BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Approval of its Smart Grid Deployment Plan	A. 11-07-___ (Filed July 1, 2011)

APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY (U-338-E) FOR APPROVAL OF ITS SMART GRID DEPLOYMENT PLAN

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Dated: **July 1, 2011**

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I. INTRODUCTION

Southern California Edison Company (SCE) respectfully files this Application seeking approval of its Smart Grid Deployment Plan. SCE submits this Application in accordance with Senate Bill (SB) 17 (Padilla), Chapter 327, Statutes of 2009, as codified at California Public Utilities Code § 8360-69. In June 2010, the California Public Utilities Commission (Commission) issued Decision (D.) 10-06-047 (Decision),[1] which established the requirements that each of the investor-owned utilities (IOUs) must address in seeking approval of their Deployment Plans.

II. BACKGROUND

SB 17 established as state policy the modernization of its "electrical transmission and distribution system to maintain safe, reliable, efficient, and secure electrical service, with infrastructure that can meet future growth in demand and achieve." It mandates:

[1] Decision Adopting Requirements for Smart Grid Deployment Plans Pursuant to Senate Bill 17 (Padilla), Chapter 327, Statutes of 2009, issued June 24, 2010.

(a) Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid.

(b) Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security.

(c) Deployment and integration of cost-effective distributed resources and generation, including renewable resources.

(d) Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources.

(e) Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation.

(f) Integration of cost-effective smart appliances and consumer devices.

(g) Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning.

(h) Provide consumers with timely information and control options.

(i) Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.

(j) Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

SB 17 also requires each of California's IOUs, by July 1, 2011, to develop and submit for approval by the Commission a Smart Grid Deployment Plan (Deployment Plan). The Decision, as noted, established the requirements that each of the IOUs must address in seeking approval of their Deployment Plans. The Decision requires the IOUs to follow an eight-element format in their Deployment Plans, and further sets out detailed requirements that IOUs must meet in

presenting each of these elements.[2] The eight elements identified by the Decision are the following:

1. Smart Grid Vision Statement;
2. Deployment Baseline;
3. Smart Grid Strategy;
4. Grid Security and Cyber Security Strategy;
5. Smart Grid Roadmap;
6. Cost Estimates;
7. Benefits Estimates; and
8. Metrics.[3]

III. SUMMARY OF SCE'S DEPLOYMENT PLAN

In compliance with the Decision, SCE submits the attached Deployment Plan for Commission approval. SCE's Deployment Plan addresses each of the requirements identified in the Decision. At the same time, SCE's Plan provides a roadmap that demonstrates how the deployment of smart grid technologies will help enable the goals embodied in SB 17 and other important state policy objectives. SCE therefore respectfully requests that the Commission approve SCE's Deployment Plan.

SCE is investing in a smarter electric grid to meet California's ambitious energy policy goals, take advantage of technological innovations, and engage its customers as partners in both of these pursuits. To meet these objectives, SCE will invest, over time, in advanced energy and information technology that will enable a broad range of smart grid capabilities aimed at delivering a cleaner energy future, a more informed customer, and a more reliable electric system.

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2 Id. at 138-145.

3 D. 10-06-047, Ordering Paragraph No. 2.

SCE's Deployment Plan describes the steps SCE will take to evaluate and deploy these technologies in the eight-element format established by the Decision. It is organized as follows:

1. The Vision chapter identifies the key policy and value drivers that shape SCE's plans for smart grid deployments. It also describes the roles and the ways of achieving a smart market, smart customers, and a smart utility in delivering a smart grid system.

2. The Strategy chapter presents SCE's strategy for deploying a smart grid in a way that aligns with SB 17, meets relevant policy goals, and achieves maximum value for customers.

3. The Deployment Baseline and Smart Grid Roadmap chapter combines two of the Decision's elements. It first provides a snapshot of SCE's current deployments of smart grid technologies. The chapter then describes SCE's specific plans to deploy smart grid technologies through the year 2020 based on guidelines outlined in the Strategy chapter.

4. The Cost Estimates and Benefits Estimates chapters that follow present descriptions and estimates of the costs and benefits of the deployments described in the Deployment Baseline and Smart Grid Roadmap chapter.

5. The Grid Security and Cyber Security Strategy chapter presents SCE's approach to evaluating, preventing, and addressing security threats that it expects to emerge as it deploys smart grid technologies.

6. The Metrics chapter reports values (as of December 31, 2010) of the consensus metrics that were identified in the Report on Consensus and Non-Consensus Smart Grid Metrics prepared by the IOUs in consultation with the Environmental Defense Fund.

IV. PURPOSE AND REVIEW OF THE DEPLOYMENT PLAN

Consistent with the Commission's guidance in the Decision,[4] the presentation of projects in SCE's Deployment Plan should be read as provisional guidance about the smart grid investments that SCE is considering over the next ten years. SCE's understanding of the technologies described in the Deployment Plan, as well as its estimates and characterizations of costs and benefits of those technologies, are likely to change in the future. As such, the Deployment Plan must be viewed by the Commission, SCE, and other stakeholders as a living document whose assumptions and conclusions will necessarily have to be modified and updated over time.

Also consistent with guidance in the Decision, the Deployment Plan should not be viewed as a request for approval of any of the projects described therein.[5] During the period covered by the Deployment Plan, SCE will propose specific smart grid investments and projects in its General Rate Cases or special applications as appropriate. Approval of those investments and proposals will be decided in those proceedings. By contrast, approval of the Deployment Plan should be based on the extent to which it addresses the requirements set forth in the Decision.

SCE's Deployment Plan meets the requirements of the Decision. It sets out a comprehensive and forward-looking plan for bringing the benefits of the smart grid to SCE's customers. Accordingly, SCE respectfully requests that the Commission approve its Deployment Plan.

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[4] See Decision, at p. 22: "It would be wiser to view the Smart Grid Deployment Plan as a policy guide for utility investment, not as a determination that certain investments are reasonable."

[5] Ordering Paragraph No. 14 of the Decision states that: "Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company each shall seek approval of Smart Grid investments either through an application and/or through General Rate Cases."

V. PROCEDURAL REQUIREMENTS

A. Statutory and Procedural Authority

SCE's Application complies with the Commission's Rules of Practice and Procedure, Rules 1.5 through 1.11 and 1.13, which specify the procedures for, among other things, filing documents. In addition, this request complies with Rules 2.1 and 2.2.

Rule 2.1 requires that all applications: (1) clearly and concisely state authority or relief sought; (2) cite the statutory or other authority under which that relief is sought; and (3) be verified by the applicant. Rule 2.1 sets forth further requirements that are addressed separately below.

The relief being sought is summarized in Section III (Summary of SCE's Deployment Plan) and is described in detail in the Deployment Plan accompanying this Application.

The statutory and other authority for this request includes, but are not limited to, SB 17, codified in California Public Utilities Code §§ 8360-8369, D. 10-06-047, the California Public Utilities Code, the Commission's Rules of Practice and Procedure, and prior decisions, orders, and resolutions of this Commission.

SCE's Application has been verified by an SCE officer as provided in Rules 1.11 and 2.1.

B. Legal Name and Correspondence – Rules 2.1(a) and 2.1(b)

SCE 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 on this matter are Kris G. Vyas and Janet S. Combs. Correspondence or communications regarding this Application should be addressed to:

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C. Categorization, Issues and Schedule – Rule 2.1 (c)

Rule 2.1(c) requires that applications shall state "[t]he proposed category for the proceeding, the need for hearing, the issues to be considered, and a proposed schedule." These requirements are discussed below.

1. Proposed Categorization

SCE proposes to characterize this proceeding as "quasi-legislative" as defined in the Commission's Rules of Practice and Procedure, Rule 1.3(d) and Public Utilities Code § 1701.1(c)(1).

2. Proposed Schedule and Hearings for Resolution of Issues

Consistent with prior treatment of smart grid subject matter in R.08-12-009, SCE recommends that the Commission use workshops as a mechanism for seeking public comment and input on the Deployments Plans submitted by the IOUs. Workshops offer an opportunity to engage in iterative discussions that accommodate the complicated and nuanced natured of smart grid issues. SCE proposes the following schedule:

Action	**Date**
Application Filed	July 1, 2011
Responses/Protests	August 1, 2011
Reply to Responses/Protests	August 15, 2011
Workshops	September – October 2011
Opening Briefs	November 14, 2011
Reply Briefs	November 21, 2011
Proposed Decision	February 15, 2012
Comments	March 6, 2012
Reply Comments	March 16, 2012
Commission Decision Adopted	Late March, 2012

3. Issues to be Considered

The issues to be considered in this Application concern the approval of SCE's proposed Smart Grid Deployment Plan, as set forth herein and in SCE's Smart Grid Deployment Plan, preliminarily marked as Exhibit SCE-1.

D. Organization and Qualification to Transact Business – Rule 2.2

A copy of SCE's Certificate of Restated Articles of Incorporation, effective on March 2, 2006, and as 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 incorporated herein by reference pursuant to Rule 2.2 of the Commission's Rules of Practice and Procedure.

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.

VI. CONCLUSION

SCE respectfully requests that the Commission approve its Smart Grid Deployment Plan, and intends that the approved Plan help guide SCE's future investments as we seek to modernize the power grid on behalf of our ratepayers.

Respectfully submitted,

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JANET S. COMBS

/s/ KRIS G. VYAS
By: Kris G. Vyas

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July 1, 2011

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 **1st day of July, 2011**, at Rosemead, California.

/s/ DAVID L. MEAD

David L. Mead
Senior Vice President
SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770

Exhibit 1

SCE SMART GRID DEPLOYMENT PLAN

SOUTHERN CALIFORNIA EDISON®

An EDISON INTERNATIONAL® Company

EDISON INTERNATIONAL Celebrating 125 Years 1886-2011

Southern California Edison

Smart Grid Deployment Plan

July 1, 2011

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I. Executive Summary

In October 2009, Governor Schwarzenegger signed Senate Bill (SB) 17, California's landmark smart grid legislation, into law. That legislation established as state policy the modernization of California's "electrical transmission and distribution system to maintain safe, reliable, efficient, and secure electrical service, with infrastructure that can meet future growth in demand and achieve"[1] a set of goals aimed at a cleaner energy future, energy efficiency and more engaged customers. SB 17 also required the California Public Utilities Commission (CPUC, or Commission), the California Energy Commission (CEC) and the California Independent System Operator (CAISO) to work with the state's electric utilities to provide a roadmap to guide California's progress towards SB 17's goals. This Smart Grid Deployment Plan (Deployment Plan) represents Southern California Edison's (SCE's) initial contribution to that effort.

In compliance with the Commission's Decision Adopting Requirements For Smart Grid Deployment Plans Pursuant to Senate Bill 17 (Padilla), Chapter 327, Statues of 2009 (Decision 10-06-047), SCE is submitting this Deployment Plan for Commission approval. SCE's Deployment Plan represents SCE's effort to meet the requirements of Decision (D.) 10-06-047 and provide a comprehensive description of its plans to deploy smart grid technologies. This narrative should prove instructive for a variety of stakeholders, including the Commission, legislators, consumers, consumer advocates and other interests groups, in their efforts to understand the value and promise of smart grid technologies for California's and the Nation's energy future.

1. SCE's Smart Grid Will Enable Policy Goals, Deliver Value and Engage Customers

SCE is investing in a smarter electric grid to enable California's ambitious energy policy goals, take advantage of technological innovations and engage its customers as partners in both of these pursuits.

California's nation-leading push towards greenhouse gas reduction, renewable power and electric transportation will change the way electric utilities serve California's power needs. From a supply standpoint, the physical properties of renewable power create operational challenges that require an upgrade of the existing power grid. From a demand perspective, self-generation, electric vehicle charging and demand-side management will cause customer behavior to be more dynamic than it has ever been. The convergence of these factors will force SCE and the state's other utilities to build a more robust, flexible and resilient electric grid.

Concurrent with the implementation of California's policy agenda, advances in energy and information technology will provide SCE with new tools to address policy-related challenges and improve operations.

1 Codified at Pub. Util. Code § 8360.

Real-time information about system conditions, automated control of power system equipment and enhanced communications with customers will all help SCE deliver safe and reliable service as California moves toward a cleaner energy future. At the same time, this information continues to provide SCE with opportunities to deliver benefits to its customers by improving the ways it executes its core utility functions.

Finally, customers must play a critical role in bringing about a smarter power system. To support their participation in this effort, SCE's smart grid investments will enable programs like demand response, home energy management and distributed generation that provide customers with information and choice about how they consume electricity.

2. SCE's Smart Grid Strategy Focuses on Enabling Smart Grid Capabilities through Investments in Secure, Interoperable Smart Grid Infrastructure

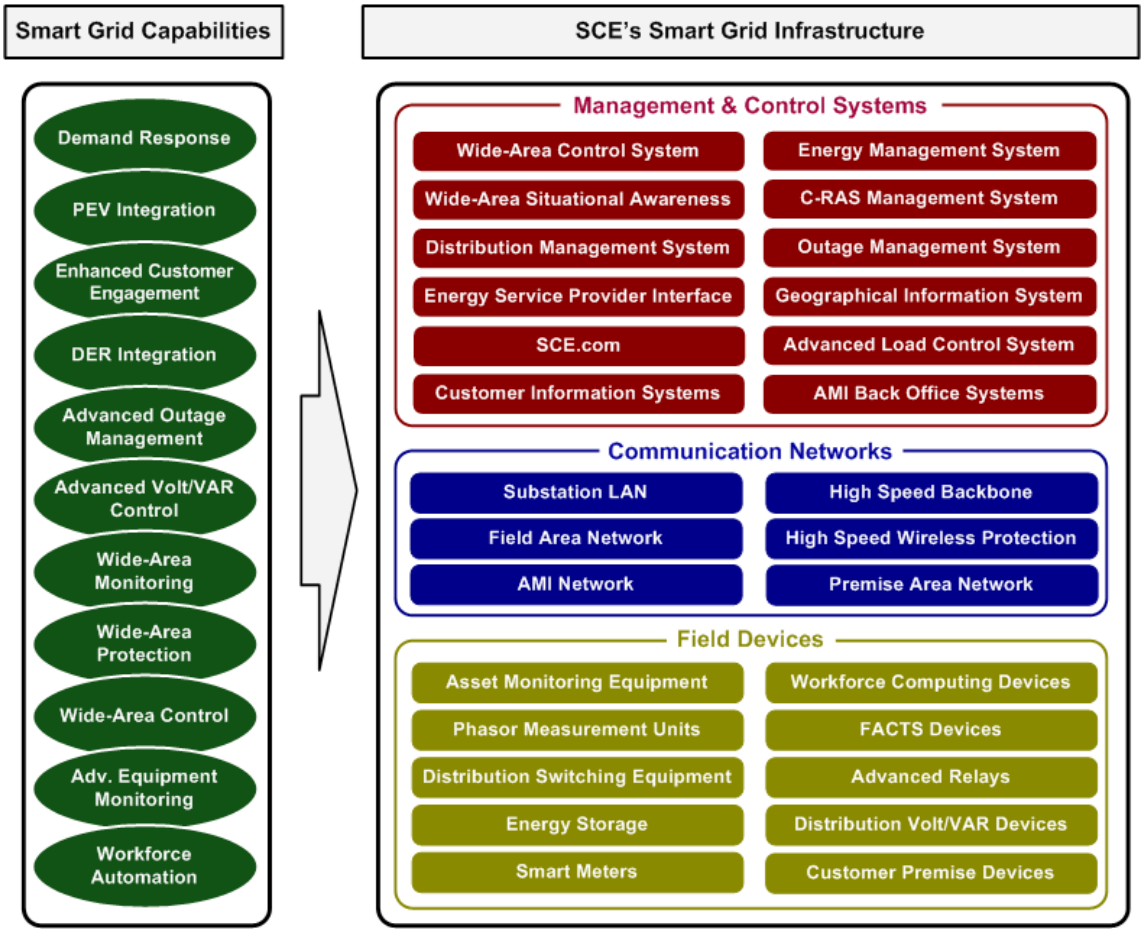
SCE has anchored its strategy for deploying a smarter grid around a set of smart grid capabilities that, collectively, will allow it to meet important energy policy goals, deliver value and engage its customers. Enabling these capabilities will, in turn, require SCE to invest in an integrated set of infrastructure elements. Figure 1 on the next page depicts the smart grid capabilities that SCE has prioritized for this Deployment Plan and the infrastructure elements required to enable them.

At a foundational level, enabling the full range of smart grid capabilities requires SCE to overlay its power system with an information technology network that can securely gather, transmit and process information about SCE's transmission and distribution systems. Deploying this platform infrastructure is a critical first step in delivering a functional, interoperable smart grid that supports the goals of SB 17. On top of this platform, SCE can then make targeted, incremental investments aimed at enabling specific smart grid features.

In deploying this infrastructure, SCE will build interoperability and security into all current and future smart grid systems. Building to interoperability standards is one of the safest approaches to protecting SCE's investments in a rapidly changing technology environment. Beyond the direct benefits to SCE's customers of mitigating the risk of stranded assets, interoperability standards also promote the development of robust markets for products and services that can benefit customers in ways not yet perceived. Standards are also a key tool for ensuring that sensitive operational and customer data are protected as smart grid deployments increase the flow of information across the power system.

Cyber security is also a foundational element of SCE's smart grid plans. In the period covered by the Deployment Plan and beyond, SCE will equip an unprecedented number of field devices with communications capabilities. In addition, utilities across the nation and particularly in the Western

Figure 1 – SCE's Smart Grid Capabilities and Infrastructure



Electricity Coordinating Council will deploy their own smart grid systems to which SCE will connect. The devices within these interconnected systems will transmit sensitive information about transmission and distribution systems, and SCE's system operators will make real-time decisions based on this information.

Protecting the integrity of this information as SCE deploys smart grid systems is a main driver of SCE's focus on cyber security. Cyber security elements will be built into all devices and systems as they are deployed in the field. In addition, to effectively manage cyber security of these disparate and varied devices and the systems that serve them, SCE will invest in centralized integration, coordination and monitoring technologies that will ensure the cyber security of SCE's grid.

3. SCE's Near-Term Smart Grid Activities Include Completion of AMI Deployment, Investments in Platform Infrastructure and Preparing the Grid for Renewables

The most important factor informing SCE's near-term smart grid planning is the need to safely and reliably integrate power from distributed and bulk renewable resources. SCE must prepare its transmission

and distribution system for the interconnection of these resources as California moves toward a 33 percent renewable portfolio standard in 2020. To do so, SCE is investing in a foundational information technology platform and specific solutions aimed at addressing the challenges associated with integrating intermittent, renewable resources. These deployments are near-term priorities because SCE's system must be prepared to integrate renewable resources prior to those resources interconnecting and becoming operational.

In parallel with these policy-driven deployments, SCE is focusing on completion of its Edison SmartConnect™ (SmartConnect) advanced metering infrastructure (AMI) deployment. As of the end of May 2011, SCE had installed 2,627,135 SmartConnect meters and expects to complete deployment of these meters by the end of 2012. This cornerstone investment will support a variety of programs that will help SCE's customers become more active participants in the power system and save on their electricity bills.

Finally, SCE is also exploring ways that it can leverage its AMI system and its developing information technology platform to continue supporting energy policy goals and to deploy additional solutions aimed at delivering customer benefits in the long term. SCE is conducting pilots and limited scale deployments of solutions that are expected to deliver benefits like energy savings, avoided or deferred capital investment and enhanced reliability in the future. These internal activities, as well as extensive national smart grid demonstration projects funded by the American Recovery and Reinvestment Act of 2009 (ARRA), will provide important information over the next five years to inform SCE's deployment decisions in the second half of the decade.

4. Near-Term Smart Grid Costs are Required to Achieve AMI-Related Benefits and Integrate Renewable Resources

SCE's near-term smart grid priorities include preparing for the impacts of renewable energy on grid operations, and successfully completing deployment of its SmartConnect meters. SCE's plans for the second half of the decade are less certain, and will depend heavily on insights gained from its own technology evaluations as well as the results of ARRA-funded projects conducted by utilities across the country. Accordingly, this Deployment Plan provides detailed descriptions of SCE's plans for smart grid deployments through the end of 2014 and more conceptual guidance about potential deployments from 2015 through 2020.

The descriptions of near-term deployments are based on projects that were included in SCE's 2012 GRC Phase 1 Application,[2] SCE's 2012-2014 Demand Response Application,[3] and SCE's Summer Discount

2 A. 10-11-015.
3 A. 11-03-003.

Plan Application filed in June 2010.[4] These investments are primarily focused on building smart grid capabilities into platform infrastructure, enabling key renewable energy policy goals and empowering customers to engage more actively in their energy consumption through demand response and other AMI-enabled programs.

Table 1 below summarizes the remaining costs of SCE's SmartConnect program, as well as projected costs associated with investments in platform and incremental smart grid infrastructure through 2014. It should be noted that while the platform investments summarized below are critical for enabling smart grid capabilities, many of these investments also serve "non-smart grid" utility functions. As a result, the costs of these platform investments are not fully attributable to smart grid capabilities. This document's Cost Estimates chapter contains additional information about the forecasted costs of certain projects in 2015 and beyond. Many such projects, however, are highly speculative in nature and SCE is therefore not able to provide estimates for all projects in this time period.

Table 1 – SCE Smart Grid Cost Estimates

	Annual Costs ($ million, nominal)				
Deployment Category	**2011**	**2012**	**2013**	**2014**	**Total**
Edison SmartConnect™	$ 435	$ 368	$ -	$ -	**$ 803**
Platform Infrastructure	$ 73	$ 117	$ 167	$ 174	**$ 532**
Incremental Investments	$ 138	$ 165	$ 122	$ 110	**$ 535**

The key benefits of the smart grid deployments summarized above include enabling energy policy goals and delivering energy and capacity savings through programs identified in SCE's SmartConnect business case. Specifically, the benefits of these near-term deployments include the following:

- Safe and reliable integration of bulk and distributed renewable energy resources;
- Safe and reliable integration of electric vehicle charging into grid operations;
- 1,900 MW of demand response program enrollment by 2014;
- 1,000 MW of AMI-enabled demand reduction by 2017;
- Over 250,000 MWh per year of energy savings by 2014 through AMI-enabled programs; and
- Improved customer satisfaction through better response to outages, better management of transmission and distribution assets, and more choices for customers in managing their energy usage.

SCE sees substantial additional long-term value in deploying a smarter grid. The platform investments it is making now are a down payment towards those benefits. This Deployment Plan's Benefits Estimates chapter provides a qualitative discussion of these longer term benefits. SCE expects to provide additional

4 A. 10-06-017.

detail about these benefits in future General Rate Cases and Deployment Plan updates as current demonstration activities provide insights that will inform future analyses and proposals.

