurred in 2007 associated with Phase II activities that did not receive authorization for recovery in D.07-07-042 and 2007 and 2008 recorded revenue requirements associated with the $14.1 million of capital expenditures (plus $0.4 million of AFUDC) approved in D.07-07.042 but not allowed rate base treatment;

(5) Authorize rate recovery, through distribution rate levels, of SCE's forecast Edison SmartConnect™ revenue requirements for Phase III activities effective upon a Commission decision on this application and continuing through the effective date of SCE's 2012 GRC Decision; and

(6) Limit reasonableness review of the SmartConnect BA to ensure all recorded costs are associated with Phase III activities as defined and adopted by the Commission in this proceeding.

Appendix A

Witness Qualifications

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF RICHARD FISHER

Q. Please state your name and business address for the record.

A. My name is Richard Fisher, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the manager of the Rate Base and Depreciation group in the Capital Recovery Division, responsible for recorded depreciation, nuclear decommissioning, and portions of rate base.

Q. Briefly describe your educational and professional background.

A. I have a Bachelor of Science Degree in Business Administration, with an emphasis in Finance, Real Estate, and Law, from California State Polytechnic University, Pomona. I am currently completing course work towards a Masters degree in Business Administration at the University of Southern California and will be completed by June 2008. I am a member of the Society of Depreciation Professionals and have been qualified as a Certified Depreciation Professional.

Since my employment with Southern California Edison in 1999 I have been with the Capital Recovery Division of the Controllers Department. My responsibilities have included functions involving depreciation and nuclear decommissioning accounting, depreciation studies, and the development of forecasting models for plant additions, rate base, and depreciation expense in direct support of the Company's regulatory proceedings. I have previously testified before the California Public Utilities Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor those portions of Exhibit SCE-5, as identified in the Tables of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF LINDA R. LETIZIA

Q. Please state your name and business address for the record.

A. My name is Linda R. Letizia, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company (SCE).

A. I am a Manager of Special Regulatory Projects in the Regulatory Policy and Affairs Department, and have responsibility for the management, development, and presentation of various ratemaking showings before the California Public Utilities Commission.

Q. Briefly describe your educational and professional background.

A. I graduated from the University of California at Davis in 1980 with a Bachelor of Science degree in Mathematics. I have been employed by Southern California Edison Company since 1984. Since joining Edison, I have held various positions in the Regulatory Policy and Affairs Department. My responsibilities have included revenue allocation and rate design, the preparation of pricing studies and analyses, and the development of revenue requirements and ratemaking proposals for numerous regulatory proceedings before the California Public Utilities Commission. I have also been employed in the Capital Recovery Section and Corporate Budgets Section of the Controller's Department. I have previously testified before the California Public Utilities Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor those portions of Exhibit SCE-5, as identified in the Tables of Contents herein.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

Appendix B

Proposed SmartConnect BA Preliminary Statement

PROPOSED PRELIMINARY STATEMENT

Edison SmartConnect Balancing Account (SmartConnect™ BA)

I. Purpose

The purpose of the Edison SmartConnect Balancing Account (SmartConnect™ BA) is to record all costs incurred by SCE, up to $X.XXX billion, and to capture the operational benefits as set forth herein, associated with the Phase III Edison SmartConnect™ advanced metering deployment activities as authorized by the Commission in Decision No. 08-XX-XXX through the effective date of SCE's 2012 GRC decision.

II. Operation of the SmartConnect™ BA

Entries to the SmartConnect™ BA shall be made monthly as follows:

(1) Recorded, incremental SCE Operation and Maintenance (O&M) expenses associated with Phase III activities (debit); plus

(2) Capital-related revenue requirements (depreciation, income and property taxes and return on rate base), calculated on actual rate base amounts associated with Phase III activities (debit); plus

(3) Operational benefits calculated as set forth below (credit).

The authorized Phase III revenue requirements will be collected in rates as one component of total distribution rates. The SmartConnect™ BA balance shall be transferred on a monthly basis to the distribution sub-account of the Base Revenue Requirement Balancing Account (BRRBA). Interest expense shall not be recorded in the SmartConnect™ BA since the monthly activity is transferred to the BRRBA.

III. SmartConnect™ BA Costs

Phase III incremental O&M and capital-related costs shall be related to one of the following areas:

1. Acquisition of meters and communication network equipment;
2. Installation of meters and communication network equipment;
3. Implementation and operation of new back office systems;

4. Customer tariffs, programs and services;
5. Customer Service Operations;
6. Overall program management;
7. Contingencies for mass meter deployment; and
8. Any other activities as related to Phase III as authorized by the Commission in D. 08-XX-XXX.

All recorded, incremental costs shall include provisions for overhead loadings on direct labor dollars to account for items such as benefits, results sharing and payroll taxes. The overhead loading factors shall be based on actual recorded, or if recorded is unavailable, authorized GRC rates. However, SCE shall not record Pensions and Post-Retirement Other Than Pensions (PBOPs) costs into the SmartConnect™ BA due to the existence of other balancing accounts authorized for Pensions and PBOPs recovery.

IV. SmartConnect™ BA Benefit Calculation

Each month SCE shall calculate the amount of operational O&M benefits to be credited to the SmartConnect™ BA as follows:

1. Recorded total sum of Active Meter Months;
2. Multiplied by $1.3601 of average O&M benefits per active meter month as authorized in D. 08-XX-XXX.

All capital-related benefits shall be returned to customers through the operation of the BRRBA as authorized in D.08-XX-XXX.

V. Review Procedures

The recorded operation of the SmartConnect™ BA for the Record Period (or previous calendar year 12-month period) shall be reviewed by the Commission in SCE's annual April ERRA application to ensure that the entries made in the SmartConnect™ BA are stated correctly and were incurred for Phase III activities as authorized by the Commission.

SCE shall provide a monthly report showing the activity in the SmartConnect™ BA to the Energy Division within 30 days of the end of each calendar month.