5. Organization of SCE's Deployment Plan

Consistent with the Commission's guidance in D. 10-06-047, SCE has organized its Deployment Plan into the following seven chapters[5]:

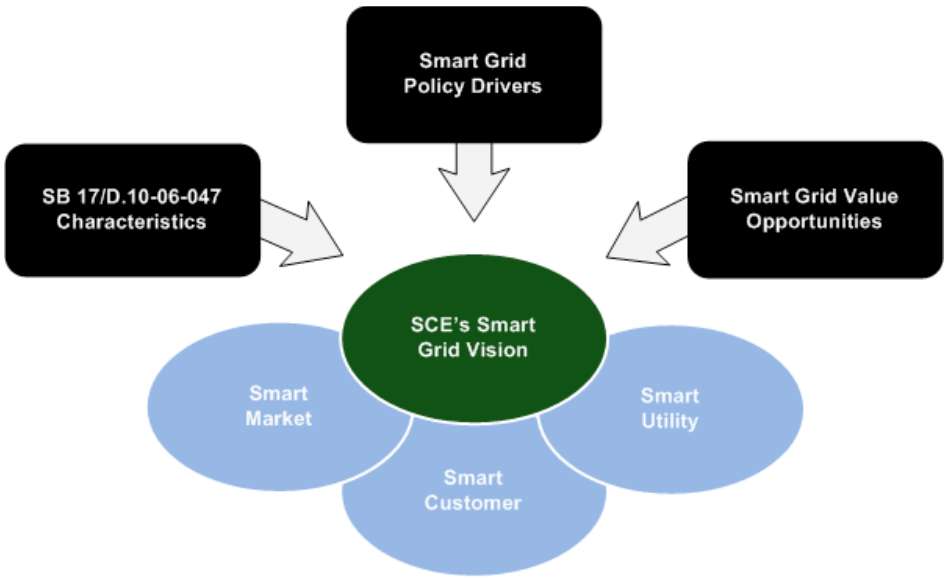
1. Smart Grid Vision
2. Smart Grid Strategy
3. Deployment Baseline & Smart Grid Roadmap
4. Cost Estimates
5. Benefits Estimates
6. Grid Security and Cyber Security Strategy
7. Metrics

The following sections summarize content that SCE presents throughout the rest of its Deployment Plan.

a) Smart Grid Vision

The Vision chapter of SCE's Deployment Plan identifies the key drivers that shape SCE's plans for smart grid deployments. These drivers include (1) the smart grid characteristics and goals that were codified by California's Legislature in SB 17 and adopted by the Commission in D. 10-06-047, (2) state energy policies

Figure 2 – SCE's Smart Grid Vision and Drivers



5 See D. 10-06-047, Ordering Paragraph No. 2. SCE has reordered the required eight chapters, and combined two – Deployment Baseline and Smart Grid Roadmap – for ease of presentation.

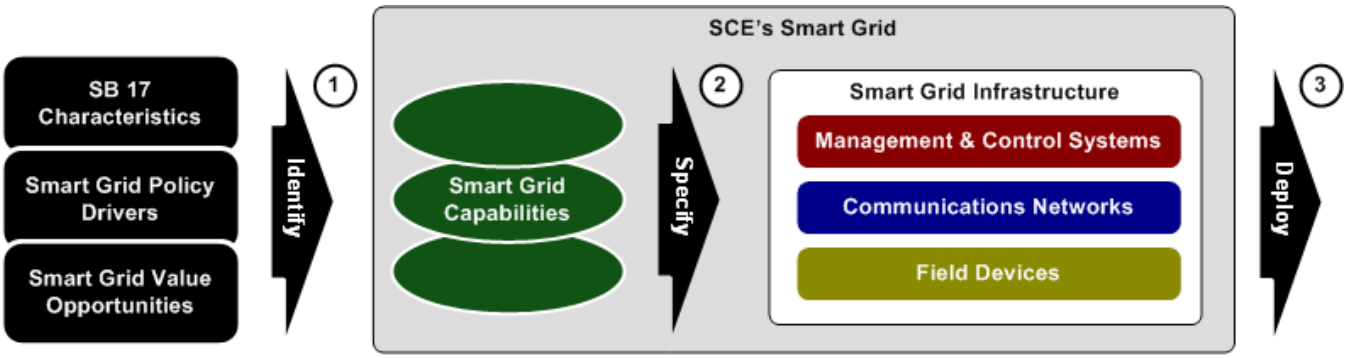
that create a need for smart grid technology solutions, and (3) opportunities for SCE to leverage smart grid technologies to create value for its customers. Consistent with the specific requirements of D. 10-06-047, SCE's Vision chapter also includes a discussion of the roles of a smart market, smart customers and a smart utility in realizing a smarter grid.

b) Smart Grid Strategy

The Strategy Chapter of the Deployment Plan presents SCE's strategy for deploying a smart grid in a way that complies with SB 17, meets relevant policy goals and achieves reasonable value for customers. SCE defines a smart grid as a combination of both the smart grid capabilities – SCE's ability to operate in a certain manner or provide a set of functions – and the infrastructure – in the form of management and control systems, communications networks and field devices – required to enable these smart grid capabilities. Within this framework, the Strategy chapter describes the three elements of its smart grid deployment strategy that are listed below and summarized in Figure 3:

1. Identify key smart grid capabilities that SCE must enable to address the smart grid policy drivers identified in the Vision chapter;
2. Specify the types of infrastructure required to enable these capabilities; and
3. Evaluate the deployment readiness of this infrastructure.

Figure 3 – SCE's Smart Grid Strategy



This presentation of SCE's smart grid strategy includes a discussion of specific issues related to standards, customer privacy and utilization of commercial telecommunications networks as required by D. 10-06-47.

c) Deployment Baseline & Smart Grid Roadmap

Based on the smart grid strategy defined in the chapter above, SCE's Deployment Baseline and Smart Grid Roadmap chapter describes SCE's specific plans to deploy smart grid technologies through the year 2020. For each of SCE's smart grid capabilities, this chapter describes (1) SCE's rationale for focusing on that capability, (2) the infrastructure required to deliver that capability in the future, and (3) the current status of

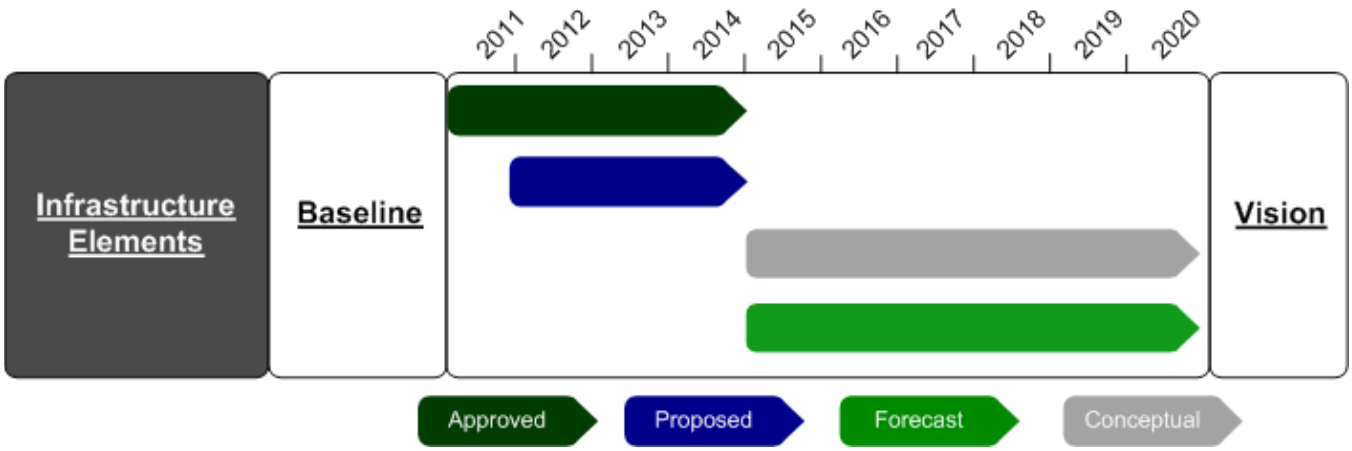
SCE's ability to deliver the capability and the future plans for deploying enabling infrastructure.

In describing the importance of each smart grid capability, SCE explicitly links each to the smart grid characteristics and goals identified in SB 17 and adopted by the Commission in D. 10-06-047. Each capability also maps directly to one or more of the policy and value drivers identified in the Vision chapter.

SCE then describes, at a high level, the type of infrastructure that will be required to enable each capability. These infrastructure elements include management and control systems, communications networks and field devices that will have to work together for SCE to achieve a given capability.

Finally, SCE presents qualitative and quantitative descriptions of its current progress (as of December 31, 2010) towards delivering each capability and deploying the infrastructure required to do so. This baseline includes a description of SCE's existing practices concerning privacy and security of customer data. SCE then describes, based on principles laid out in the Smart Grid Strategy chapter, its plans to deploy additional infrastructure for each capability.

Figure 4 – SCE's Smart Grid Roadmap



These planned infrastructure deployments are organized into deployment projects, which are in turn grouped into the following categories (summarized in Figure 4) to reflect SCE's level of certainty about the readiness for deployment of the underlying infrastructure:

1. Approved – The Commission has already authorized funding for these projects and deployment will continue through part of the period covered by the Deployment Plan.
2. Proposed – SCE has proposed these projects in applications pending before the Commission.
3. Forecast – These projects represent continuations of deployment activities in either approved or proposed projects beyond the periods for which they have received Commission approval or been proposed. Most of these projects start in 2015 or after.

4. Conceptual – These projects include existing technologies where the scope of future deployments is uncertain, as well as technologies that SCE does not think are currently deployment-ready.

d) Cost Estimates

In the Cost Estimates chapter, SCE forecasts costs associated with the infrastructure deployments described in the Deployment Baseline & Smart Grid Roadmap chapter. Consistent with D. 10-06-47 and the categories of projects identified in the Deployment Baseline & Smart Grid Roadmap chapter, these estimates reflect decreasing certainty towards the end of the period covered by the Deployment Plan. Table 2 below summarizes the estimating methodology that SCE uses for each type of project identified in the Deployment Baseline & Smart Grid Roadmap chapter

Table 2 – SCE's Cost Estimating Approach

Roadmap Project Type	Estimating Metholodgy
Approved	Point Estimates
Proposed	Point Estimates
Forecast	Cost ranges, +/- 45%
Conceptual	Assumptions are too uncertain for reasonable estimates

e) Benefits Estimates

In the Benefits Estimates chapter, SCE discusses benefits that it expects to achieve by pursuing each smart grid capability. This benefit discussion is consistent with guidance provided in D. 10-06-047, which identifies three types of smart grid benefits that IOUs should discuss in their Deployment Plans: (1) achievement of policy requirements, (2) benefits beyond simple policy compliance, and (3) benefits like reliability and safety that are difficult to quantify, but which should be estimated where possible.

f) Grid Security and Cyber Security Strategy

As required by D. 10-06-047, SCE has included in its Deployment Plan a Grid Security and Cyber Security Strategy chapter. This chapter presents SCE's approach to evaluating, preventing and addressing security threats that it expects to emerge as it deploys a smart grid. The chapter addresses requirements and questions that are identified in D. 10-06-47, including questions relating specifically to the security of customer data.

g) Metrics

In the final chapter of its Deployment Plan, SCE reports values as of December 31, 2010 for the consensus metrics that were described in the *Report on Consensus and Non-Consensus Smart Grid Metrics* submitted by SCE, Pacific Gas and Electric Company and San Diego Gas & Electric Company, in consultation with Environmental Defense Fund (EDF).

II. Glossary

AB 32	California Assembly Bill 32, "The Global Warming Solutions Act of 2006"; requires California to reduce greenhouse gas (GHG) emissions to 1990 levels by the year 2020
ALCS	Advanced Load Control System
AMI	Advanced Metering Infrastructure
ARRA	American Recovery and Reinvestment Act of 2009
C&I	Commercial and Industrial, refers to a class of SCE customers
CAISO	California Independent System Operator
CEC	California Energy Commission
Commission, or CPUC	California Public Utilities Commission
CPP	Critical Peak Pricing (see Dynamic Pricing Rates below)
C-RAS	Centralized Remedial Actions Scheme
CSI	California Solar Initiative
D. 10-06-047	California Public Utilities Commission decision adopting Requirements for Smart Grid Deployment Plans Pursuant to Senate Bill 17 (Padilla), Chapter 327, Statutes of 2009
Deployment Plan	SCE's Smart Grid Deployment Plan, submitted pursuant to D. 10-06-047
DG	Distributed Generation
DMS	Distribution Management System
DR	Demand Response
Dynamic Pricing Rates	A “dynamic pricing rate” means either (1) a critical peak pricing (CPP) rate schedule where rates or charges vary by TOU periods during the day and by season with a much higher-priced energy charge that applies to some or all of the customer’s energy usage during a critical peak pricing event period, and a credit is provided to usage outside critical peak periods; or (2) real-time pricing (RTP), a rate schedule in which rates adjust frequently, typically every hour, to reflect real-time system conditions.
EAP	California Energy Action Plan
EE	Energy Efficiency
ESPI	Energy Service Provider Interface
EVSE	Electric Vehicle Service Equipment
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
HAN	Home Area Network
ISGD	Irvine Smart Grid Demonstration project

Legislature	The California State Legislature
MW	Megawatt
OIR	Order Instituting Rulemaking
OTC	Once through Cooling
PEV	Plug-in Electric Vehicle
PMU	Phasor Measurement Unit
PV	Photovoltaic; a method of generating electric power from solar radiation
RCS	Remote Control Switch
RPS	Renewable Portfolio Standard
SB 17	California Senate Bill 17, Chaptered October 2009 and Codified at Pub. Util. Code § 8360
SCE	Southern California Edison Company
SGIP	Self-Generation Incentive Program
State Water Board	California State Water Resources Control Board
TOU	Time of Use; refers to rates that consist of several pre-defined time periods and charge customers different pre-determined rates during each time period. For example, during the summer, the rate charged during the afternoon is generally higher than the rate charged at night. The different rates reflect the fact that it is generally more expensive to serve customers during some time periods. TOU rates do not change based on current market conditions. The Commission does not characterize a TOU rate by itself as a dynamic pricing rate because the rates do not change based on day-ahead or real-time market or system conditions.
TSP	Tehachapi Energy Storage Project, an ARRA-funded project that will demonstrate performance of a 8 MW / 4 hr (32 MWh) lithium ion battery storage system the Tehachapi Wind Resource Area
URCI	Universal Remote Control Interrupter, as fast-acting distribution system switching device
VAR	Volt-ampere reactive; a unit used to measure reactive power in an AC electric power system
WASAS	Wide Area Situational Awareness System
WECC	Western Electricity Coordinating Council
Western Interconnection	The Western Interconnection is one of the two major alternating current (AC) power grids in North America. All of the electric utilities in the Western Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency of 60Hz. The Western Interconnection stretches from Western Canada south to Baja California in Mexico, reaching eastward over the Rockies to the Great Plains.

III. Smart Grid Vision

In its April 2010 *Smart Grid Strategy & Roadmap*,[6] SCE published the smart grid vision statement below. SCE continues to pursue this vision of a smarter electric grid today. Electric utilities across the Unites States, and particularly in California, stand at the convergence of two fundamentally industry-altering trends. First, state and federal policy goals focused on cleaner electric power are forcing utilities to rethink the way electricity is produced and delivered. At the same time, advances in energy, information and communication technologies provide utilities and their customers with new tools for achieving these policy goals and unlocking value throughout the electric power system. SCE's smart grid vision is meant to enable this future in which utilities leverage new technologies reliably and cost effectively to deliver cleaner energy, operate more effectively and empower customers to take an active role in their electricity consumption.

> *"SCE's vision of a smart grid is to develop and deploy a more reliable, secure, economic, efficient, safe and environmentally-friendly electric system. This vision covers all facets of energy from its production to transmission, distribution, and finally its efficient use in homes, businesses and vehicles. This smart grid will incorporate high-tech digital devices throughout the transmission, substation and distribution systems and integrate advanced intelligence to provide the information necessary to both optimize electric service and empower customers to make informed energy decisions."*[7]

This chapter sets forth SCE's smart grid vision in terms of the characteristics a smart grid should have, the policies it should enable, and the value it should deliver. Specifically, Section A identifies the smart grid characteristics that the Commission adopted in D.10-06-047, and describes in more detail the policies and value opportunities that SCE sees as critical drivers of its smart grid vision. Following this discussion of the driving forces underlying SCE's smart grid vision, consistent with D.10-06-047, SCE presents a vision of three key "actors" – the smart market, the smart customer and the smart utility – in a smart grid future.

A. Smart Grid Characteristics and Drivers

The case for utility investment in a smarter grid rests on two primary drivers: enabling energy policy goals and delivering value. Several energy policies at the state and federal level, mostly focused on reducing the environmental impact of the electric power system, drive the need for utility investment in a smarter grid. Concurrent with the development of these policies, the past several decades have seen tremendous

6 Available at: http://asset.sce.com/Documents/Environment percent20- percent20Smart percent20Grid/100712_SCE_SmartGridStrategyandRoadmap.pdf.

7 Southern California Edison, Smart Grid Strategy & Roadmap, p. 6.

advances in energy, information and communication technologies. These advances now present SCE with the opportunity to deliver value by creating a smarter grid that will operate more efficiently and effectively.

In D.10-06-047, the Commission adopted a set of 11 smart grid characteristics that encompassed prior federal and state policy statements about the need for a smarter grid. These 11 characteristics effectively capture the policy and value drivers that are pushing utilities to invest in a smarter grid. Part 1 of this discussion of smart grid drivers restates and gives some context to these 11 smart grid characteristics. In part 2 of this section, SCE describes in more detail the key policies reflected in these 11 characteristics that have influenced SCE's vision for the smart grid. Finally, in part 3 of this section, SCE describes the opportunities to unlock value that are embedded in the Commission's smart grid characteristics and that SCE believes it can achieve through investing in a smarter grid.

1. D.10-06-047 Smart Grid Characteristics

The state and federal policies that launched California on a path toward a smart grid culminated in the enactment of SB 17, signed into law on October 11, 2009. Drawing on prior statements of smart grid policy at the federal level in section 1301 of the Energy Independence and Security Act of 2007 (EISA), section 8360 of SB 17 identified ten goals for the smart grid in California. In both the February 8, 2010 Assigned Commissioner and Administrative Law Judge's Joint Ruling Amending Scoping Memo and Inviting Comments on Proposed Policies and Findings Pertaining to the Smart Grid and in D. 10-06-047, the Commission distilled the smart grid goals codified in EISA and SB 17 into the following eight requirements. The following quotes D. 10-06-047:

- Be self-healing and resilient – Using real-time information from embedded sensors and automated controls to anticipate, detect, and respond to system problems, a smart grid can automatically avoid or mitigate power outages, power quality problems, and service disruptions.[8]
- Empower consumers to actively participate in operations of the grid – A smart grid should enable consumers to change their behavior around dynamic prices or to pay vastly increased rates for the privilege of reliable electrical service during high-demand conditions.[9]
- Resist attack – A smart grid system should better identify and respond to man-made or natural disruptions. A smart grid system using real-time information should enable grid operators to isolate affected areas and redirect power flows around damaged facilities.[10]

8 Summary of Pub. Util. Code § 8360(a) - (b), & (d); § 8366(a), (e) - (g) in D. 10-06-047, pp. 30-31.
9 Summary of Pub. Util. Code § 8360(c) - (g), & (h); § 8366(a) - (d) in D. 10-06-047, p. 31.
10 Summary of Pub. Util. Code § 8360(a) - (b), & (d); § 8366(a), (e) - (g) in D. 10-06-047, p. 31.

- Provide higher quality power that will save money wasted from outages – A smart grid system should create and provide more stable and reliable power to reduce downtime.[11]
- Accommodate all generation and storage options – A smart grid system should continue to support traditional power loads, and also seamlessly interconnect with renewable energy, micro-turbines, and other distributed generation technologies at local and regional levels.[12]
- Enable electricity markets to flourish – A smart grid system should create an open marketplace where alternative energy sources from geographically distant locations can easily be sold to customers wherever they are located. Intelligence in distribution grids should enable small producers to generate and sell electricity at the local level using alternative sources such as rooftop-mounted photo voltaic panels, small-scale wind turbines, and micro hydro generators.[13]
- Run more efficiently – A smart grid system should optimize capital assets while minimizing operations and maintenance costs (optimized power flows reduce waste and maximize use of lowest-cost generation resources).[14]
- Enable penetration of intermittent power generation sources – As climate change and environmental concerns increase, the demand for renewable energy resources will also increase; since these are for the most part intermittent in nature, a smart grid system should enable power systems to operate with larger amounts of such energy resources.[15]

In addition to those eight Smart Grid requirements, the Commission also adopted, in D. 10-06-047, three additional recommendations made by the Environmental Defense Fund (EDF). The additional requirements are that a smart grid:[16]

- Enable maximum access by third parties to the grid, creating a welcoming platform for deployment of a wide range of energy technologies and management services;
- Have the infrastructure and policies necessary to enable and support the sale of demand response, energy efficiency, distributed generation, and storage into energy markets as a resource among other things, on equal footing with traditional generation resources; and
- Significantly reduce the total environmental footprint of the current electric generation and delivery system in California.

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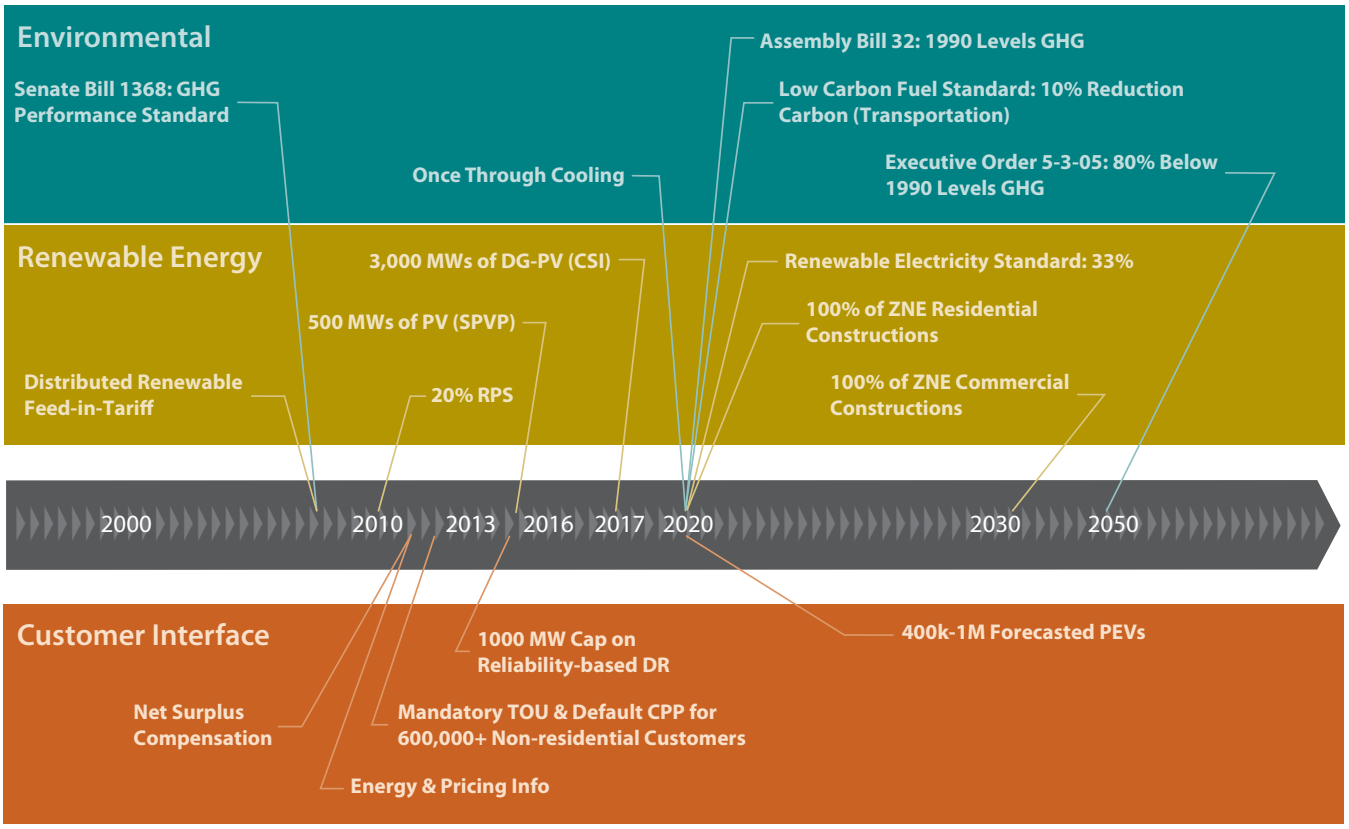
11 Summary of Pub. Util. Code § 8360(a) - (b); § 8366(a), (e) - (g) in D. 10-06-047, p. 31.
12 Summary of Pub. Util. Code § 8360(b) - (g); § 8366(a), (e) - (g) in D. 10-06-047, p. 31.
13 Summary of Pub. Util. Code § 8360(b) - (j); § 8366(a) – (d) in D. 10-06-047, p. 31.
14 Summary of Pub. Util. Code § 8360(a); § 8366(g) in D. 10-06-047, pp. 31-32.
15 Summary of Pub. Util. Code § 8360(c), (g), &(j); § 8366(a) - (d) in D. 10-06-047, p. 32.
16 D. 10-06-047, p. 34.

These 11 smart grid characteristics capture what SCE views as the critical policy and value drivers of smart grid investments. These drivers are discussed in more detail below.

2. Smart Grid Policy Drivers

California's energy and environmental policies are driving the development of a smarter, cleaner, and more robust electricity infrastructure. These policies will require substantial investments from SCE. Figure 5 below summarizes the current California policies affecting smart grid development. These energy policies drive the need for smart grid investments in several ways. First, some policies such as the Renewables Portfolio Standard and distributed generation incentives create conditions that make it more difficult for SCE to operate its system reliably. In these cases, smart grid investments are required to help SCE address the technological challenges associated with enabling these important policies. Second, other policies, such as the Energy Action Plan or D. 09-12-046 in the Smart Grid OIR encourage or mandate specific actions that SCE must take or programs that it must deliver. In these cases, smart grid investments provide SCE a means for delivering these actions and programs. The sections below describe the key policies that are driving smart grid investment and the specific ways that each policy drives smart grid solutions.

Figure 5 – California Smart Grid Policy Timeline



a) Assembly Bill 32

Most notable among California's ambitious environmental policy statutes is Assembly Bill (AB) 32 (Nuñez, 2006), also known as the Global Warming Solutions Act of 2006. AB 32 requires California to reduce greenhouse gas (GHG) emissions to 1990 levels by the year 2020.[17] This bill is accompanied by Executive Order S-3-05, which was issued by Governor Schwarzenegger in 2005 to create the long-term goal of reducing GHG emissions 80 percent below 1990 levels by 2050. In December 2008 pursuant to AB 32, the California Air Resources Board (CARB) published a Climate Change Scoping Plan. The Scoping Plan identifies several recommended actions, some of which have already been adopted by the State, to facilitate achievement of AB 32's goals in a cost-effective manner. Key elements of these recommendations in which utilities play a significant role include:[18]

- Expanding and strengthening existing energy efficiency programs as well as building and appliance standards;
- Achieving a statewide renewables energy mix of 33 percent; and
- Establishing targets for transportation-related GHG emissions for regions throughout California and pursuing policies to achieve those targets.

With respect to energy efficiency (EE), smart grid technologies can play a key role in increasing the efficiency of electricity consumption in the State. As further discussed in the Renewable Portfolio Standard section below, achieving a 33 percent renewable portfolio target will greatly increase the complexity of operating the electric transmission and distribution system and smart grid technologies can help address this complexity. Finally, the AB 32-based push to reduce transportation emissions is likely to drive adoption of electric vehicles (EVs), which will also create for electric utilities challenges that a smarter grid can address.

b) Renewables Portfolio Standard

The California Renewables Portfolio Standard (RPS) was established in 2002 by Senate Bill 1078 (Sher) to require California investor-owned utilities (IOUs) to obtain 20 percent of their electricity from clean and renewable energy sources by 2010. In 2008, the Governor signed Executive Order S-14-08 requiring that California utilities achieve 33 percent RPS by 2020. Earlier this year, the California Legislature passed Senate Bill X1-2, which Governor Brown signed on April 11, 2011. This bill codifies the 2020 target of 33 percent RPS.

Using renewable sources to fuel 33 percent of its electricity deliveries will create several challenges

17 http://www.arb.ca.gov/cc/ab32/ab32.htm.

18 CARB, *Climate Change Scoping Plan: A Framework for Change*. (December 2008), http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf.

for SCE. First, much of this renewable power is expected to come from intermittent resources, such as wind and solar. The intermittent nature of these resources is likely to create stability problems on the bulk power system and on distribution circuits with high concentrations of solar photovoltaics (PV). The smart grid technologies discussed later in this document can help mitigate these stability problems. In addition, renewable portfolio targets in California and throughout the West will increase the number of generation interconnections in geographically dispersed locations, as developers complete construction of new solar arrays and wind farms in areas where those resources are available. This increased number of interconnections will dramatically increase the complexity of operating the bulk power system and smart grid technologies can help SCE manage this complexity.

c) Once Through Cooling

Adding to the complexity of high penetrations of intermittent resources is the move to restrict once through cooling (OTC) in coastal generating plants. In October 2010, the State Water Resources Control Board (State Water Board) enacted its *Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*.[19] The policy effectively states that OTC systems do not meet Federal standards for water use. As a result, power plants in the state that use OTC systems must either retrofit to a closed-cycle cooling process or cease operation. Loss of this generation would create many system stability problems in SCE's service territory and SCE is assessing a range of technologies that may help address these issues.

d) Distributed Generation Programs

To facilitate compliance with AB 32 and RPS legislation, policymakers have focused on expanding the use of distributed renewable energy sources. Over the past several years, the CPUC has created several utility programs that provide incentives or cost recovery for installations of distributed renewable generation facilities, including the Go Solar California! campaign. Go Solar California! is a joint effort by the CEC and the CPUC that aims to install 3,000 megawatts (MW) of solar energy systems on homes and businesses by the end of 2016, via programs such as the California Solar Initiative (CSI) and New Solar Homes Partnership.[20] Additionally, the CPUC approved SCE's 500 MW Solar Photovoltaic Program (SPVP)[21], which requires solar PV developments totaling up to 250 MW of utility owned generation and another 250 MW of

19 Available at: http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/policy100110.pdf.

20 http://www.gosolarcalifornia.ca.gov/about/index.php.

21 On February 11, 2011, SCE filed a Petition for Modification of the SPVP Decision D. 09-06-049 with the Commission. If approved as filed, the program will be modified to 125 MW Utility-Owned Generation, 125 MW original Independent Power Producer (IPP) program, and a third solicitation "IPP Revised" to be created for 250 MW IPP not limited to constraints of the original SPVP.

power purchase agreements in SCE's service territory by 2014.[22] In addition to solar programs, the CPUC's Self-Generation Incentive Program (SGIP) provides rebates for qualifying distributed energy systems installed on the customer side of a utility meter. SGIP qualifying technologies include wind turbines, fuel cells, and energy storage systems.[23] Finally, in 2009, SB 32 (Negerete, McLeod) was signed into law, increasing the size of generation facilities eligible for California's feed-in tariff program from 1.5 MW to 3 MW and increasing the statewide cap for enrollment in feed-in-tariffs from 500 MW to 750 MW.

Widespread adoption of intermittent distributed generation (DG), such as solar PV, presents two specific challenges for distribution system operations. First, increased penetration of DG increases the severity of voltage problems on distribution circuits. These fluctuations make it harder for SCE to deliver power to its customers at the required voltage. The second problem relates to the capacity of the distribution infrastructure that will have to serve these DG facilities. The presence of DG will strain this equipment, potentially forcing SCE to make costly unanticipated upgrades of this infrastructure. SCE will need smart grid technologies to address both of these problems associated with full implementation of the state's many DG programs.

e) Plug-In Electric Vehicle Policies

As noted above in the discussion of AB 32, implementation of this landmark legislation will involve reducing emissions associated with the transportation sector as well as the power sector. One option that policymakers are considering to address transportation emissions is promoting the use of alternative transportation fuels, including electricity. Several specific policies have been adopted or proposed that would facilitate an increasing reliance on electricity as a transportation fuel. Most prominently, President Obama set a goal of one million plug-in electric vehicles (PEVs) on the road by 2015, which was reinforced by the America Recovery and Reinvestment Act (ARRA) with expanded federal tax credits for PEVs as well as $2.4 billion in grants and $8 billion in loans for PEV programs[24].

At the state level, Governor Schwarzenegger's Executive Order S-1-07 called for a reduction of the carbon impact of California's transportation fuels by 10 percent by 2020, and is expected to encourage increased reliance on electricity to power vehicles. California also has a requirement for automakers to produce zero-emission vehicles (ZEVs) which includes both EVs and plug-in hybrid electric vehicles. Similarly, in 2005, AB 1007 (Paley) required the CEC to prepare a state plan to increase the use of alternative fuels

22 The CPUC authorized SCE's PV program in D. 09-06-049 and Resolution E-4299. More information is available at: http://www.cpuc.ca.gov/PUC/Templates/RPS.aspx?NRMODE=Published&NRNODEGUID={5C37AA16-4349-4EFC-AE5D-1597AD1DB13E}&NRORIGINALURL= percent2fPUC percent2fenergy percent2fRenewables percent2fhot percent2fUtility percent2bPV percent2bPrograms percent2ehtm&NRCACHEHINT=Guest#SCE.

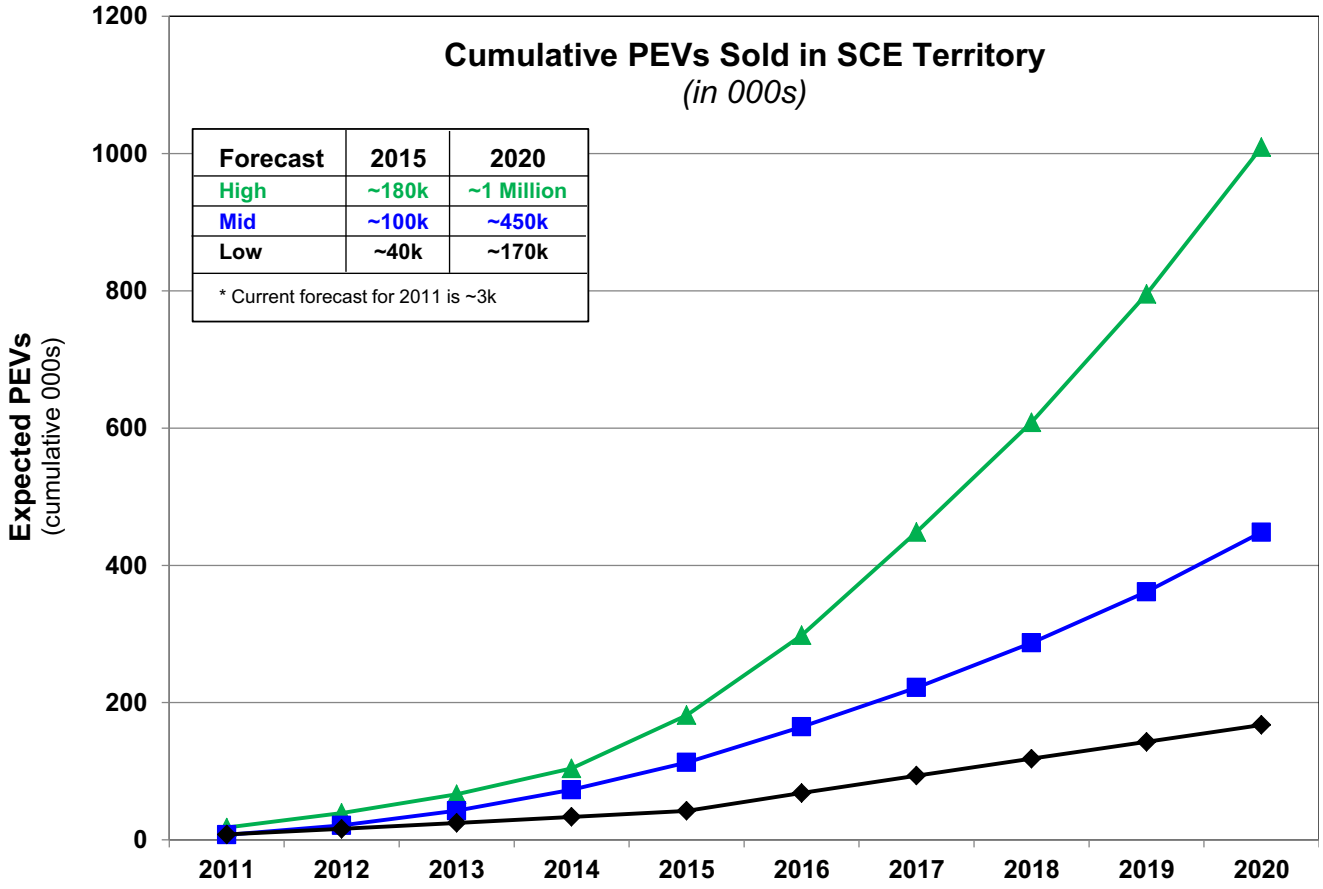
23 http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/.

24 Department of Energy, One Million Electric Vehicles by 2015: February 2011 Status Report, http://www.energy.gov/media/1_Million_Electric_Vehicle_Report_Final.pdf.

in California. The resulting State Alternative Fuels Plan, adopted in 2007, includes a strategy to develop hybrid and EV technologies. In 2007, California also adopted a grant program (AB 118) which provides $1.4 billion over 7 years to alternative fuel vehicle (AFV) programs including PEVs. And finally in 2008, SB 626 was adopted which directed the CPUC to assess and remove barriers to widespread use of PEVs, and has resulted in the current AFV OIR (R.09-08-009). Based on these policy drivers and customer tastes, SCE projects meaningful volumes of PEVs in its service territory over the next decade.

Figure 6 illustrates SCE's forecast for PEV penetration in its service territory through 2020. With major commercial PEV releases already from General Motors and Nissan and another 15 to 20 new PEV models launching in the next four years, SCE expects anywhere from 200,000 to 1 million PEVs in its service territory by 2020. While this range reflects substantial uncertainty, PEV adoption by SCE's customers could cause substantial expense if PEV charging occurs in the wrong places at the wrong times, or without proper notification and integration. In the future, SCE will accommodate its customers' option to purchase PEVs in part through smart grid investments which will help integrate customer vehicle charging into overall grid operations.

Figure 6 – Forecast of PEVs in SCE's Service Territory



f) California Long Term Energy Efficiency Strategic Plan, Energy Action Plan and Sections 454.5 and 454.55 DR and EE Goals

Whereas the policies described above tend to create operational challenges that smart grid technologies can help solve, other energy policies encourage or mandate certain programs that SCE can better provide with smart grid technologies. For example, California's Energy Action Plan (EAP) focuses on EE and demand response (DR) as solutions that the state should pursue in its efforts to achieve GHG reductions under AB 32. The EAP, as updated,[25] recommends engaging customers in active energy management through actions such as:

- Implementing dynamic pricing for all customers;
- Adopting DR for all customers; and
- Educating customers about the time sensitivity of energy use and the ways to take advantage of dynamic pricing and other DR tariffs.[26]

Similarly, the California Long Term Energy Efficiency Strategic Plan focuses on energy efficiency programs that will produce long-term savings and transform the market, including the requirement that all new residential construction in California will be zero net energy (ZNE) by 2020 and all new commercial construction will be ZNE by 2030.[27]

Finally, section 454.5 of the California Public Utilities (P.U.) Code requires that a utility "first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible,"[28] and section 454.55 requires that the Commission, in consultation with the CEC, establish EE targets for each IOU to achieve.[29]

SCE can leverage smart grid investments to enhance its EE and DR offerings to achieve these important policy goals.

g) Demand Response Policy Goals

While California's EAP and Public Utilities Code section 454.5 drive adoption of DR as an alternative to conventional generation resources, several key policy requirements are specifically influencing the way

25 The original EAP was approved in 2003 by the CPUC, CEC, and the now defunct Consumer Power and Conservation Financing Authority (CPA). In 2005, the CPUC and CEC adopted a second EAP and updated it again in 2008.

26 See State of California, Energy Action Plan II, Implementation Roadmap for Energy Policies, Section II.2, "Key Actions," pp. 6-7 (October 2005) (emphasis added) http://docs.cpuc.ca.gov/word_pdf/REPORT/51604.pdf [as of March 1, 2011].

27 CPUC, California Long Term Energy Efficiency Strategic Plan (July 2008); also see D. 08-09-040.

28 Pub. Util. Code § 454.5 (b) (9) (C), http://law.onecle.com/california/utilities/454.5.html.

29 Pub. Util. Code § 454.55, http://law.onecle.com/california/utilities/454.55.html.

SCE implements new DR programs, tariffs, and technologies. These regulatory drivers include:

- Mandatory Transition to Time-Variant and Dynamic Pricing, TOU/CPP rates (D. 09-08-028)

  D. 09-08-028 requires implementation of default dynamic pricing rates and mandatory time-of-use rates for non-residential customers by 2012. These rate changes will profoundly influence the price, usage, and ultimate cost of electricity consumed by roughly 600,000 C&I SCE customer accounts with maximum demands less than 200 kW and approximately 1,200 agricultural and pumping customer accounts greater than 200 kW. This same decision also requires SCE to provide optional dynamic pricing rates for residential customers and real-time pricing rates for all non-residential customers in the same timeframe.

- Increased Delivery of Price-Responsive DR / Cap on Emergency-Based DR

  As stated in the final decision in SCE's 2009-2011 DR Application (D. 09-08-027) and reaffirmed by guidance provided in R.07-01-041, price-responsive DR represents a key priority within the Commission's overall energy policy, because such activities can lower wholesale electricity costs for all customers and help mitigate wholesale market power. In addition, a recent settlement agreement adopted in D.10-06-034 limits the total amount of emergency-based DR that can be counted towards Resource Adequacy. This cap on emergency-triggered DR is set at 3 percent of the CAISO's all-time coincident peak demand in 2012 and decreases to 2 percent by 2014. D.10-06-034 creates a parallel requirement that SCE transitions its almost 600 MW residential Summer Discount Plan Program—one of the largest A/C cycling programs in the U.S.—to a price responsive program that can be bid into CAISO markets.[30]

- Integration of DR with CAISO Wholesale Markets

  The California ISO recently developed two new wholesale market DR product offerings, Proxy Demand Resource (PDR)[31] and Reliability Demand Response Product (RDRP)[32], in response to FERC order 719. These offerings will allow utilities and Demand Response Providers (DRPs) to bid DR on behalf of retail customers directly into the CAISO wholesale electricity markets with the intent of increasing market competition and efficiency as well as improving grid operations. D. 09-08-027 and D.10-06-034 require participation of price responsive and emergency triggered DR programs in their respective wholesale PDR and RDRP offerings. Market integration of DR programs is driving the need for smart grid investments that can provide enhanced geographic or locational

30 *See* A.10-06-017 for more details on the transition of SCE's Summer Discount Plan.

31 *See* CAISO, Draft Final Proposal for the Design of Proxy Demand Resource (PDR) (revised August 28, 2009), http://www.caiso.com/241d/241da56c5950.pdf [as of March 1, 2011].

32 *See* CAISO, Reliability Demand Response Product, Revised Draft Final Proposal, Version 2.0 (October 14. 2010), http://www.caiso.com/281a/281abd55ec00.pdf [as of March 1, 2011].

specificity in how and where these resources are dispatched as well as improved measurement and verification of load reduction as to facilitate market settlement.[33]

h) Customer Access to Usage Information

The CPUC launched the Smart Grid Order Instituting Rulemaking (OIR) in December of 2008 to consider adoption of policies related to smart grid investments by the state's IOUs. In December 2009, the Commission adopted D. 09-12-046, which ordered SCE and the other IOUs to provide (1) an authorized third party with access to the customer's usage information that is collected by the utility and (2) customers with a smart meter access to usage data on a real-time or near real-time basis no later than the end of 2011.[34] This Decision reflects a broader push to provide customers with information about their energy usage to drive conservation. Engaging customers through enhanced information provision is a key element of SCE's smart grid, and the company's smart grid investments will support this policy objective.

3. Smart Grid Value Drivers

As noted earlier, utility investment in smart grid technologies covers a broad range of activities and is driven by a variety of factors. The Smart Grid Policy Drivers section above identifies key policies that either present challenges a smarter grid can help SCE solve or create requirements that SCE can better meet by leveraging smart grid technologies. In addition to helping enable and comply with these policies, a smarter grid also presents an opportunity for SCE to leverage energy, information and communication technologies to unlock value throughout the electric power system.

In the sections below, SCE describes several areas where investment in energy, information and communication technology can enhance its operations, achieve savings and improve the service it provides to customers.

a) Peak Demand Reduction

Peak demand refers to the maximum load, measured in MW, for an electrical system during a given period of time. Peak demand for SCE's service territory in 2009 was just over 22,000 MW. This means that the most power SCE's customers collectively demanded at any point in time during that year was just over 22,000 MW. On average, however, SCE's customers use substantially less power than this amount.

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33 SCE's current market integration plans are presented in the 2012-2014 Demand Response Application (A.11-03-003); however, full implementation and integration of SCE's DR portfolio is dependent on the final rules for DRP participation in CAISO wholesale markets coming out of the Direct Participation phase of the DR OIR.

34 See D. 09-12-046, Ordering Paragraphs 3 and 4. http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/111856.pdf.

In 2009, SCE's system wide load factor was 53 percent, meaning that customer's average demand was 53 percent of the 22,000 MW peak, or approximately 11,600 MW.

To ensure that SCE can effectively serve its customers, the company must build its grid and procure adequate generation resources to accommodate the highest level of demand (i.e. peak load) it expects from its customers. If peak load is materially higher than the average load for SCE's customers, the utility will have to invest in infrastructure that it will use infrequently. Similarly, to serve this peak load, SCE must utilize peaking generators that, according to the 2008 EAP Update are "typically less efficient than most base load power plants" and "contribute disproportionately not only to greenhouse gas emissions but to local air pollution because they operate during hot summer afternoons when local air quality can be poor."[35]

Advances in energy and information technologies present several opportunities for SCE to manage peak load in order to better utilize its transmission and distribution infrastructure and avoid producing or procuring on-peak power. Therefore, the opportunity to reduce peak load is a key driver of SCE's evaluation of, and investment in, smart grid technologies.

b) Energy Conservation

For businesses that use equipment that consumes substantial amounts of electricity, power costs are an important financial consideration, and owners of those businesses tend to be well informed about their electricity usage and its costs. Other electricity customers may think less about their usage and simply plug appliances in and turn them on. Increasing customers' awareness of their energy usage and the costs associated with that usage can help those customers, if they choose to do so, reduce consumption and save money. Smart grid technologies offer a variety of valuable tools to help customers reduce their usage. Thus, energy conservation is a second key driver of SCE's smart grid efforts.

c) Power & Asset Utilization

Due to a lack of actionable information about system conditions, utilities perhaps tend to underutilize transmission assets. Asset utilization refers to the amount of power a utility can push through, for example, a transmission path. In the absence of actionable, real-time information about the condition of the transmission system, utilities must rely on worst case scenario planning as a guide for how heavily they can load a given piece of equipment without risking its failure. These path ratings are generally conservative by necessity – safety is paramount in power system operations – and as a result, they tend to leave "capacity" in the system. Smart grid technologies can provide SCE's operators with better real-

35 *See* 2008 EAP Update, p. 10, available at http://www.cpuc.ca.gov/NR/rdonlyres/58ADCD6A-7FE6-4B32-8C70-7C85CB31EBE7/0/2008_EAP_UPDATE.PDF.

time information about system conditions so that they can safely increase utilization of equipment, and in some circumstances reduce the need for additional investment in expensive transmission and distribution infrastructure.

Similarly, smart grid technologies present utilities with several opportunities to minimize energy losses that occur as power moves from the generator to the customer over the transmission and distribution system. Specifically, a variety of monitoring and control technologies can help SCE reduce these losses and therefore reduce the amount of electricity it has to produce and procure on behalf of its customers.

To capture the value associated with better utilization of transmission and distribution infrastructure and reduced line losses, SCE is focusing on power and asset utilization as a key driver of smart grid investment.

d) Improved Outage Response

Customer outages due to faults and other system disturbances caused by storms, traffic accidents (e.g., cars driving into poles) and other factors are unavoidable. Room for improvement exists, however, with respect to the ability of electric utilities to detect and respond to these outages. Smart grid technologies can provide SCE with information and tools that will allow it to reduce the number of customers affected by these incidents and to return service more quickly to those customers that experience outages. In the future, certain technologies may even allow SCE to anticipate and prevent certain outages altogether. The ability to better respond to, and manage, outages will improve customer satisfaction and is therefore a key driver of SCE's smart grid efforts.

e) Improved Capital Planning

SCE's ability to provide reliable electric service to its customers rests to a large degree on ensuring that infrastructure such as poles, transformers, switches, circuit breakers, capacitors, cable, and conductors are properly maintained. Maintaining this infrastructure is a very expensive undertaking. Until now, SCE has had limited real-time information about the health of specific pieces of equipment to inform its infrastructure maintenance decisions. Smart grid technologies hold the promise of providing SCE personnel with valuable and currently unavailable information about the condition of its service equipment. SCE can use this information to make better and safer decisions about how and when to spend its infrastructure maintenance dollars.

B. Smart Market / Smart Customer / Smart Utility

In D. 10-06-047, the CPUC identified three key entities that must "get smarter" and evolve if we are to advance the smart grid and achieve California and United States policy goals: the market, the customer, and the utility. SCE has expanded its smart grid vision to describe the future state for each of these entities.

1. Smart Market

The Smart Market provides the necessary tools to facilitate activities, such as DR and DG that enable customers to become active participants in the electric grid. Key among the characteristics transforming the current market structure to a Smart Market are enhanced pricing structures and tariffs; information transparency; and enabling technology for the integration of DR, EE, DG, and energy storage into wholesale energy markets.

a) Enhanced Pricing Structures

To facilitate a Smart Market in which pricing structures result in cost-effective DR, DG, and conservation responses, cost-based prices are necessary. Cost-based pricing results in energy prices that are more closely correlated to the real cost of energy at the time the energy is used than currently used flat-rate structures. These time-variant prices indicate to a customer that the cost to use energy varies throughout the day and during different seasons.

Time-variant pricing should be understandable to customers and enable them to manage their energy consumption and costs. If a customer knows that energy costs more at a certain time, they may be more willing to shift their load to a time when energy costs less, reduce their load, or install on-site generation to supply all or some of their load. Time-of-use (TOU) rates have pre-established prices for energy at different times of day and different times of the year. More complex dynamic pricing structures, such as Critical Peak Pricing (CPP) and Real-Time Pricing (RTP), vary the cost of energy in response to certain market conditions or other events. Ultimately, TOU and dynamic rates will result in increased participation in DR programs, DG (including energy storage), and energy conservation.

In addition to time-variant prices, the Smart Market also leverages financial incentives to encourage customers to participate in programs that reduce the amount of load to be supplied by the utility. Incentives for DG offered through the CSI and SGIP have already significantly increased the amount of DG in California and will continue to do so. Incentives for energy-efficient products, such as appliances and LED lighting, have improved energy efficiency throughout the state. Similar incentives have increased

participation in DR programs, such as SCE' s Summer Discount Plan, which gives customers a discount on their summer energy bills in exchange for allowing SCE to cycle the customer's air conditioning during peak load events. As new technologies are developed and deployed, and as time-variant prices become more common, SCE expects that participation in load shifting and load reducing programs will increase.

b) Information Transparency

Information transparency refers to the provision of information to customers, third parties, and other market participants to enable them to make informed decisions about energy usage that will result in positive impacts on energy demand and California's environmental goals. The foundational data elements that must be made available to customers and other authorized parties are customer usage information and electricity prices. The Smart Market is bolstered by the 15-minute and hourly usage data provided by smart meters and the varying cost of energy at the time it is used. This detailed, time-differentiated usage and cost information allows utilities to offer time-variant rate structures, such as those described above, as well as new and enhanced DR programs. The success of these rates and programs, however, is highly dependent upon customers' knowing their usage at a given time as well as the price of electricity at that time. Customers will be able to take action, or have home appliances and devices that can be programmed to take action, based on the cost of energy, or the real impact on the customer's energy bill, at a given time.

In addition to making usage and pricing data available to customers, the Smart Market will provide standards and protocols for making such information available in a consistent manner to third parties who can help customers with energy management. Because third parties will have more expertise with energy management than many customers, and because they will have established programs and services, more customers than would otherwise do so will likely participate in DR, DG, and conservation with the help of third parties.

c) Enabling Technology

Automated Metering Infrastructure (AMI) is the backbone solution for energy data for all customers. Open communication standards such as Smart Energy Profile (SEP) and OpenADR provide secure interoperability of devices across narrow and broadband networks. Other communications technologies can be integrated for load control where the AMI system provides usage data for customer event settlement. SEP standards adoption, anticipated in 2011, will enable myriad new products and services that can help accomplish the vision.

SCE is already working to offer key enabling technologies that will provide improved customer information about energy use and costs. These include: tools on the web, mobile applications, and

information devices in the home or business. SCE's smart grid will enable in-home devices, such as information displays, energy management systems, smart appliances, communicating thermostats, and other energy control equipment, that can work within the AMI network supplemented by other communications networks. The net result of the deployment of this enabling technology is that there will be increased participation in DR, DG, and conservation because customers will be better informed about their energy usage and costs and they will have solutions available, from SCE and third parties, to help them optimize their energy usage and bills.

2. Smart Customer

Smart Customers are customers who have a better understanding than traditional utility customers about their energy usage, its impact on the electric system, and related energy costs. The Smart Customer is empowered through both more information and new, enabling technology to act upon this information and improve his or her energy efficiency.

a) Informed

The Smart Customers that are essential for the smart grid to be successful must be better informed about their energy usage, energy costs, and the impact of their energy footprint on the electric system than most current customers. As described above, the Smart Market enabled by SCE's smart grid will allow customers to make choices based on access to real-time or near real-time information about both their energy usage and the cost of energy at a given time. SCE's smart grid deployment will also include time-variant pricing structures that more accurately reflect cost causation than many of today's flat rates. This information and associated price signals will convey to customers when the electric system is more strained. For example, a higher cost for electricity during an on-peak period will indicate to a customer that using energy at that time may place more pressure on the system because there is more system-wide demand at that time. It will also allow customers to optimize their energy usage for various purposes, including conservation or reduction of energy bills.

The smart grid will also enable SCE to keep customers better informed by leveraging multiple channels to deliver messages and information. SCE's vision for communication with Smart Customers includes the use of the internet, mobile devices, social networking, and in-home devices in conjunction with traditional channels such as mail, telephone, and mass media. By using all of these channels, SCE increases the likelihood that a customer will receive key messages about the smart grid and the benefits it enables.

b) Empowered

It is one step for customers to be informed about their energy usage and costs. To fulfill the goals of the smart grid, customers must also be empowered to act on that information to use energy more efficiently and, potentially, reduce their energy costs. Utilities and entrepreneurs focused on the smart grid space are currently developing many consumer products that will enhance – through automation and communication – customers' ability to act on energy information. These devices include, but are not limited to, in-home displays and energy management systems, smart appliances, and automatic load control devices. Smart Customers are further empowered to alter their energy usage and become active participants in the grid by time-variant pricing structures and incentives for participating in DG, DR, and EE programs.

An important aspect of empowering customers to manage their energy usage through enabling technology and increased information transparency is to ensure that customers' data privacy will not be compromised. In the course of enabling customers to better manage their power consumption, new types and increased quantities of data will be collected, retained, used, and, in some cases, exchanged among the utility, the customer, and third parties. The increase in the scale and scope of data, as well as the increase in the number of touch points, increases the quantity of risks and challenges in safeguarding customer data. SCE will take several measures to protect its customers' privacy as it deploys the smart grid. Most importantly, as it does today, SCE will abide by all laws and regulations related to consumer data privacy. This will include full compliance with the requirements that may be adopted in the forthcoming Decision Adopting Rules to Protect the Privacy and Security of the Electricity Usage Data of the Customers of Pacific Gas & Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company in the Smart Grid OIR.[36]

As directed in SB17 and R.08-12-009, SCE will leverage nationally adopted standards and protocols for the delivery of information to authorized third parties and for the transmission of information among customer and third party devices and utility smart devices. The use of standards for sending customer information minimizes the costs of these devices. Device manufacturers, utilities, and third party service providers can design their systems and products to leverage one standard rather than having to spend additional capital to accommodate varying protocols. Standards also promote innovation and competition among companies who develop energy management products and services because, by leveraging a nationally adopted standard, SCE will not promote or select a specific manufacturer or provider. Instead, SCE will make the necessary information available for all eligible and compliant products and services. To succeed in the marketplace, the device manufacturers will have to develop innovative solutions that

36 During the June 23, 2011 CPUC voting meeting, the Proposed Decision on Smart Grid Data Privacy and Security was held to the July 14, 2011 CPUC voting meeting. Thus, a final decision is likely in July 2011.

deliver value to customers rather than just having the advantage of a protocol selected by one or more utilities.

c) Able to use Electricity Efficiently

Primed by the Smart Market, SCE's Smart Customers will have the information and capabilities necessary to allow them, if they choose, to optimize their energy usage and save money on their energy bills. Smart Customers should have an abundance of options to use energy more efficiently and increase energy savings. These options range from manual action as a result of better and timelier information to elaborate energy management at premises incorporating automated DR, EE, DG, and energy storage. As stated in the CARB's *Climate Change Scoping Plan* pursuant to AB 32, "thinking about climate change and our carbon footprint will naturally become part of how individuals make decisions about travel, work, and recreation."[37] Bolstered by the Smart Market, SCE will give its customers the information, technology, and capabilities they need to use energy more efficiently.

d) Supporting Outreach and Education Activities

Recognizing that it serves multiple market segments, SCE has developed a marketing approach that takes these different market segments into account as it deploys smart grid related technologies, programs and tariffs.

One of the primary objectives of SCE's marketing efforts will be to increase the level of customer participation in DR programs. DR is not simply another load resource on par with generation, because there is a direct customer impact. It is SCE's investment in customers, through marketing, education and outreach (ME&O); customer choice; flexible program design; and enabling technologies that allow SCE to build and maintain this customer-provided resource. Therefore, SCE plans to enhance DR's value through its "customer-centric" vision.

SCE has and will continue to design cost-effective retail programs that encourage customer participation through a combination of customer-friendly designs, efficient ME&O, appropriate financial incentives, readily available energy usage information that informs customers' energy decisions, integration of enabling technologies and customer-centered energy solutions.

SCE views customer empowerment as a valuable asset to its business not only as a resource but also as an opportunity for its customers to benefit economically and support California's clean energy and GHG mitigation goals. Customers enrolled in DR programs can mitigate the inconvenience and dissatisfaction they may otherwise experience during firm load interruptions. Through price-responsive DR, customers

37 AB 32 Scoping Plan, p. 99.

may benefit directly by choosing to participate in load reduction opportunities and receive financial incentives for doing so. Further, SCE expects that many customers may elect to participate in its programs in an effort to support a healthier environment.

As discussed later in the document, SCE plans to grow its DR portfolio to nearly 1,900 MW by 2014. To support this level of growth, SCE plans to apply a strategic ME&O approach to educate customers about smart metering and, through ongoing customer engagement, encourage active participation in DR and dynamic pricing solutions. SCE's overall strategy for engaging customers in beneficial DR and dynamic pricing programs rests on a three-step cycle of:

1. Discovery
2. Activation
3. Participation

Once initial engagement is achieved, SCE then repeats the process, keeping customers involved by helping them continually learn about and adopt new energy saving methods and program offerings.

In line with this strategy, SCE plans to conduct an ME&O campaign designed to drive customer engagement in active energy management. By generating awareness and understanding, and by simplifying participation in programs and solutions, SCE will empower customers to use energy more wisely.

SCE will prepare customers to think, and most importantly, act differently with regards to their energy usage (by explaining concepts like Dynamic Pricing); motivate and incent them to take action by offering special rates and programs; and keep them engaged by helping them to optimize the benefits of participation. SCE will accomplish this continued involvement by giving customers access to new programs, and technology solutions that will help customers respond to events and ultimately change their energy consumption behavior.

Success will depend in large part on how well we help customers to become empowered to take control of their own power usage. A key component will be the extent to which SCE can market the programs in such a way that they are seen as additive by customers, and increase customer satisfaction.

3. Smart Utility

A smart utility is a utility that can safely and reliably accommodate clean, dynamic energy supply at various points on the electric system and facilitate flexible management of customer load to match actual conditions on the grid. A smart utility will install greater intelligence and automation throughout the grid – acquiring data at an order of magnitude larger and faster than the utilities of today – to better

manage critical assets, optimize system operations, and integrate renewable resources as well as PEVs. A smarter utility will develop new capabilities on top of a robust information technology platform equipped with pervasive interoperability and end-to-end cyber security. Ultimately, a smart utility is one that builds for the future and one that can continuously adapt to new customer demands, regulatory drivers, technological advancements and employee needs.

a) Reliable

A smart utility will enhance grid reliability and protection by building a network of interconnecting computers and devices that permit machine-to-machine interactions capable of dynamic management that could never have been achieved by man-to-machine interactions, simply because people cannot react as quickly as machines. SCE's smart grid vision includes deployment of responsive transmission and distribution devices capable of detecting precursors and mitigating grid-stability events before they cause problems, as well as quickly and automatically restoring service when such events are unavoidable. SCE will leverage its leadership in Phasor Measurement Unit (PMU) based technology to monitor the status and health of the grid at millisecond intervals, providing system operators and automated control systems with the situational awareness needed to identify and respond to conditions that can lead to catastrophic outages like the Northeast blackout of 2003.

On the distribution side, smart utilities will also deploy "self-healing" circuits that can quickly isolate fault-induced outages and limit the number of customers with service interruption. Advanced distribution management schemes will allow smart utilities to reroute power around overloaded circuits to avoid an outage. In cases where an outage is unavoidable or outside of utility control (i.e., storm, car runs into pole, etc.), the smart grid will help pinpoint the location of distress, so that field workers can be deployed as quickly and effectively as possible to minimize service interruptions. Overall, SCE's smart grid will provide greater monitoring and control across the entire power delivery system. This should enable quick and often automated response to outages or events of system instability.

b) Reduces its Environmental Footprint

Implementation of a smart grid will significantly reduce the total environmental footprint of SCE's electric generation and delivery system in several key areas: (1) integration of renewable resources and DG, (2) customer empowerment and enhanced load management capabilities, (3) grid optimization for more efficient power delivery, and (4) automation of operational activities.

By safely and reliably incorporating renewable generation at the transmission level, SCE will by 2020 provide one-third of its electricity from energy resources that emit zero carbon and no criteria pollutants. SCE's smart grid will not only allow higher penetrations of renewables, it will integrate clean technologies

– such as DR – to provide ancillary services and energy storage to balance renewable intermittency. Support of clean DG also reduces carbon and criteria pollutants, while its proximity to customer load reduces line losses and associated GHGs.

Beyond enabling a cleaner generation portfolio, SCE's smart grid will also help customers to better manage their energy use and to conserve energy. Provision of more granular energy consumption data in near real-time will enable customers to conserve electricity and reduce their environmental impact. AMI-enabled dynamic pricing and load control functionalities will reduce utilization of inefficient peak generators, which typically have a greater emissions factor and a higher operating cost. Like DG, enabling DR and energy conservation accrues greater GHG reduction by avoiding system losses as well as generator inefficiency. By far the cleanest kWh is one that was never produced in the first place. To that extent, advanced volt/VAR control and grid management capabilities will allow SCE to optimize the provision of electricity—though end-to-end coordination of transmission and distribution field devices—thus minimizing system losses and reducing associated GHGs.

c) Enables Environmental Policy Goals

SCE's smart grid vision is largely shaped by California's progressive environmental policies. First and foremost, the smart grid's ability to integrate renewables while maintaining power quality and reliability will allow SCE to meet the 20 percent by 2010 Renewables Portfolio Standard ("RPS") requirements established in SB 1078 and SB 107, as well as the 33 percent by 2020 RPS requirement first established by Executive Order S-21-09 and recently codified into law through SB 2X.

Smart utilities should integrate distributed energy resources to support:

- Achievement of California's GHG reduction goals and OTC regulation by providing electricity close to the load center.
- 3,000 MWs of solar generation by 2017 through the state's Go Solar California! campaign.
- Up to 500 MWs of distributed renewables through feed-in tariffs required by SB 380 and AB 1969.
- Distributed wind turbines and fuel cell technologies incentivized by the state-wide Self Generation Incentive Program.
- Up to 500 MWs of utility and 3rd party owned solar PV under the SPVP in accordance with D. 09-06-049 and Resolution E-4299.
- The Commission's Big Bold Strategies for Energy Efficiency—namely the call to have all new residential and commercial construction be Zero Net Energy by 2020 and 2030 respectively.[38]

38 Programmatic Incorporation of ZNE required by D. 07-10-032 and D. 07-12-051.

- Smart integration of PEVs that will help maximize the environmental benefits of electricity as a transportation fuel and enable a full suite of environmental policies, including:
    - AB 1493 Vehicle tailpipe CO2 emission standards;
    - Zero Emission Vehicle regulation;
    - Executive Order S-01-07 - Low Carbon Fuel Standard;
    - Corporate Average Fuel Economy (CAFE);
    - EPA Renewable Fuel Standards;
    - U.S. EPA new endangerment finding on greenhouse gases;
    - U.S. EPA new ambient air quality standards for PM 2.5; and
    - U.S. EPA proposed lowering of ozone standards.

d) Creates an Open Platform

SCE's smart grid vision enables maximum third party access to the grid through the integration of alternative generation resources and participation of customer load and demand-side technologies in grid and/or market operations. At the transmission level, SCE's smart grid will accommodate a broad spectrum of bulk renewable technologies, such as wind and solar power, enabling independent power producers to interconnect renewable generation facilities throughout the West. At the distribution level, SCE's smart grid will provide customers, utilities, and third parties the opportunity to interconnect solar panels, micro wind turbines, CHP units and fuel cells. SCE's smart grid will also support deployment of energy storage in various applications across the grid, enabling innovative ownership models that provide maximum benefit through new power services, grid support, and infrastructure replacement.

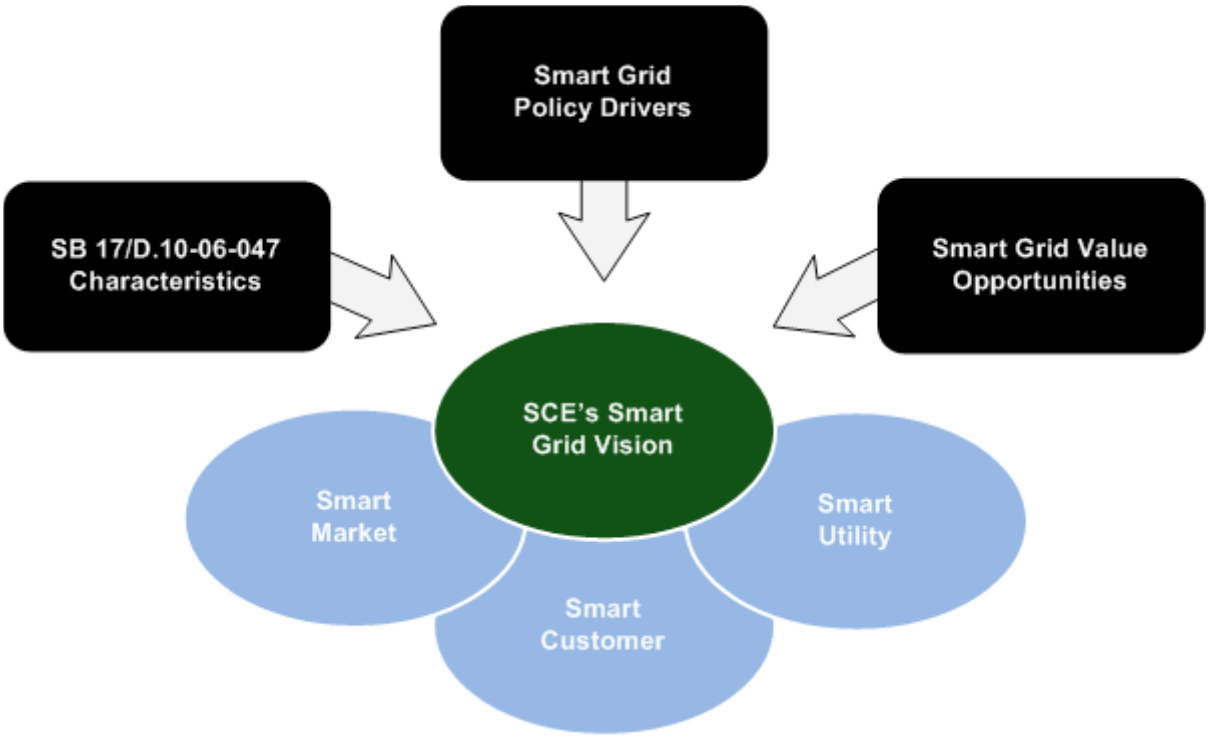
SCE's plans would open the grid to third party participation. For example, the integration of DR into CAISO wholesale markets will allow customers and appropriate third party aggregators to participate directly in day-to-day operation of the grid. Also, advanced communication with PEVs may one day allow customers or third parties access to the grid through utilization of their car as an energy resource.

Overall, SCE envisions developing a grid that supports interoperability and open access. This should create a safe, reliable platform that fosters incorporation of technology or service-oriented innovations by third parties.

C. Summary / Conclusion

Figure 7 below summarizes the elements of SCE's smart grid vision. This vision reflects the smart grid characteristics that the Commission identified and adopted in D. 10-06-047. Our vision is also informed by specific policies adopted in California as well as specific opportunities where smart grid technologies can help SCE deliver value to its customers. Finally, this vision is supported by the roles of three key stakeholders in the smart grid: the smart market, the smart customer and the smart utility.

Figure 7 – SCE's Smart Grid Vision

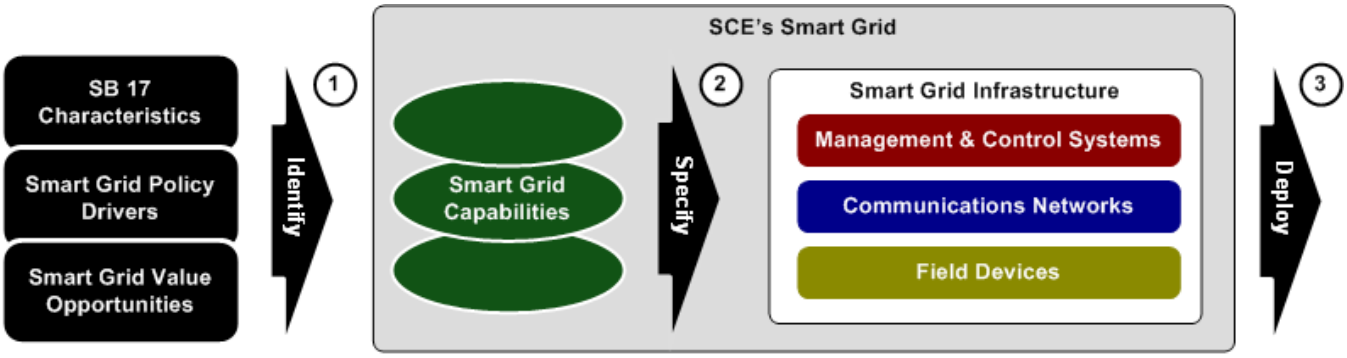


IV. Smart Grid Strategy

In Chapter III above, SCE presented its vision of a smart grid that reflects a variety of characteristics, policy drivers and opportunities to deliver value. This chapter will present SCE's strategy for turning that vision into a reality.

SCE views its smart grid in terms of two elements: capabilities and infrastructure. Smart grid capabilities represent SCE's ability to operate in a certain manner or provide a set of functions. To enable these capabilities, SCE has to invest in and leverage certain infrastructure.

Figure 8 – SCE's Smart Grid Strategy



The first step in SCE's smart grid strategy involves identifying the key smart grid capabilities that it should develop. Smart grid capabilities should reflect the characteristics described in SB 17 and adopted by the Commission in D.10-06-047. The capabilities should also allow SCE to (1) meet one or more of the policy goals described in Section III.A.2 above and/or (2) take advantage of one or more of the value opportunities described in Section III.A.3 above.

The second step in SCE's smart grid strategy involves determining what smart grid infrastructure it needs to enable the smart grid capabilities identified in step 1. In general, to perform each capability, SCE will have to invest in three types of infrastructure. First, SCE will have to deploy various type of communicating field devices that are capable of either gathering data about system conditions, controlling a piece of equipment or displaying information to field personnel or customers. Second, SCE will have to deploy communication networks over which these field devices can send information to and receive instructions from SCE's back office systems. Third, SCE will have to invest in data management and control systems that can process data received from, or send instructions to, communicating field devices.

The third step in SCE's smart grid strategy involves determining when the infrastructure identified in step 2 is ready for deployment. The infrastructure required to enable SCE's smart grid capabilities includes both "platform" infrastructure elements that SCE deploys in the course of executing its core utility functions, as well as infrastructure that will serve unique requirements of particular smart grid capabilities. SCE

distinguishes between platform and capability-specific infrastructure in determining how and when to deploy technology. SCE's smart grid strategy includes guidelines that allow SCE to determine when each type of infrastructure should be deployed in a way that meets smart grid capability needs in a cost effective manner.

In summary, SCE's smart grid strategy, depicted in Figure 8 above, includes the following steps:

1. Identify key smart grid capabilities based on CPUC-adopted smart grid characteristics and key policy and value drivers;
2. Determine infrastructure requirements for each capability; and
3. Assess the deployment-readiness of this required smart grid infrastructure.

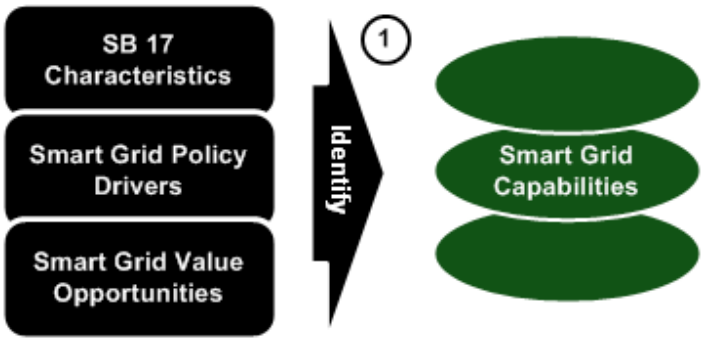
SCE's presentation of its smart grid strategy in this chapter follows these steps. Part A describes SCE's decision-making framework for identifying key smart grid capabilities. Part B describes SCE's approach to determining what infrastructure it will need to deliver each capability. Finally, Part C describes SCE's strategy for determining when smart grid infrastructure is ready for deployment.

The smart grid strategy presented in this chapter is meant to guide construction of SCE's smart grid roadmap. This chapter presents the approach SCE takes in making decisions about smart grid investments. The Deployment Baseline and Smart Grid Roadmap chapter that follows describes a plan for SCE's smart grid investments based on this strategic approach.

A. Identify Key Smart Grid Capabilities

The first step in developing SCE's smart grid strategy is to identify key capabilities that will allow it to meet the smart grid drivers described in the Vision Chapter. Specifically, these capabilities should (1) align with smart grid characteristics adopted in SB 17 and summarized by the CPUC in D. 10-06-047, (2) enable specific policy goals that SCE views as critical in the near-term, and/or (3) present the opportunity to deliver customer value.

Figure 9 – Smart Grid Strategy Step 1: Identify Key Smart Grid Capabilities



Given the large number and wide variety of smart grid drivers identified in the Vision chapter, the process of identifying smart grid capabilities that optimize against these goals is challenging. SCE believes that the smart grid capabilities presented in this document are the appropriate basis for its smart grid strategy, because these capabilities meet the following criteria:

1. Each capability specifically addresses at least one of the eleven areas listed in Section 3.3 of D. 10-06-047;

and

2. The capabilities taken together collectively address all of the eleven areas listed in Section 3.3 of D. 10-06-047. As these eleven areas were designed to summarize the goals of SB 17,[39] criteria 1 and 2 confirm alignment of SCE's smart grid efforts with that legislation;

and

3. Each capability: (a) specifically addresses a particular policy goal identified in the Vision chapter, and/or (b) specifically addresses a particular value driver identified in the Vision chapter. These criteria will help ensure that SCE's smart grid efforts deliver customer benefits in the form of either compliance with relevant policies or more direct customer benefits.

This framework validates that SCE's smart grid efforts specifically address each of the eleven areas listed in Section 3.3 of D. 10-06-047, and demonstrates that its smart grid investments should deliver benefits to its customers. In the Deployment Baseline and Smart Grid Roadmap chapter, SCE will identify each of its prioritized smart grid capabilities and demonstrate their compliance with the criteria described above.

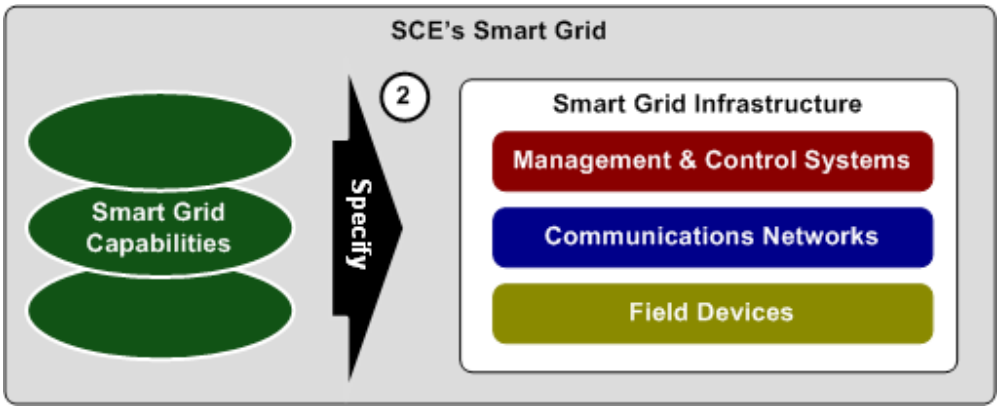
B. Determine Infrastructure Requirements

The next phase of the company's smart grid strategy is specifying the enabling infrastructure needed to successfully deliver the capabilities identified above.

To achieve each capability identified through the framework described in Section IV.A, SCE will deploy infrastructure in the form of management and control systems, communications networks and field devices. SCE considers several factors, and uses a variety of tools in specifying and designing the infrastructure that will support each capability. These considerations are described in more detail below.

39 Assigned Commissioner and Administrative Law Judge's Joint Ruling Amending Scoping Memo and Inviting Comments on Proposed Policies and Findings Pertaining to the Smart Grid (February 8, 2010), pp. 12-13.

Figure 10 – Smart Grid Strategy Step 2: Specify Enabling Infrastructure Requirements



1. Focus on Capability-Based Requirements

SCE's approach to investing in smart grid infrastructure starts with determining the needs of the capabilities this infrastructure must enable. Each of the smart grid capabilities that SCE has prioritized based on the framework in Section IV.A will dictate particular types of energy and information technology, and will impose specific performance requirements for this equipment. Identifying these requirements through comprehensive analysis and planning is a critical step in SCE's smart grid deployment strategy.

Use cases are one tool that SCE uses in determining what requirements infrastructure must meet to serve a specific capability. In developing use cases, SCE generates and documents requirement sets for smart grid technologies. Use cases accomplish this by focusing on business scenarios that identify the people, field technologies, and information systems that must interact to achieve a specified capability. SCE successfully utilized use cases in its approach to identifying business needs and developing systems requirements for its smart metering program, known as Edison SmartConnect™ (SmartConnect). SCE partnered with the Electric Power Research Institute (EPRI) to use the Inteligrid Use Case framework as the starting point for SCE's independent development of use cases. EPRI then translated the SCE use cases back into the Inteligrid repository for industry use.[40]

SCE's capability-focused approach helps it make investments that best serve its customers. Areas undergoing rapid advances in technology performance often risk pursuing "solutions looking for problems". In some cases, advocates for promising technologies may support investment in that technology before its value is completely understood. SCE's focus on determining the infrastructure needs of capabilities that reflect its operational objectives can help avoid falling into this trap.

40 SCE's SmartConnect use cases are available at www.sce.com/usecases.

2. Identify Platform Infrastructure

Many of SCE's smart grid capabilities will be enabled by infrastructure elements used by SCE to serve its core, "non-smart" utility functions. For example, a distribution management system (DMS) is a management and control system that most utilities use to manage their distribution grids. While investment in a DMS is part of SCE's core business of providing reliable electrical service, SCE will also leverage its DMS to deliver several smart grid capabilities.

As part of its smart grid strategy, SCE identifies common, or "platform", infrastructure that is required to serve smart grid capabilities, but is also required as part of its basic provision of utility service. Identifying platform infrastructure allows SCE to leverage existing infrastructure where possible and design platforms to support all smart grid and non-smart grid capabilities. Doing so allows SCE to avoid costs associated with redundancy and system integration in the future.

3. Leverage Interoperability Standards

SCE defines "interoperability" as a characteristic that permits seamless communication and exchange of information between diverse, disparate systems provided by different vendors. Utility grids will need interoperability of key future smart grid technology components to support a robust, flexible, and secure energy infrastructure. SCE's vision for a smart grid has long been premised on the idea of "interoperability from the generator to the customer, and everywhere in between." This is important for stimulating vendor competition, fostering innovation, and realizing lower costs.

Interoperability is essential for future smart grid deployments and enhancements to mesh with existing capital investments. The challenge is developing a systems architecture and roadmap that provides a graceful transition from the existing systems to the future state. Computing systems and telecommunications have evolved over the past 25 years to the mostly plug-and-play state that we know today. SCE expects the smart grid to similarly evolve over the next two decades, given the typically long asset lives and the need to balance large capital costs with consumer rate impacts.

As the grid evolves and becomes "smarter" and more capable over time, standards must also evolve to support higher degrees of interoperability and security, and to enable more advanced capabilities. When the concept of smart grid evolution is applied in the area of standards adoption, the implication is that at any point in time the industry will be characterized by a mix of old technology (or no technology at all), last-generation smart technology, current-generation smart technology, and "greenfield" technology opportunities, all of which must function together in an integrated manner. Also, given that many smart grid technology lifecycles are much shorter than a typical utility regulatory-to-deployment cycle, it is very likely that the grid will continuously evolve to the degree by which intelligence is both incorporated

and leveraged. Smart grid interoperability standards will be critical in helping to bridge the gap between different generations of technologies and in supporting a gradual, multi-step transition to the smart grid vision.

To support the development and promulgation of interoperability standards for smart grid deployments, SCE has been active over the past five years in several DOE-sponsored efforts, including the GridWise Architecture Council to define use cases, user requirements, and reference designs. Over the past two years, SCE has been increasingly active in the National Institute of Science and Technology's (NIST's) efforts to identify and recommend standards for the smart grid. SCE's long-standing participation with several industry and standards organizations provided an opportunity to work more closely with both the Department of Energy DOE and NIST on developing standards in several areas, including customer access to energy information and a set of smart grid cyber security specifications and profiles.

Smart Grid interoperability can only be achieved through extensive participation by utilities to communicate capability and performance requirements as inputs to standards that are detailed enough to provide for certification by an accredited testing facility. Utilities can then procure certified products from competing vendors that work together, and vendors have incentive to develop increasingly interoperable and secure products to gain market share.

a) Standards Must Address Privacy Needs

Another set of key considerations in SCE's determination of smart grid infrastructure requirements are the privacy implications for SCE's customers when we deploy smart grid infrastructure. Many of the smart grid capabilities and related infrastructure that SCE is evaluating involve producing and communicating customer data. Protecting this data is paramount for SCE. Standards are one of the key tools SCE uses to ensure its smart grid deployments incorporate adequate privacy protections.

SCE is heavily involved in standards development at the national and international level across the full range of smart grid applications. SCE's approach to evaluating the impact of any particular standard on privacy is to understand, at a very basic technical level, the key points of interoperability to which a standard should be applied, the data contained within the interfaces, the parties involved in the information exchange (i.e. customer, utility, third party, etc.) and the security/privacy mechanisms specified by the standard (i.e. confidentiality,. encryption, authentication, authorization, etc.). Once the standard is reasonably well understood at a technical level, SCE evaluates the security and privacy risks to the data at rest and in transit in the context of the threat environment in which the interfaces operate.

If a standard does not address security and privacy concerns directly, and refers to another standard for guidance, then the technical practicality of applying the referenced standard is evaluated. Feedback is either provided to the standards workgroup or guidance is provided to the project or program

implementing the standard. Supporting policies and procedures are also evaluated and updated when a smart grid related project is implemented.

Additionally, SCE is engaged in the DOE's ASAP-SG program to develop security profiles that provide guidance on how to apply standards in product development and smart grid implementation projects to ensure interoperability, security and privacy are maintained. Lastly, privacy and security standards are only as good as their implementation. As such, SCE conducts vulnerability analysis, threat and risk assessments and penetration tests on designs, products and system solutions to ensure the standards are properly implemented.

b) Making Investments while Standards are Evolving

A self-sustaining smart grid market based on interoperability standards and coupled with device upgradability is the most cost-effective and reliable way to minimize the risk of stranded costs, but there are circumstances like the timing of policy drivers that require investments ahead of the standards process. When deployment is required before a certified standard is available, key decisions must be made about whether to attempt to accelerate the standard, wait for completion, deploy with an upgrade strategy, or ignore the standard and opt for a proprietary solution.

Performance requirements, technical constraints, schedule and costs are factors in this decision-making process. Depending on the magnitude of the impact of the standard on the implementation, SCE may engage externally to accelerate the market by leading a key standard development effort. Additionally, SCE evaluates options such as upgrade strategies and gateway approaches as a means to continue deployment without waiting for a standard to be certified. Requiring standards-based products, upgradability and performance criteria in a solution are critical to maintaining flexibility as standards evolve over time.

Many standards related to customer energy management are currently evolving. OpenADR is a standard developed to support commercial energy applications using broadband technologies. It is technically feasible to use OpenADR via the internet to communicate with a customer's Wi-fi connected devices. However, because OpenADR typically supports commercial customer applications, the message sizes for which it is designed are large. Transmitting these messages across a ZigBee / Smart Energy Profile (SEP) network would be inefficient. Hence, information from SCE's SmartConnect meter would need to connect to the customer's Wi-fi network through a gateway device capable of translating the SEP messages over ZigBee protocol from SmartConnect meters into OpenADR over Wi-fi. In fact, a more sophisticated gateway could even support a variety of combinations of protocol translations (such as SEP1.0 to SEP 2.0 to OpenADR to other standards or proprietary schemas running over Wi-fi, ZigBee, Homeplug or other), providing the customer with upgrade flexibility from multiple parties on multiple communication channels. To date, we have not seen any OpenADR to SEP gateways. The cost and market feasibility is unknown. Hence, a determination of cost-effectiveness is infeasible at this time.

4. Evaluation of Existing Communications Infrastructure

Smart grid stakeholders have expressed an interest in leveraging existing commercial communications networks to achieve the desired network coverage for smart grid capabilities at the lowest cost. The viability of commercial networks as a communications solution for smart grid capabilities will vary based on the particular needs of a given capability. Commercial wireless technologies have varying coverage, availability, latency, and security characteristics that may limit the types of applications for which they are suitable. Therefore, commercial wireless technologies must be evaluated with knowledge of their varying capabilities and weaknesses in all plausible conditions of operation. Commercial wireless networks, in many cases, were not designed to meet the utilities' reliability, latency and stringent security requirements. As a result, the networks may not perform well for critical smart grid applications.

Smart grid capabilities require a range of two-way data communication networks that connect the generation-to-customer electric system with service providers, system operators and markets. These communications networks must also support capabilities that monitor and manage the flow of electricity across the transmission and distribution system and its consumption at customer premises. Smart grid communications networks therefore serve both monolithic features like generating power plants and much more diverse network architectures at the level of the distribution system, office or home. In addition, the smart grid capabilities that these networks must support vary widely in their needs regarding bandwidth, latency, reliability and security.

Such a diverse set of data networks connecting and supporting all of the domains and capabilities of a comprehensive smart grid can utilize most network technologies: wired and wireless (using both unlicensed and licensed spectrum) as well as carrier-owned and utility-owned networks. Each network class has an important role to play in the smart grid, and each class is associated with certain benefits and challenges. Wired backbone can have greater bandwidth, but appears to be much more expensive to build than wireless backbone. Utility-owned licensed wireless provides more coverage flexibility (i.e., to locate transmitters for remote areas or the ability to boost radio power) compared to unlicensed public wireless networks. However, building, owning, operating and maintaining licensed infrastructure requires a high degree of telecom expertise and large capital investment. Given the range of qualities that these technologies bring to a network, and the diversity of smart grid communication needs, the specific communication requirements of a given smart grid application should drive the selection of the communications technology used to support that capability.

In certain cases, SCE does and will continue to use commercial networks. Commercial networks will provide backhaul for the approximately 5 million SmartConnect meters that SCE will deploy by 2012. For other needs, current commercial communications networks may be adequate for deploying some smart grid capabilities in metropolitan areas, but may not be adequate for rural and sparsely populated areas

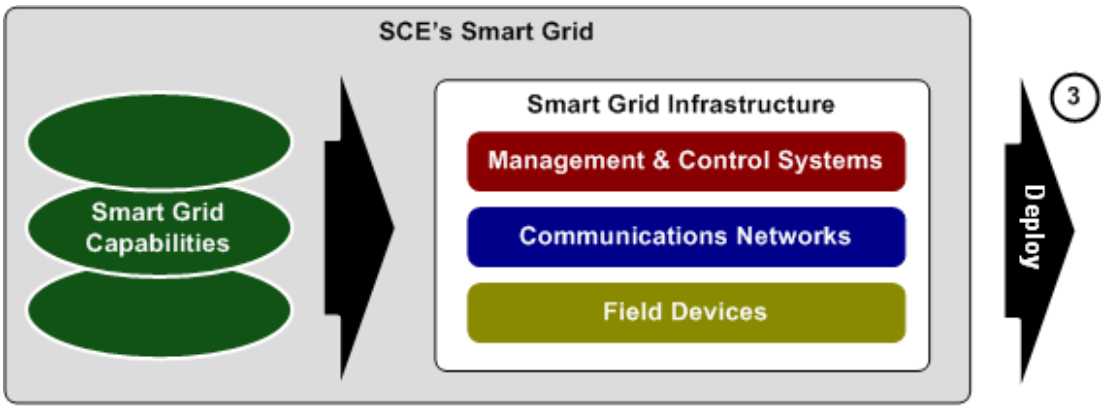
due to lack of coverage. In addition to coverage issues, the security and reliability of these networks must be analyzed and designed to meet the particular smart grid capability requirements. The monitoring and control of large generation plants, the transmission and distribution systems, and major substations would all be considered critical smart grid systems and would require the highest security and reliability. Commercial communication systems are not recommended for these applications. For routine monitoring of small, dispersed DG, and meter reading, commercial communication networks may be acceptable.

Consistent with SCE's broader approach to determining what infrastructure can serve its smart grid needs, the viability of commercial networks will depend on the specific requirements of the smart grid capability that network will serve. The communications needs of each of SCE's smart grid capabilities are described in the Deployment Baseline and Smart Grid Roadmap chapter below.

C. Assess Deployment Readiness

The final step in SCE's smart grid strategy involves determining how and when to deploy the infrastructure specified by the considerations above. First and foremost, SCE has adopted a systematic research, development and demonstration (RD&D) process for many new technologies that it plans to deploy. Based on the results of this process, SCE then makes determinations about the appropriateness of platform and capability-specific deployments based on a variety of factors. The sections below describe SCE's RD&D efforts as well as the factors that inform SCE's platform and capability-specific deployment decisions.

Figure 11 – Smart Grid Strategy Step 3: Assess Deployment Readiness



1. Research, Develop, Demonstrate, Deploy

SCE is widely recognized in the electric utility industry as a leader in evaluating, adopting and implementing advanced technology. SCE has achieved this leadership position by creating a rigorous and repeatable technology evaluation and testing process. SCE's technology evaluation approach follows industry testing standards developed by, among others, the Institute of Electrical and Electronics Engineers (IEEE) and the International Organization for Standardization (ISO).

To successfully develop and implement smart grid RD&D activities, SCE formed its Advanced Technology organization by pooling existing resources from throughout the company. SCE centralized these resources to efficiently focus and integrate disparate efforts in advancing technology evaluation and use. This centralization also enabled SCE to coordinate efforts on key principles such as standards for smart grid technologies or cyber security with external stakeholders, including the CPUC and the CEC. Finally, SCE's Advanced Technology organization allows it to better manage response to and cooperation with policy and regulatory direction from regulators and legislators on key advanced technologies.

The Advanced Technology group has strengthened SCE's leadership role in smart grid development and reinforced SCE's partnerships with regulatory bodies, governmental agencies, and industry leaders. These efforts assist in establishing sound policies and standards to support smart grid development and integration. They have also helped bring federal funding to California to support smart grid development. Through Advanced Technology's efforts, SCE was successful in securing ARRA funding for two demonstration projects. These projects include the Tehachapi Storage Project, a utility-scale energy storage project utilizing automotive-grade batteries. The ARRA projects also include a regional smart grid demonstration in Irvine, California that encompasses the development of a secure energy network for the smart grid.

2. Build Smart Grid Capability Requirements into Platform Infrastructure

As discussed above, to enable its smart grid capabilities, SCE will need to leverage many devices, networks and systems that SCE deploys as part of its core provision of utility service. SCE views these infrastructure elements as platform investments. Because this infrastructure enables conventional utility functions as well as smart grid capabilities (i.e., SCE would make these investments even if it were not pursuing smart grid capabilities), a variety of considerations beyond the needs of smart grid capabilities inform the timing and nature of deploying this infrastructure. SCE's holistic capability-based framework allows it to identify platform infrastructure that will eventually lead to smart grid capabilities and build necessary requirements into periodic upgrades and refreshes of this infrastructure when they occur. This design approach helps SCE avoid making single-purpose and duplicative investments that create unnecessary integration costs as smart grid systems converge and interact in the future.

3. Make Cost-Effective Incremental Investments

A given infrastructure element's cost-effectiveness depends on several factors. Each of SCE's smart grid capabilities lends itself to a distinct method for evaluating the deployment readiness of its supporting infrastructure. For example, SCE is pursuing the Wide-Area Monitoring, Protection and Control (WAMPAC) capability so that it can safely and reliably operate the bulk power system as a variety of energy policies increase the complexity of executing this core utility function. SCE will therefore assess the appropriateness of deploying WAMPAC-enabling infrastructure based on technology maturity and how well a potential deployment addresses the challenges created by relevant policies.

Other capabilities dictate different approaches. For instance, the Advanced Volt/VAR Control capability allows SCE to reduce line losses and achieve energy savings by better managing voltage levels on distribution circuits. SCE will therefore evaluate the deployment readiness of infrastructure that enables Advanced Volt/VAR Control by evaluating technology maturity and comparing the costs of the deployments to the benefits associated with potential energy savings. Organizing its smart grid strategy around well-defined capabilities will provide SCE a clear analytical framework for determining when to deploy certain smart grid technologies to best meet policy objectives and/or deliver value.

4. Compliance with GO 156

Finally, in making procurement decisions about smart grid technologies, SCE consistently looks to further the goals of General Order 156, which promotes the participation of women, minority and disabled veteran business enterprises (WMDVBEs) in procurement of contracts from California's utilities.[41]

SCE's Supplier Development and Diversity group has implemented a Spend Category engagement model that collects supplier information about projects, including smart grid projects, across SCE. This tool helps us identify areas of WMDVBE underutilization and aids in uncovering opportunities for targeted outreach and development. Another tool, SCE's Supplier University, supports the development of small and diverse suppliers so that they can compete at the level required to bid on SCE projects and programs.

SCE's Supply Management bidding process takes into account the WMDVBE status and subcontracting plans of each bidder and SCE considers these factors in its evaluation process. In cases where SCE contracts with a non-WMDVBE prime for a smart grid or other program, SCE's new subcontracting program tool supports accurate and timely reporting of information about subcontracted WMDVBE spending. The Procurement and Supplier Diversity department monitors this data to ensure performance.

41 *See* CPUC General Order 156, Rules Governing the Development Of Programs to Increase Participation Of Women, Minority and Disabled Veteran Business Enterprises in Procurement of Contracts from Utilities as Required by Public Utilities Code Sections 8281-8286, available at http://162.15.7.24/PUBLISHED/GENERAL_ORDER/59939.htm.

V. Deployment Baseline and Smart Grid Roadmap

In the Vision Chapter above, SCE presented its vision for a smart grid that reflects certain characteristics adopted by the Commission in D. 10-06-047 as well as specific policy drivers and value opportunities that a smart grid can help address. In the Strategy Chapter, SCE described its methodology for identifying capabilities, specifying infrastructure and determining the deployment readiness of platform and capability-specific infrastructure to help SCE move towards its smart grid vision. In this Deployment Baseline and Smart Grid Roadmap chapter, SCE translates the strategy guidance provided above into a depiction of its future plans for deploying smart grid infrastructure through 2020, and its progress to date in doing so.

This chapter is organized around the eleven smart grid capabilities that SCE has selected as focus areas because they: (1) are aligned with smart grid characteristics adopted in SB 17 and summarized by the CPUC in D. 10-06-047; (2) enable specific policy goals that SCE views as critical in the near-term; and/or (3) present the opportunity to deliver substantial customer value. SCE has further organized these capabilities into four domains aligned with the physical organization of the electric grid. SCE's eleven smart grid capabilities and related domains are depicted in Figure 12 on the next page.

In the sections that follow, for the capabilities in each domain, SCE describes: (1) its rationale for focusing on that capability; (2) the infrastructure required to deliver that capability in the future; and (3) SCE's current progress and future plans for deploying that infrastructure.

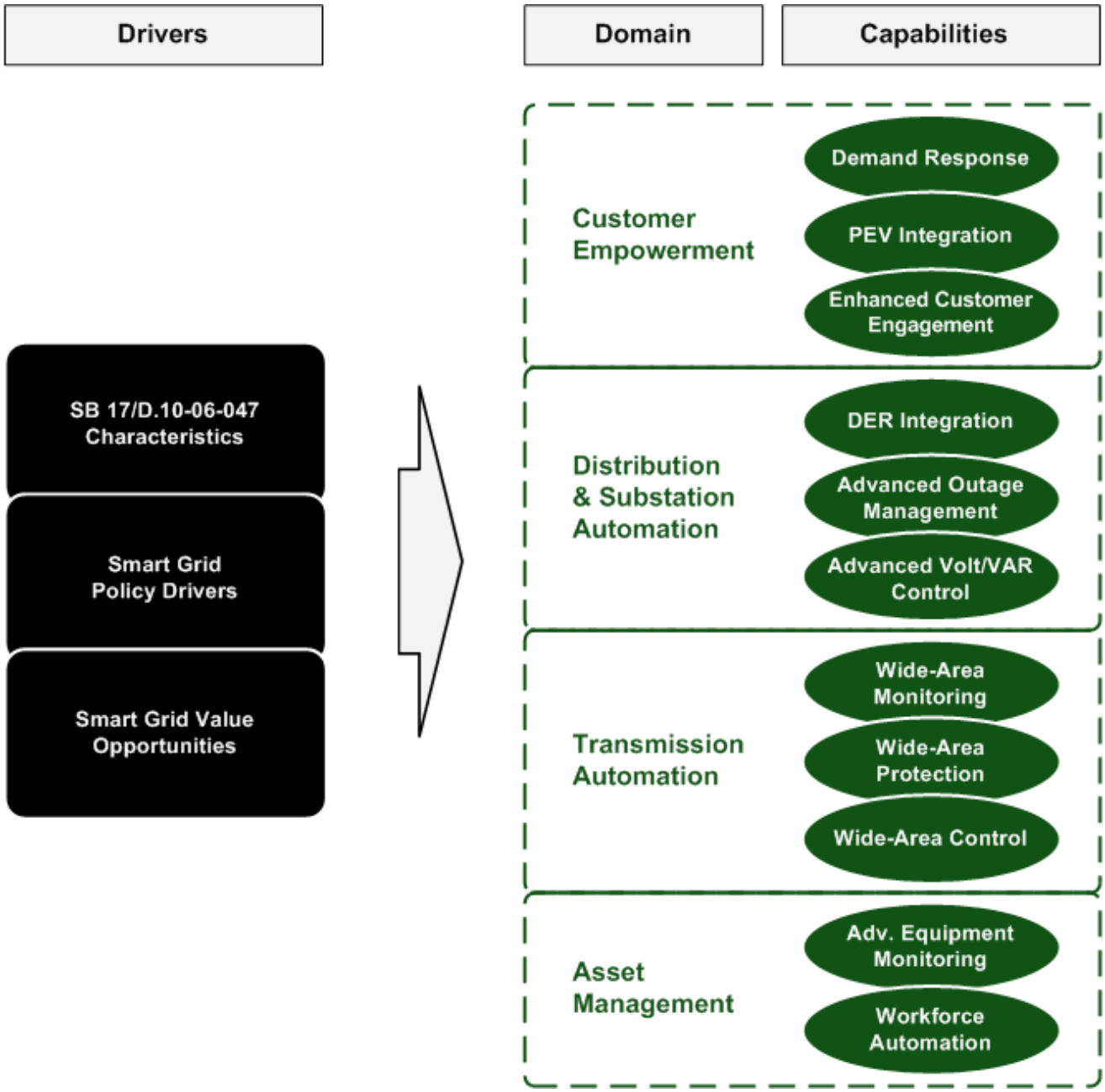
Parts A through D define each of the smart grid capabilities above and explicitly link each one to the smart grid characteristics and goals identified in SB 17 and adopted by the Commission in D. 10-06-047. Each capability also maps directly to one or more of the policy and value drivers identified in the Vision chapter.

SCE then describes, at a high level, the types of infrastructure that it will ultimately deploy to enable each capability. These infrastructure elements include management and control systems, communications networks and field devices that must work together for SCE to achieve a given capability.

As noted in the Strategy chapter above, SCE has identified several infrastructure elements that will be required to enable smart grid capabilities as "platform" infrastructure because they serve non-smart and smart grid functions. After identifying the full range of infrastructure required to enable SCE's smart grid capabilities in Parts A-D, Part E summarizes SCE's baseline and roadmap for these platform investments.

Finally, Parts F through I present qualitative and quantitative data to describe a baseline of SCE's current progress (as of December 31, 2010) towards delivering each capability and deploying the infrastructure required to do so. Parts F through I then describe, based on principles laid out in the Smart Grid Strategy chapter, SCE's plans to deploy additional infrastructure for each capability.

Figure 12 – SCE's Smart Grid Capabilities



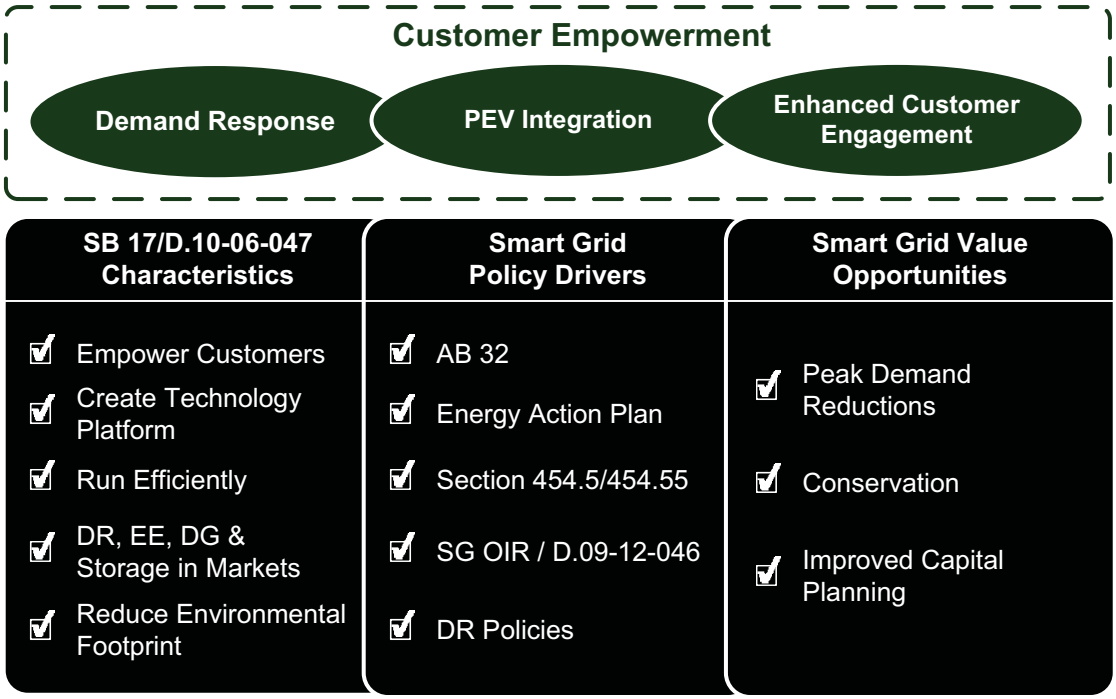
These planned infrastructure deployments are organized into deployment projects, which are in turn grouped into the following categories to reflect SCE's level of certainty about and the readiness for deployment of the underlying infrastructure:

1. Approved – The Commission has already authorized funding for these projects and deployment will continue through part of the period covered by the Deployment Plan.
2. Proposed – SCE has proposed these projects in applications pending before the Commission.
3. Forecast – These projects represent continuations of deployment activities in either approved or proposed projects beyond the periods for which they have received Commission approval or been proposed. Most of these projects start in 2015 or after.
4. Conceptual – These projects include existing technologies where the scope of future deployments is uncertain, as well as technologies that SCE does not think are currently deployment-ready.

A. Customer Empowerment Capabilities

In the Customer Empowerment domain, SCE focuses on three capabilities – DR, Enhanced Customer Engagement, and PEV Integration – that will empower customers to take a more active role in managing their energy consumption. The sections below describe each of these capabilities and their related drivers in more detail.

Figure 13 – Customer Empowerment Capability Drivers



1. Demand Response

DR is a dynamic interaction between SCE and its participating customers in which a customer can earn incentive payments or avoid increased costs by reducing their usage in response to certain system or market conditions. SCE delivers its DR capability through a portfolio of programs that encourage customers to decrease their usage, typically during system peaks, either by manually choosing to do so or through the use of equipment that automates the reduction. Through its DR offerings, SCE seeks to lower wholesale and customer costs and increase electricity system reliability by stabilizing demand over time, reducing demand when supply is low, and setting rates that more accurately reflect the marginal cost of providing electricity.

By reducing peak demand, DR offers value opportunities in the form of deferred procurement of generation capacity and avoided energy procurement during times of high wholesale market prices—both of which are costs ultimately passed on to customers. Because the demand for electricity reaches its highest levels only a few days or hours each year, SCE must procure enough generation and build transmission and distribution assets to reliably serve peak demand even though average usage is much lower. Also, during periods of high demand, the marginal cost of electricity increases because less efficient generation units have to be brought online to serve increasing customer load. SCE can therefore minimize these energy and capacity procurement costs by reducing customer load when the demand for, and cost of, electricity is highest. DR programs can be and have been used to reduce load and mitigate local distribution and transmission constraints. For example, on numerous occasions, SCE has activated its Summer Discount Plan in areas where substation transformers were nearing overload, thereby avoiding a potentially prolonged widespread service outage.

In addition to the reliability and peak demand reduction benefits described above, SCE's DR capabilities support several policy goals and are aligned with smart grid characteristics identified in SB 17 and D. 10-06-047. As noted in Section III.A.2, California's Long Term Energy Efficiency Strategic Plan, Updated Energy Action Plan, and Public Utility Code Section 454.5 all encourage the state's utilities to pursue some combination of DR, dynamic pricing and TOU rate programs as tools to meet AB 32 GHG reduction goals. In conjunction with policies established in the DR OIR, SCE's DR portfolio will be increasingly comprised of dynamic pricing rates and price-responsive programs as opposed to emergency triggered programs used for system reliability. SCE's DR capability will provide more granular or specific locational dispatch of DR resources as well as the telemetry requirements needed to fully integrate these programs into CAISO wholesale markets. The move towards market integration will allow DR resources to be bid against conventional generators and provide ancillary services.

With respect to SB 17 and D. 10-06-047 smart grid characteristics, DR "motivate[s] consumers to actively participate in operations of the grid"[42] by engaging them through rates that reflect the true cost of power. The capability also promotes a grid that "run[s] more efficiently"[43] by minimizing on-peak power production. Finally, several specific DR programs "support the sale of DR, energy efficiency, distributed generation, and storage into energy markets,"[44] while reducing the use of on-peak power helps to "significantly reduce the total environmental footprint of the current electric generation and delivery system in California."[45]

2. Plug-in Electric Vehicle Integration

SCE's PEV Integration capability will allow it to provide a seamless experience for customers who chose to buy PEVs while safely and cost-effectively integrating vehicle charging with grid operations.

As discussed in Section III.A.2.e), a variety of state and federal policies as well as customer preferences are likely to drive adoption of PEVs by SCE's customers over the next 10 years. As customer adoption of PEVs increases, SCE must take steps to ensure that the timing and location of PEV charging do not adversely impact system reliability or add unnecessarily to the cost of supplying electricity. Specifically, PEV load, if left un-managed, could drive additional costs primarily related to (1) system energy, or wholesale generation procurement, and (2) distribution infrastructure upgrades or replacements.

With a significant increase in the number of cars and the amount of Level 2 (3.3 kW and greater) charging expected in SCE's territory, PEV customers – especially when charging at home after work – could create substantial coincident peak loading. Unmanaged PEV load could require SCE to procure additional peak capacity and wholesale energy when it is most costly. Of even greater concern is the impact of unmanaged PEV load on secondary distribution infrastructure, namely transformers. If left un-managed, the combined impact of PEV clustering and sustained overloading on distribution transformers will decrease the lifespan of these assets, or even worse, cause in-service equipment failures which result in outages and require costly emergency replacement.

SCE's PEV Integration capability focuses on load management tools that will help minimize the impacts of PEV charging and save customers money. Specifically, this capability includes enabling time-variant or dynamic rate options that will lead a customer to charge his or her PEV when energy costs are low and manage PEV load to minimize distribution system impacts and maximize customer savings. Although

42 Summary of Pub. Util. Code § 8360(c) - (h); § 8366(a) - (d) in D. 10-06-047, p. 31.
43 Summary of Pub. Util. Code § 8360(a); § 8366(g) in D. 10-06-047, pp. 31-32.
D. 10-06-047, p. 34.
44 D. 10-06-047, p. 34.
45 D.10-06-047, p. 34.

SCE considers PEV charging as it would any other variable driving new load growth, PEVs create unique challenges in that there is uncertainty about how much, where, and when charging will show up on the system. Developing PEV Integration as a smart grid capability will help SCE to identify these PEV loads, manage potential distribution infrastructure upgrades driven by customer adoption of PEV and discretely meter vehicle load as necessary.

In addition to the savings that SCE can accrue through effective integration and load management of vehicle charging, this capability enables a variety of policy objectives that support the use of alternate transportation fuels to achieve required GHG reductions under AB 32. The capability also aligns with several SB 17 / D.10-06-047 smart grid requirements. The PEV-specific TOU rates that SCE makes available to its PEV customers helps motivate them to "actively participate in operations of the grid."[46] To the extent that these rates help avoid on-peak PEV charging, this capability also helps "significantly reduce the total environmental footprint of the current electric generation and delivery system in California."[47] As SCE integrates its offerings with those of third party services providers, this capability will also support "maximum access by third parties to the grid, creating a welcoming platform for deployment of a wide range of energy technologies and management services."[48]

3. Enhanced Customer Engagement

As described in the Vision chapter, active customer participation and engagement is an essential factor that will contribute to the success of the smart grid. With this in mind, SCE is developing its Enhanced Customer Engagement capability that focuses on providing smart meter-generated usage and pricing data to customers to help them understand and manage their energy consumption. Enhanced Customer Engagement will enable customers to reduce their electricity usage by providing them with sufficient information about their own power usage, the rates or true prices associated with that power usage, and the motivation and technological means to make rational economic decisions about how much power they will use and when. This capability works together with DR and PEV Integration by providing information that will increase the effectiveness of customer participation in programs related to each of those capabilities.

Under current state and federal energy policies, customer engagement is a preferred means of managing the growing demand for electricity. In California, the Energy Action Plan II (EAP II) sets forth key action areas for engaging customers in active energy management, including educating customers about the time sensitivity of energy use and the ways to take advantage of dynamic pricing tariffs and other DR

46 Summary of Pub. Util. Code § 8360(c) - (h); § 8366(a) - (d) in D. 10-06-047, p. 31.
47 D. 10-06-047, p. 34.
48 D. 10-06-047, p. 34.

programs as well as providing customers access to their energy use information to allow participation in energy management programs.[49] EAP II explicitly recognizes the importance of technology to achieve its objectives: "[w]e need to develop and tap advanced technologies to achieve [California's energy] goals of reliability, affordability, and an environmentally sound future."[50]

State energy policies strive for customers to understand the impact of managing energy consumption on climate goals, such as AB 32 GHG emissions reductions. In terms of federal energy policy, EISA seeks to enable consumers to better manage their electricity consumption and costs through smart appliances and energy management devices in homes and businesses, and take advantage of time variant electricity pricing, incentive-based load reduction signals, and emergency load reduction signals.[51] These policy objectives indicate that customers need access to the necessary information, tools, and support to enable them to assume active roles in energy management.

Achievement of energy policy objectives requires effective information and outreach to customers to encourage and enable them to participate in the myriad of options available to help them manage their energy usage and costs, such as DR, DG, EE, and PEV programs. It also requires SCE to meet its customers' evolving needs and growing expectations to manage their energy usage and transact business over the internet and through other electronic means. Technology is critical to effective customer engagement to meet the objectives of state and federal policies and SCE's customers' expectations and needs. Implementation of SmartConnect and other technology solutions will provide the necessary systems and automation to effectively communicate with customers about their energy usage and how they can take part in new rates, programs, and services.

By making actionable and understandable energy and price information available to customers, SCE's Enhanced Customer Engagement capability aligns with several SB 17 and D. 10-06-047 smart grid characteristics, including requirements that a smart grid "motivate consumers to actively participate in operations of the grid",[52] "creat[e] a welcoming platform for deployment of a wide range of energy technologies and management services",[53] "support the sale of demand response, energy efficiency, distributed generation, and storage into energy markets",[54] and "significantly reduce the total environmental footprint of the current electric generation and delivery system in California".[55]

49 *See* EAP II, Section II.2., p.5, Key Action No. 8.
50 *See* EAP II, Introduction and Summary p. 2.
51 Titles XII & Title XIII, Energy Independence and Security Act of 2007, Pub. L. 110-140 (EISA).
52 Summary of Pub. Util. Code § 8360(c) - (h); § 8366(a) - (d) in D. 10-06-047, p. 31.
53 D. 10-06-047, p. 34.
54 D. 10-06-047, p. 34.
55 D. 10-06-047, p. 34.

4. Required Infrastructure

Smart grid capabilities in the Customer Empowerment domain will leverage an integrated portfolio of infrastructure investments that enable customer participation in time-variant and dynamic rates and provide customers with the information necessary to participate in these programs.

a) Field Devices

The key field devices required to enable the capabilities in the Customer Empowerment domain are SmartConnect meters that measure customer energy use at hourly or sub-hourly intervals and enable communication of usage and pricing information to customers. The interval usage information collected by smart meters is required to enable time of use and dynamic pricing rates under both the DR and PEV Integration capabilities. SCE may also leverage smart meters to take advantage of PEV-specific metrology solutions to measure vehicle-specific load and accommodate future charging options.

Additionally, SCE will leverage certain customer premise devices as an advanced means of communication with its customers. Certain DR programs, for example, will require devices located at customers' homes and businesses that notify customers of DR events and, in some cases, automatically curtail load. Similarly, emerging PEV charging devices such as smart Electric Vehicle Supply Equipment (EVSE) can help customers make better decisions about their vehicle charging needs.

Finally, energy storage devices located at the customer's premise may eventually play an important role in facilitating permanent load shifting and further integrating vehicle charging in grid operations.

b) Communications Networks

There are two primary communication networks necessary to support Customer Empowerment capabilities: the AMI Network and Premise-Area Networks. The AMI Network allows SCE to retrieve some of the information, such as interval usage data, necessary to manage various DR and PEV tariffs and programs as well as enhance its customer engagement. Premise-Area Networks provide a means of direct communication between SCE's smart meters and customer devices that will facilitate provision of information to customers as well as their participation in DR and PEV programs.

Other communications networks are required to support specific programs under SCE's DR and PEV capabilities. For instance, SCE will have to utilize its Field Area Network (FAN) to communicate DR information with larger customers that are not served by SCE's SmartConnect AMI network. In addition, emerging technologies for PEV metering and load management may require premise area networks as well as power line carrier communications (PLC) and, potentially, broadband over wireless.

c) Management & Control Systems

Customer Empowerment capabilities rely on several back office systems.

AMI Back Office systems, such as the Meter Data Management System (MDMS) and Network Management System (NMS), are used to gather and compile a customer's usage data as well as coordinate the sending of data back to a customer's meter. In addition, SCE will need Customer Information Systems (CIS) that (1) track customer contact preferences and/or notify customers via email, phone, text message, page, and fax of DR events, (2) track customer enrollment in DR and PEV programs, program termination, device/enabling technology information, service orders, and ongoing eligibility requirements, and (3) settle program and tariff performance and provide credits or bills to customers. Finally, SCE will need to upgrade customer information systems to accommodate new PEV work processes, new rates, and enhanced customer support services.

SCE will also enhance its online presence at SCE.com to provide education and outreach to help customers navigate the many options that will be available to them to assist with energy management. For example, customers will be able to go to SCE.com and streamline the installation of metering or EVSE hardware and select a tariff that best suits their charging preferences. SCE.com is also an important channel through which a customer will be able to access energy usage information as well as access tools that will help them with managing energy costs and determining the best rate for their load profile. Finally, SCE.com provides DR program content and program details, such as current and historical event information.

Beyond these core customer information management systems, another infrastructure element that will enable Customer Empowerment capabilities is SCE's Advanced Load Control System (ALCS). ALCS can help SCE coordinate notifications about and responses to DR events, properly manage PEV loads, and offer Home Area Network (HAN) capabilities to its customers. SCE is forecasting tremendous growth in this emerging market with widespread availability of standardized HAN devices through retail distribution channels to consumers. ALCS plays a crucial role in enabling SCE to realize energy conservation benefits associated with implementing the SmartConnect program.

In addition, SCE expects to provide an interface so that third party DR aggregators, vehicle charging providers, and energy management providers can access customer usage information. This interface will leverage the Energy Service Provider Interface (ESPI) standard and will enable a robust, competitive market for a variety of energy service models designed to drive DR program growth, provide customers with better and more actionable information and facilitate integration of PEVs.

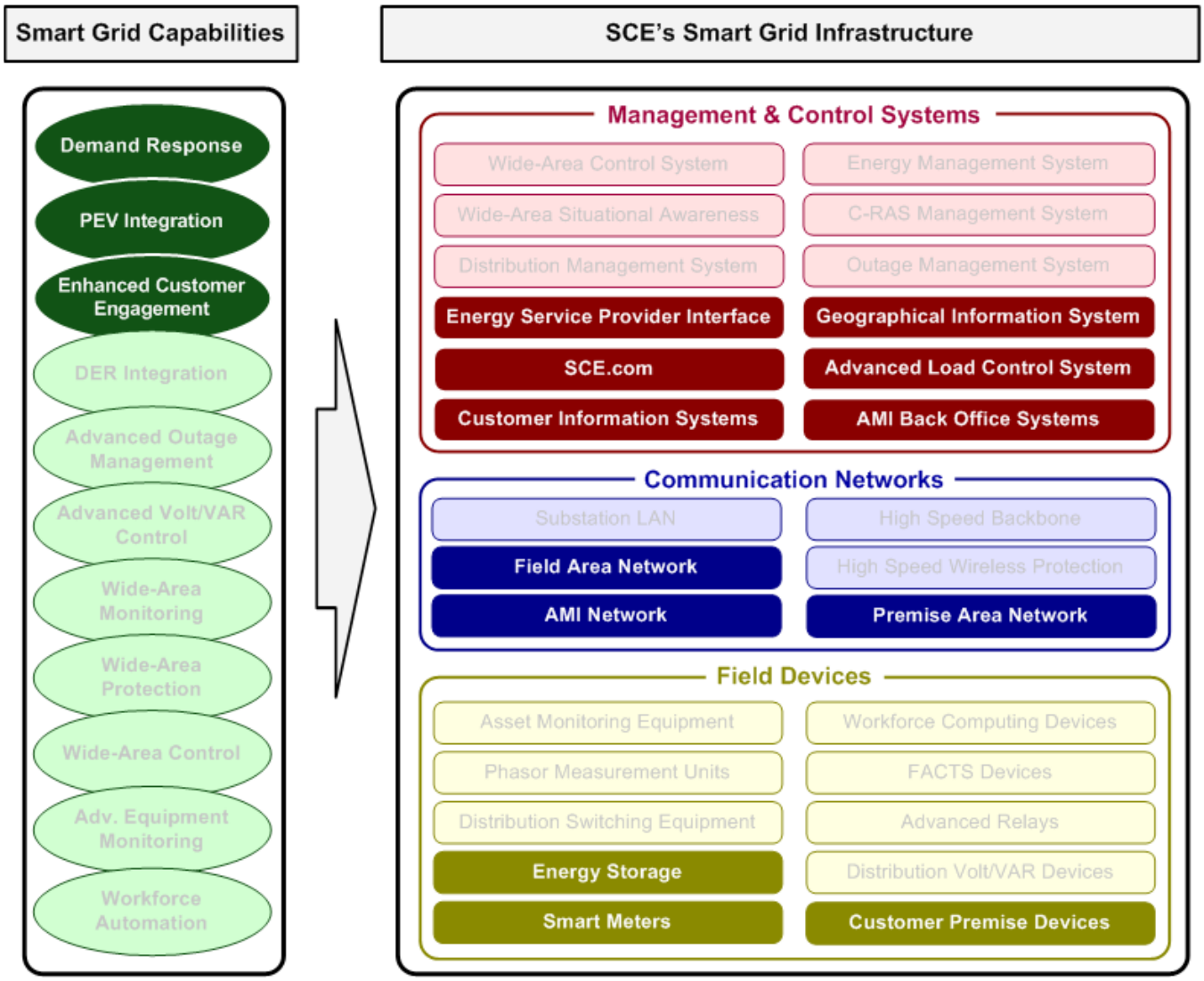
Finally, SCE will implement an Alerts & Notification system to automate the delivery of important information customers need to manage their energy usage. SCE will also leverage its geographical

information system (GIS) as a valuable tool for maintaining and coordinating location-specific information about DR events, energy prices and participating customers.

d) Summary

Figure 14 below summarizes the infrastructure SCE plans to deploy to support its DR, PEV integration and Enhanced Customer Engagement capabilities in the Customer Empowerment domain.

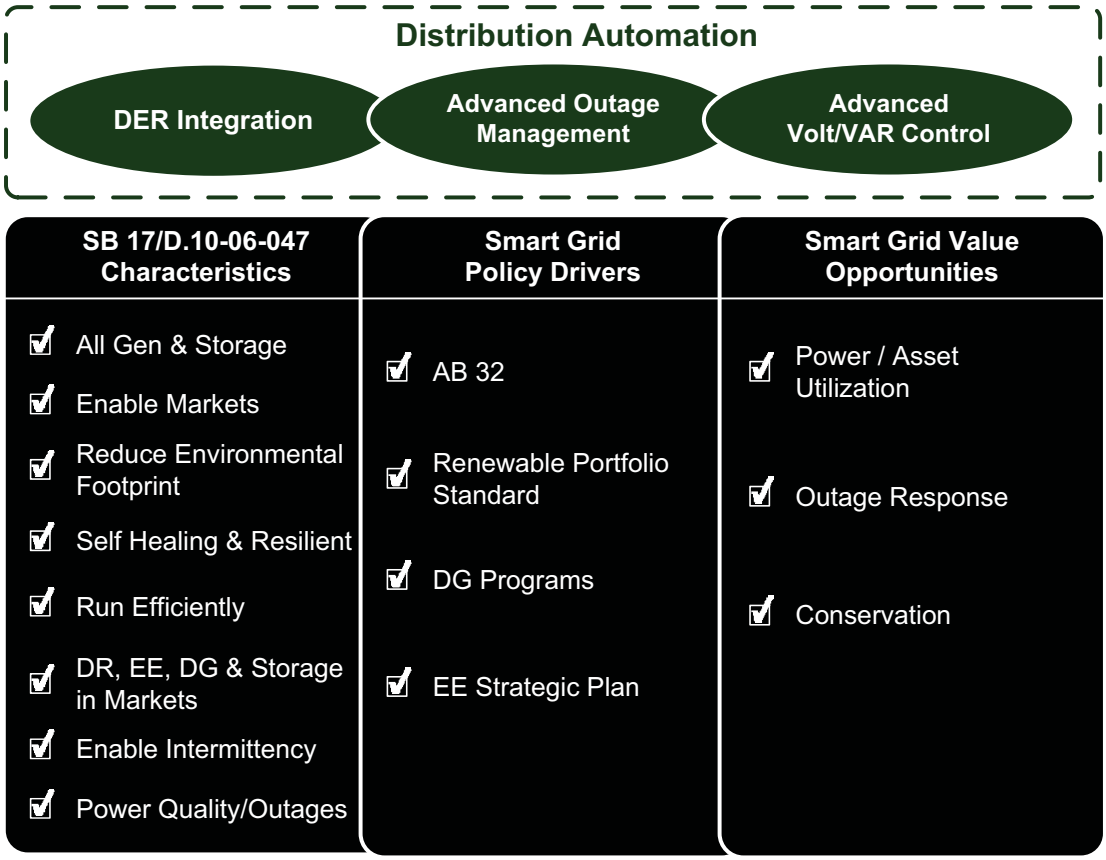
Figure 14 – Customer Empowerment Capabilities and Required Infrastructure



B. Distribution and Substation Automation Capabilities

To address the complexities associated with integrating distributed energy resources, as well as take advantage of opportunities to save customers money and improve its outage response ability, SCE is working towards an integrated distribution and substation automation solution. SCE will work towards enabling this domain's three smart grid capabilities depicted in Figure 15 – DER Integration, Outage Management and Advanced Volt/VAR Control – to bring about a more advanced, flexible and responsive distribution system that supports a cleaner energy future.

Figure 15 – Distribution and Substation Automation Drivers



1. Distributed Energy Resource Integration

SCE defines Distributed Energy Resource (DER) Integration as the ability to safely and reliably incorporate high penetrations of DER on its distribution system. DER are located close to and typically sized to match the load they serve. Specific technologies that fall under the DER heading include distribution side generation, energy storage and DR technologies.

DER Integration is a policy-driven capability that will provide SCE with the tools necessary to reliably operate its distribution system as customers and SCE begin to utilize DER. As discussed in Section III.A.2,

several DER programs, driven in large part by the need to meet AB 32 and RPS requirements, could lead to as much as 4,000 MW of renewable generation interconnecting to SCE's distribution system in the next decade. At the same time, DR and PEV programs described in the Customer Empowerment section as well as the ZNE homes and businesses contemplated by California's Long Term Energy Efficiency Strategic Plan will lead to additional DER installations as home and business owners begin to produce their own power to achieve zero net energy.

Interconnection of DER at the scale implied by California's policy goals presents two specific challenges for distribution system operations. First, increased DER penetration will increase the magnitude of voltage fluctuations on distribution circuits to a level that SCE is not currently equipped to manage. The fluctuations may be caused by PV generators, as well as rapid increases and decreases in customer load that may result from DR programs and PEV charging. In addition, large installations of DG may require changes to SCE's protection schemes and create capacity issues on the circuits where these facilities interconnect.

To safely integrate power from these generators, SCE is focusing on DER Integration as a key smart grid capability over the next 10 years. This capability directly supports many SB 17 / D. 10-06-047 smart grid characteristics, specifically requirements that a smart grid "accommodate all generation and storage options"[56] and "enable penetration of intermittent power generation sources."[57] In addition, as this capability lays the foundation for better utilization of DER as a system resource, DER Integration also helps "enable electricity markets to flourish"[58] and helps deliver a smart grid that has "the infrastructure and policies necessary to enable and support the sale of DR, energy efficiency, DG, and storage into energy markets as a resource among other things, on equal footing with traditional generation resources."[59]

2. Advanced Outage Management

Advanced Outage Management is a capability that allows SCE to rapidly detect and isolate faults when they occur, immediately restore service to as many customers as possible and provide information to customers about outages in real-time.

Faults and other system disturbances due to storms, equipment failure, traffic accidents (e.g., cars driving into poles) and other factors are unavoidable. Advanced Outage Management will allow SCE to develop circuits that are "self-healing" to reduce the number of customers affected by these incidents and enable

56 Summary of Pub. Util. Code § 8360(b) - (g); § 8366(a), (e) - (g) in D. 10-06-047, p. 31.
57 Summary of Pub. Util. Code § 8360(c), (g), & (j); § 8366(a) - (d) in D. 10-06-047, p. 32.
58 Summary of Pub. Util. Code § 8360(b) - (j); § 8366(a) - (d) in D. 10-06-047, p. 31.
59 D. 10-06-047, p. 34.

SCE to return service more quickly to those customers that are affected. In the future, certain technologies may even allow SCE to anticipate certain factors that could lead to outages and prevent them altogether. Beyond the field device-level response to faults, Advanced Outage Management involves the gathering of information from the field in real-time so that SCE can provide information to affected customers about the nature and expected duration of outages that affect them.

The self-healing capabilities of Advanced Outage Management are a key goal of federal and state smart grid policy, and this capability constitutes a critical first step towards implementing this smart grid vision. The capability is directly aligned with the SB 17 goal that smart grids be "self-healing and resilient"[60] and "provide higher quality power that will save money wasted from outages."[61]

3. Advanced Volt/VAR Control

SCE defines Advanced Volt/VAR control (AV/VC) as the optimization of voltage and reactive power on the distribution system to enhance power quality and decrease energy consumption.

Electric utilities and regulators have long recognized the savings potential associated with optimizing the voltage level at which utilities deliver electricity to their customers. For normal 120-volt service, utilities are typically required to serve customers within an allowable band of +/- 5% of 120 volts, or between 114 to 126 volts.[62] However, providing service in the lower half of this band (i.e., between 114 and 120 volts) can result in substantial conservation savings. This concept is not new. The Commission itself recognized that between 1976 and 1978, California utilities' efforts to optimize voltage resulted in savings of over one billion kWh throughout the state.[63]

As further discussed below, smart grid technologies now provide utilities with the ability to deliver this capability more effectively than in the past. AV/VC presents SCE with the ability to deliver substantial customer savings, and is aligned with the SB 17 / D. 10-06-047 goals of a smarter grid that "run[s] more efficiently."[64] In addition, by reducing overall electricity consumption and therefore power production, this capability helps "significantly reduce the total environmental footprint of the current electric generation and delivery system in California."[65]

60 D. 10-06-047, p. 30.
61 D. 10-06-047, p. 31.
62 California utilities are required to serve residential and commercial load with voltage in the band of +0 to -5 percent and industrial and agricultural loads within +5 percent to -5 percent. See SCE's Tariff Book Rule 2 (available at http://www.sce.com/AboutSCE/Regulatory/tariffbooks/rules).
63 D. 02-03-024, p. 4.
64 Summary of Pub. Util. Code § 8360(a); § 8366(g) in D. 10-06-047, pp. 31-32.
65 D. 10-06-047, p. 34.

4. Required Infrastructure

The smart grid infrastructure that SCE will deploy to enable its Distribution and Substation Automation capabilities will constitute an integrated solution that will provide SCE and its customers with a more robust distribution system. This advanced distribution system is essential for integrating DER driven by California's energy policies, and it will also allow SCE to deliver savings to customers and improve its response to outages.

a) Field Devices

To enable capabilities in the Distribution and Substation Automation domain, SCE will need a variety of communicating field devices on its distribution circuits and in its distribution substations. These devices include controls for capacitor banks that will help SCE achieve AV/VC. SCE will also need more flexible voltage regulation equipment to better integrate DER. These devices may be installed at SCE's distribution substations or along its distribution circuits.

Distribution and Substation Automation capabilities will also require relays and switching equipment that can help SCE isolate faults and reconfigure circuits to restore power to customers. Specifically, fast-acting switching devices are the foundational building blocks for the self-healing circuit at the center of SCE's Advanced Outage Management capability. The more flexible distribution system enabled by this infrastructure will also help SCE safely integrate DER and optimize their uses as an energy resource.

Finally, SCE can leverage elements of its AMI to improve its delivery of capabilities in the Distribution and Substation Automation domain. SCE's smart meters will be necessary to provide the net energy metering capability required to measure and compensate surplus generation from DER installations. In addition, smart meters can take voltage readings at the customer site and provide useful additional data points to optimize voltage regulation for SCE's AV/VC capability.

b) Communications Networks

The smart grid capabilities in the Distribution and Substation Automation domain require communication with devices located on SCE's distribution circuits and its distribution substations. To enable this communication, the main networks required are SCE's Field Area Network (FAN) and its Substation Local Area Network (LAN). These networks will allow SCE to remotely control and configure the field devices described above located on SCE's distribution circuits as well as those installed in SCE's substations.

For certain applications related to Distribution and Substation Automation capabilities, SCE will need more specialized networks. Specifically, the self-healing circuit contemplated in the Advanced Outage Management capability requires a High-Speed Wireless Protection Communications Network. This

application requires a network with very low latency to enable the switching devices to act quickly enough to isolate faults.

Finally, voltage readings from smart meters that will help SCE deliver its AV/VC capability will be sent over SCE's AMI Network.

c) Management & Control Systems

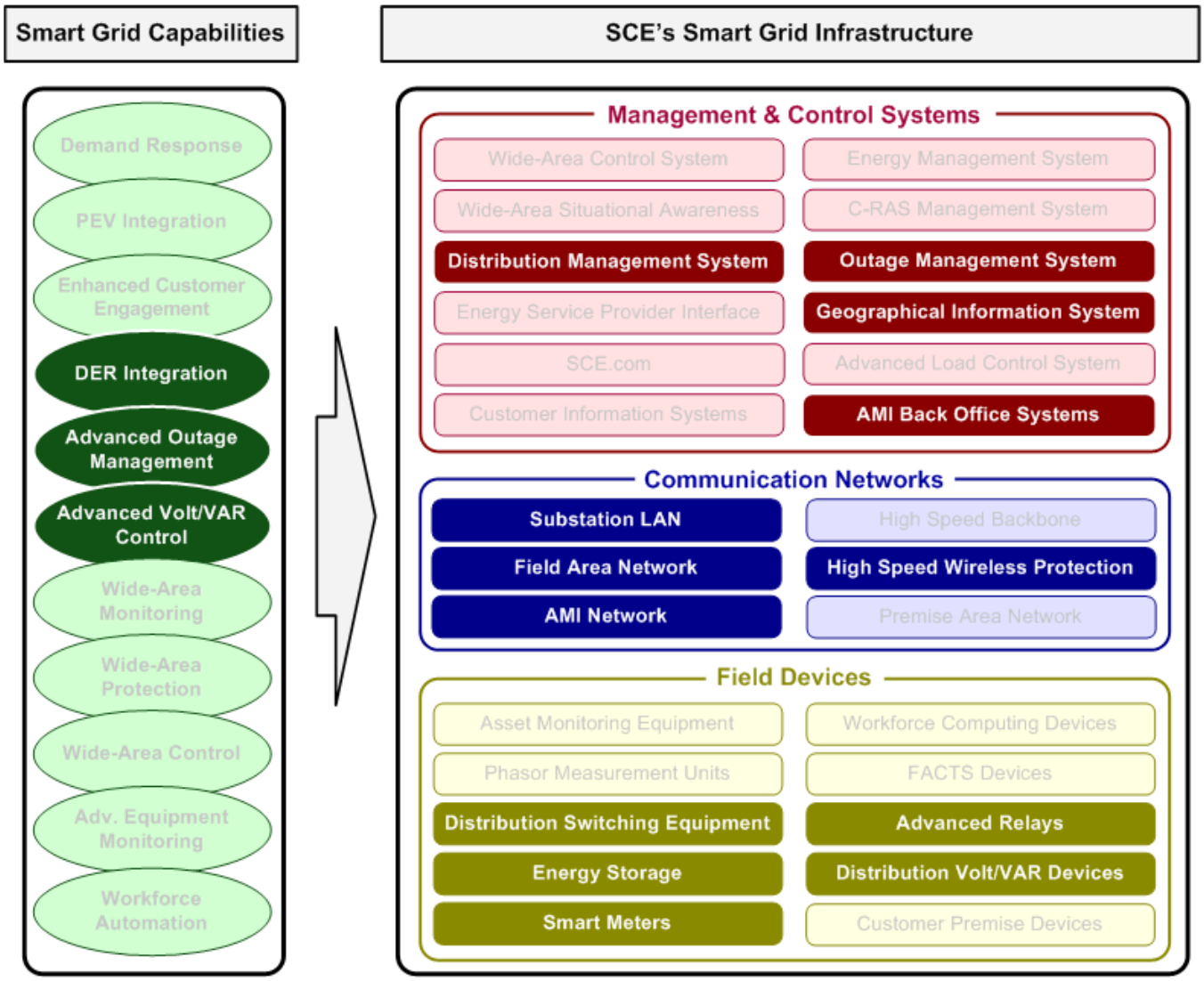
The main management system required to enable SCE's Distribution and Substation Automation capabilities is a Distribution Management System (DMS). A DMS is required to configure and coordinate operation of the field equipment deployed to support DER Integration and Advanced Outage Management. A DMS also includes the software required for SCE to deliver AV/VC.

Capabilities in this domain will leverage several other management systems beyond the DMS. SCE's Outage Management System (OMS) maintains information about outages and will help organize SCE's deployment of trouble crews to support Advanced Outage management. The company's GIS is also a key component in that it will, in connection with SCE's AMI network and systems, establish an accurate representation of transformer-to-customer connectivity, allowing outages reported through the AMI meter to be attributed to the correct circuit or field device. Finally, SCE will utilize its AMI Back Office System, where data about customer-site voltage will be housed.

d) Summary

Figure 16 summarizes the infrastructure required to support SCE's smart grid capabilities in the Distribution and Substation Automation Domain.

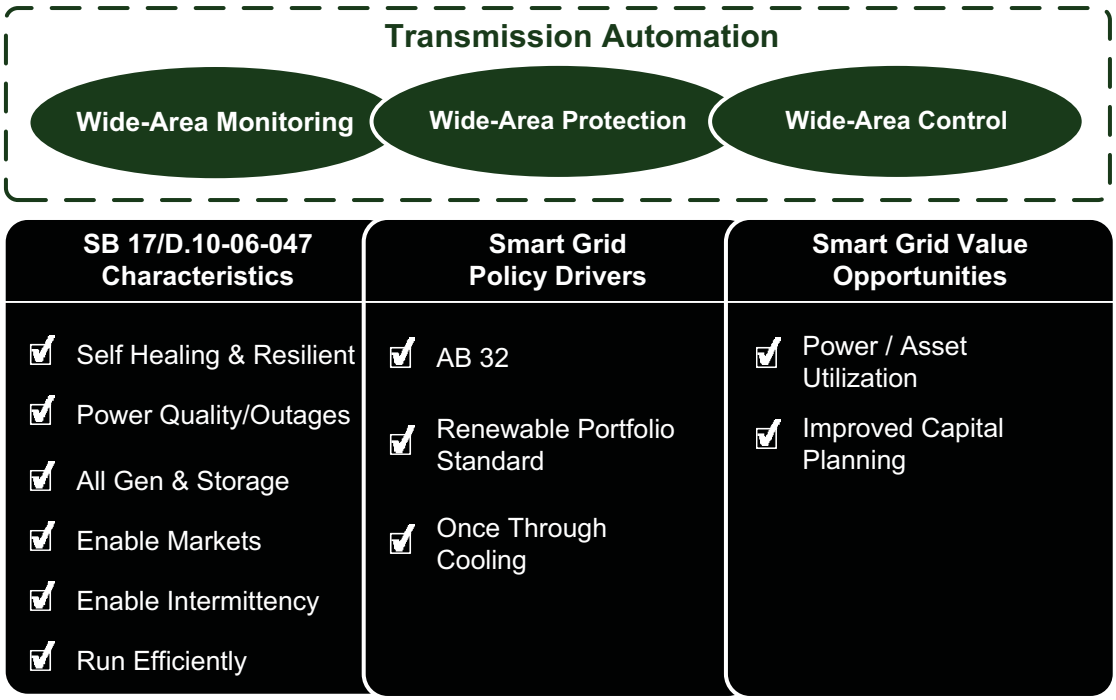
Figure 16 – Distribution and Substation Automation Capabilities and Required Infrastructure



C. Transmission Automation Capabilities

In the domain of Transmission Automation, SCE is focusing on three tightly intertwined capabilities – Wide-Area Monitoring, Wide-Area Protection and Wide-Area Control – with the aim of enhancing the resiliency of the transmission system as SCE and other western states utilize increasing amounts of bulk renewables. These capabilities will also move SCE towards better utilization of its transmission infrastructure through dynamic line ratings in the future. The sections below describe Wide-Area Monitoring, Protection and Control and the infrastructure required to enable these capabilities in more detail.

Figure 17 – Transmission Automation Capability Drivers



1. Wide-Area Monitoring, Protection and Control

Like DER Integration, Wide-Area Monitoring, Protection and Control (collectively, WAMPAC) are policy-driven capabilities that should enable SCE to maintain transmission system stability as a variety of mandated changes make transmission system operations more complicated.

WAMPAC consists of three elements that SCE will develop during the period covered by the Deployment Plan. The first element of this capability, Wide-Area Monitoring, refers to the ability to monitor bulk power system conditions (including voltage, current, frequency and phase angle) across large geographic areas in near real-time.[66] Wide-Area Monitoring provides system operators with current information about

66 FERC defines wide-area situational awareness as "visual display of interconnection-wide system conditions in near real-time at the reliability coordinator level and above". *See* FERC, Smart Grid Policy, Docket No. PL09-4-000 (July 16, 2009).

emerging threats to transmission system stability, enabling preventative action to avoid wide-scale black outs. The second element, Wide-Area Protection, refers to centralized coordination of high-speed, communicating transmission protection equipment and associated systems. Wide-Area Protection will allow SCE to detect events or conditions like transmission line over-loading and initiate planned protection actions such as generation tripping or load shedding. Finally, Wide-Area Control enables automated responses to the threats detected through Wide-Area Monitoring. Wide-Area Control would help SCE respond to stability problems that can develop and become manifest in very short periods of time where human intervention might be too slow.

Several state and federal policy initiatives drive SCE's need to develop WAMPAC as a smart grid capability. At a fundamental level, the decades-long transition from utility-owned generation to competitive wholesale generation markets has increased the degree of interconnection and power exchange between transmission systems. Utilities like SCE now need information about transmission system conditions from utility and non-utility entities throughout the Western Interconnection to ensure reliability within their own service territories. WAMPAC will allow SCE to operate the transmission system safely and reliably in this increasingly complex environment.

Compounding the challenges associated with the increasingly interconnected nature of the bulk power system in the western United States, RPS targets throughout the West will increase the number of generation interconnections that transmission system operators must monitor as developers complete construction of new solar arrays and wind farms in geographically dispersed locations. In addition, the intermittent nature of power generated by these renewable facilities will increase system operators' need for real-time information about voltage, current and other metrics describing system conditions.

Analogous to the impacts of renewables targets, the recently enacted State Water Board's OTC policy[67] may create reliability problems that WAMPAC can help address. Losing resources as a result of OTC-related retirements could destabilize the transmission system in a number of ways, and one of SCE's goals in pursuing WAMPAC as a smart grid capability is providing SCE's transmission system operators with tools to mitigate the stability impacts of this loss of generation.

In addition to the reliability-based benefits of WAMPAC, developing WAMPAC as a capability will allow it to better utilize its transmission infrastructure through dynamic asset rating. As discussed in Section III.A.3.c), limited access to real-time information forces transmission system operators to limit loading of transmission equipment based on path ratings which are developed under worst case scenarios. These

67 On May 4, 2010 the State Water Board adopted a Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Policy). The Policy establishes technology-based standards to implement federal Clean Water Act § 316(b), 33 U.S.C. § 1326(b), which requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact.

ratings often leave substantial amounts of available transmission capacity un-used. Armed with the reliable real-time information that SCE will generate through its WAMPAC capabilities, system operators could better utilize this spare capacity, helping to defer and possibly avoid transmission investment.

To summarize, the move towards competitive generation markets and renewable portfolio targets throughout the West will increase the complexity of operating the bulk power system by increasing the number of geographically dispersed interconnections. At the same time, increasing penetration of renewable power on the transmission system creates specific challenges for maintaining system stability. Both trends create the need for SCE to develop WAMPAC as a core smart grid capability. While these policy drivers make WAMPAC a critical capability, it will also allow SCE to produce value for its customer by better utilizing transmission infrastructure. Therefore, the impact of renewable portfolio targets on both interconnection volume and system stability drives the need for SCE to develop WAMPAC as core smart grid capability, which it can leverage to produce substantial customer value.

WAMPAC directly supports several smart grid characteristics that are identified in SB 17 and D. 10-06-047. First, WAMPAC uses real-time information from embedded sensors and automated controls to anticipate, detect, and respond to system problems,"[68] with the goal of providing "more stable and reliable power to reduce downtime."[69] In addition, WAMPAC will "enable penetration of intermittent power generation sources"[70] on the bulk power system. By providing utilities with the information needed to safely incorporate wholesale power from interconnection points throughout the West, WAMPAC also supports the goals of "accommodat[ing] all generation and storage options,"[71] and "enabl[ing] electricity markets to flourish."[72] Finally, by enabling dynamic asset ratings, this capability also supports the SB 17 goal of a smart grid that "runs more efficiently."[73]

2. Required Infrastructure

Implementing the WAMPAC capabilities in the Transmission Automation domain will require SCE to invest in (1) field devices that can take measurements of transmission system conditions many times per second, (2) a secure, high speed communications network that can transmit those measurements to system operators, and (3) management and control systems that can store and process this large volume of data in real-time as well as coordinate operation of field devices for protection and control purposes.

68 Summary of Pub. Util. Code § 8360(a), (b), & (d); § 8366(a), (e) - (g). in D. 10-06-047, pp. 30-31.
69 Summary of Pub. Util. Code § 8360(a) & (b); § 8366(a), (e) - (g) in D. 10-06-047, p. 31.
70 Summary of Pub. Util. Code § 8360(c), (g), & (j); § 8366(a) - (d) in D. 10-06-047, p. 32.
71 Summary of Pub. Util. Code § 8360(b) - (g); § 8366(a), (e) - (g) in D. 10-06-047, p. 31.
72 Summary of Pub. Util. Code § 8360(b) - (j); § 8366(a) - (d) in D. 10-06-047, p. 31.
73 Summary of Pub. Util. Code § 8360(a); § 8366(g) in D. 10-06-047, pp. 31-32.

a) Field Devices

A number of field devices will play roles in WAMPAC. Phasor measurement units (PMU) represent the most promising technology available as field devices to measure transmission system conditions in real-time. PMUs are able to measure voltage, current, frequency, and phase angle from many points on the transmission system at a rate of 30 scans per second. Advanced relays will also be an important part of wide-area protection. Relays that perform multiple functions of "send," "receive" and "self-check" as well as ensure a level of redundant functionality will be required to meet North American Electric Reliability Corporation (NERC) / Western Electricity Coordinating Council (WECC) requirements for transmission protection. Finally, WAMPAC capabilities would be enhanced by energy storage systems and Flexible Alternating Current Transmission System (FACTS) devices operated in an integrated fashion in response to power system challenges associated with high penetration of intermittent resources and OTC-related retirements.

b) Communications Networks

WAMPAC will require two key telecommunications networks. SCE will need to utilize a high speed telecommunications backbone that connects substation devices with SCE's back-end systems. This network will have to be robust enough to support exchanges of large volumes of PMU-generated data and secure enough to support protection and control communications. The Substation LAN will also be required to serve communications with new devices such as PMUs, FACTS devices, and advanced relays that will be installed in SCE's bulk power substations.

c) Management & Control Systems

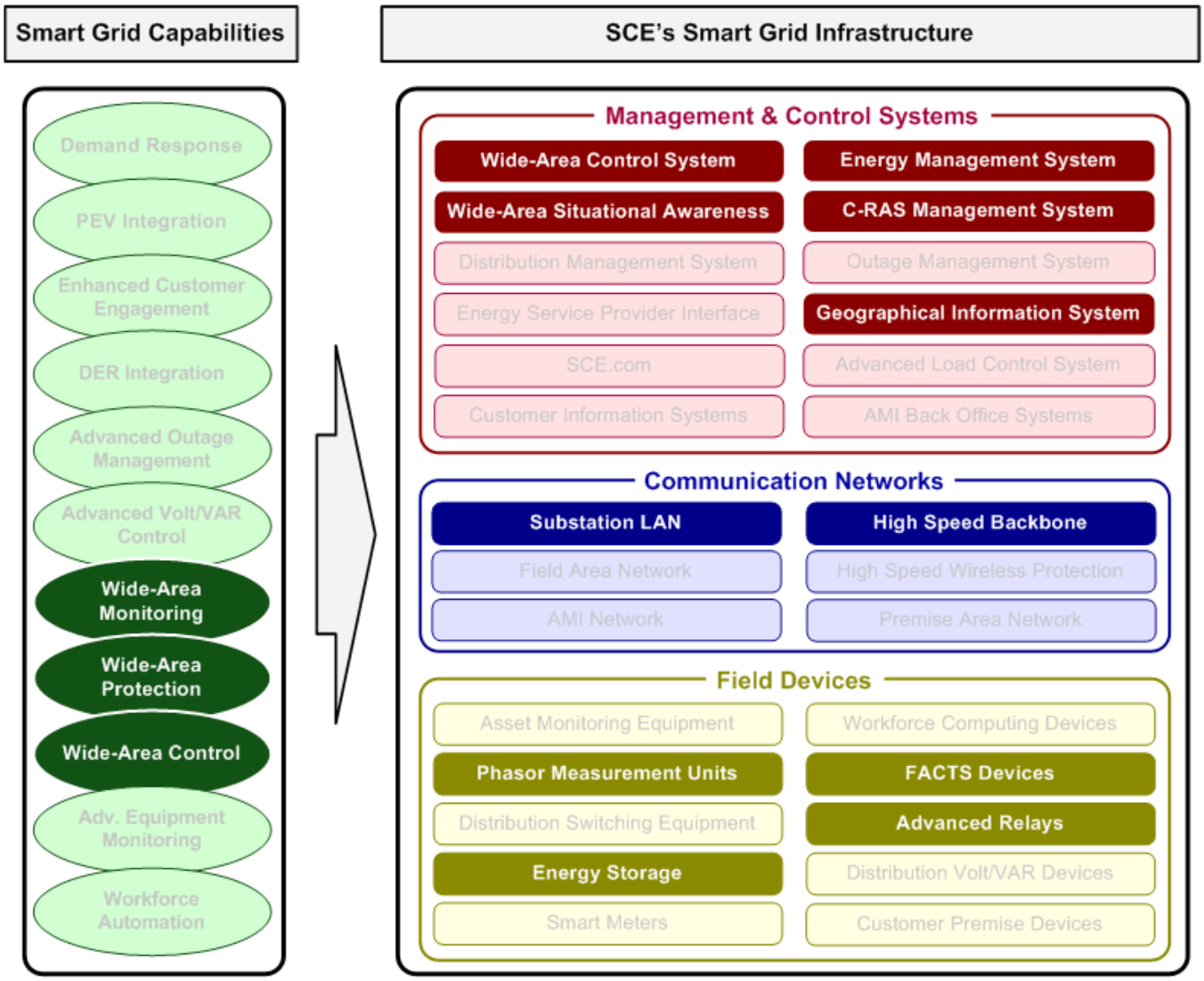
WAMPAC will leverage several management and control systems. In order to make use of the data collected by PMUs, a Wide-Area Situational Awareness System (WASAS) will be required. WASAS is the visualization software that displays phasor measurement information to system operators and engineers. To enable wide-area protection, SCE will also need a central system to coordinate operation of its Remedial Action Schemes (RAS). RAS are a key tool that SCE uses to protect elements of its transmission system from overloading and SCE's Wide-Area Protection capability will require a Centralized Remedial Action Scheme (C-RAS) system to coordinate its growing number of RASs. In addition to the WASAS and C-RAS management system, SCE also contemplates a Wide Area Control System to enable the WAMPAC capability. This system will manage complex control algorithms to manage renewable integration and intermittency as well as facilitate dynamic asset ratings.

Other management and control systems that WAMPAC will leverage include SCE's GIS to incorporate locational information into the data gather by PMUs, and the Energy Management System (EMS) to coordinate control of field devices.

d) Summary

Figure 18 summarizes the infrastructure required for SCE to develop its Transmission Automation capabilities.

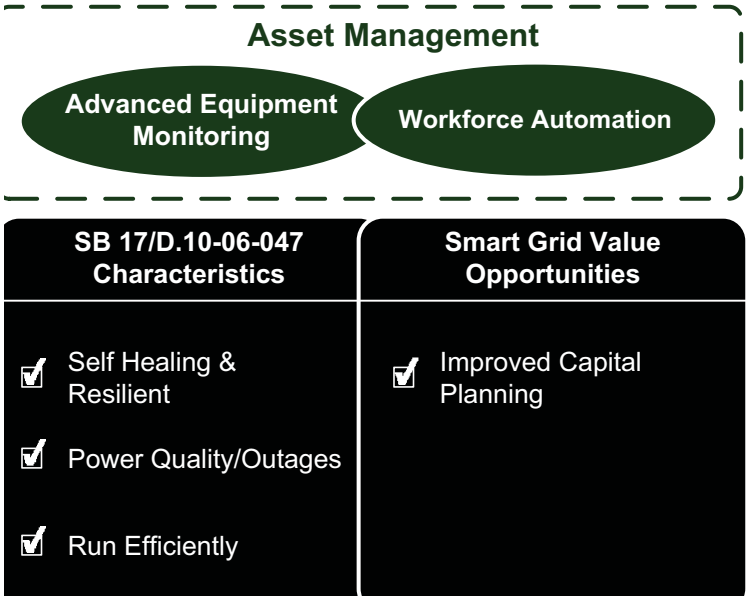
Figure 18 – Transmission Automation Capabilities and Required Infrastructure



D. Asset Management Capabilities

Smart grid capabilities in the Asset Management domain – Advanced Equipment Monitoring and Workforce Automaton – support SCE's efforts to avoid failures of critical energy infrastructure as well as manage costs associated with maintaining and replacing this infrastructure. The sections below describe both of these capabilities in more detail.

Figure 19 – Asset Management Capability Drivers



1. Advanced Equipment Monitoring and Workforce Automation

Advanced Equipment Monitoring and Workforce Automation will provide SCE with the ability to manage the maintenance and replacement of energy infrastructure based on real-time information about the health of that equipment.

SCE's ability to provide reliable electric service to its customers rests to a large degree on ensuring that infrastructure such as poles, transformers, switches, circuit breakers, capacitors, cable, and conductors are properly maintained. Part of maintaining SCE's transmission and distribution system involves replacing these assets on a periodic basis, and SCE replaces infrastructure through three main programs. In general, programs associated with replacement of equipment after their in-service failure are described as Breakdown Capital Maintenance. Programs associated with the replacement of equipment as a result of inspections are described as Preventive Capital Maintenance. Programs associated with equipment replacement using a risk/reliability-based approach are described as Infrastructure Replacement.

Certain types of equipment failures cause substantial damage and expense, and pose significant risks to utility workers. For example, bulk power system transformer failures can pose a threat to employee safety,

in addition to extended unplanned outages. Equipment like these transformers must therefore be replaced based on inspections or a risk/reliability-based approach before they fail. Unfortunately, even with current state-of-the art inspection technology, for most types of equipment, inspections reveal only external deterioration. Problems inside the equipment usually cannot be detected. Similarly, while SCE's existing risk/reliability-based approaches are effective, SCE would benefit from more detailed information about the likelihood of failure for a given piece of equipment.

Asset Management capabilities hold the promise of providing SCE personnel with valuable and currently unavailable information about the condition of its service equipment. SCE can use this information to make better and safer decisions about how and when to replace infrastructure whose failure can create substantial expense and the risk of serious personal injury.

SCE has prioritized Advanced Equipment Monitoring and Workforce Automation capabilities because they will deliver key benefits and are aligned with SB 17's smart grid features. The capability should allow SCE to save money through more effective capital planning and by avoiding unplanned outages and emergency repairs. It will also help SCE protect its employees and the public. These avoided service disruptions and emergency costs align with SB 17 / D. 10-06-047 characteristics by helping SCE "run more efficiently"[74] and "create a grid that is self-healing and resilient."[75]

2. Required Infrastructure

To enable capabilities in the Asset Management domain, SCE will have to deploy (1) field devices to take measurements of equipment health as well as computing devices for its personnel, (2) networks that support communications with personnel and the particular equipment that the equipment monitoring devices will measure, and (3) management systems to process all of this data.

a) Field Devices

Gathering of real-time information about the health of transmission and distribution system infrastructure will be accomplished through deployment of field devices that have the ability to collect such information while the asset remains in service. The particular field devices that SCE will require to enable equipment monitoring will depend on the equipment targeted for monitoring. SCE's current plans for this capability include monitoring of bulk power system transformers and pole-top transformers on the distribution system. SCE will use Dissolved Gas Analysis (DGA) technology and bushing monitoring devices for bulk power transformers. On the distribution system, SCE is working with our transformer supplier to develop

74 Summary of Pub. Util. Code § 8360(a); § 8366(g) in D. 10-06-047, pp. 31-32.
75 Summary of Pub. Util. Code § 8360(a), (b) & (d); § 8366(a), (e) - (g). in D. 10-06-047, pp. 30-31.

a new type of "smart" transformer that includes temperature monitoring and communications equipment that can send temperature data back to SCE. Both of these devices are discussed in more detail in the Roadmap section below.

In addition to these equipment monitoring devices, SCE will also have to equip its workforce with computing devices to better respond to equipment service needs.

b) Communications Networks

The ability to transmit the data gathered by these field devices back to SCE system operators depends on the existence of a robust telecommunications networks. On the transmission system, the High Speed Backbone accomplishes this by connecting transmission-level substations with SCE's back-end systems through a high-bandwidth fiber network. The substation LAN is also critical in that it connects all equipment within the substation to the High Speed Backbone network. On the distribution system, the FAN connects both distribution field devices and workforce computing devices with back-end systems.

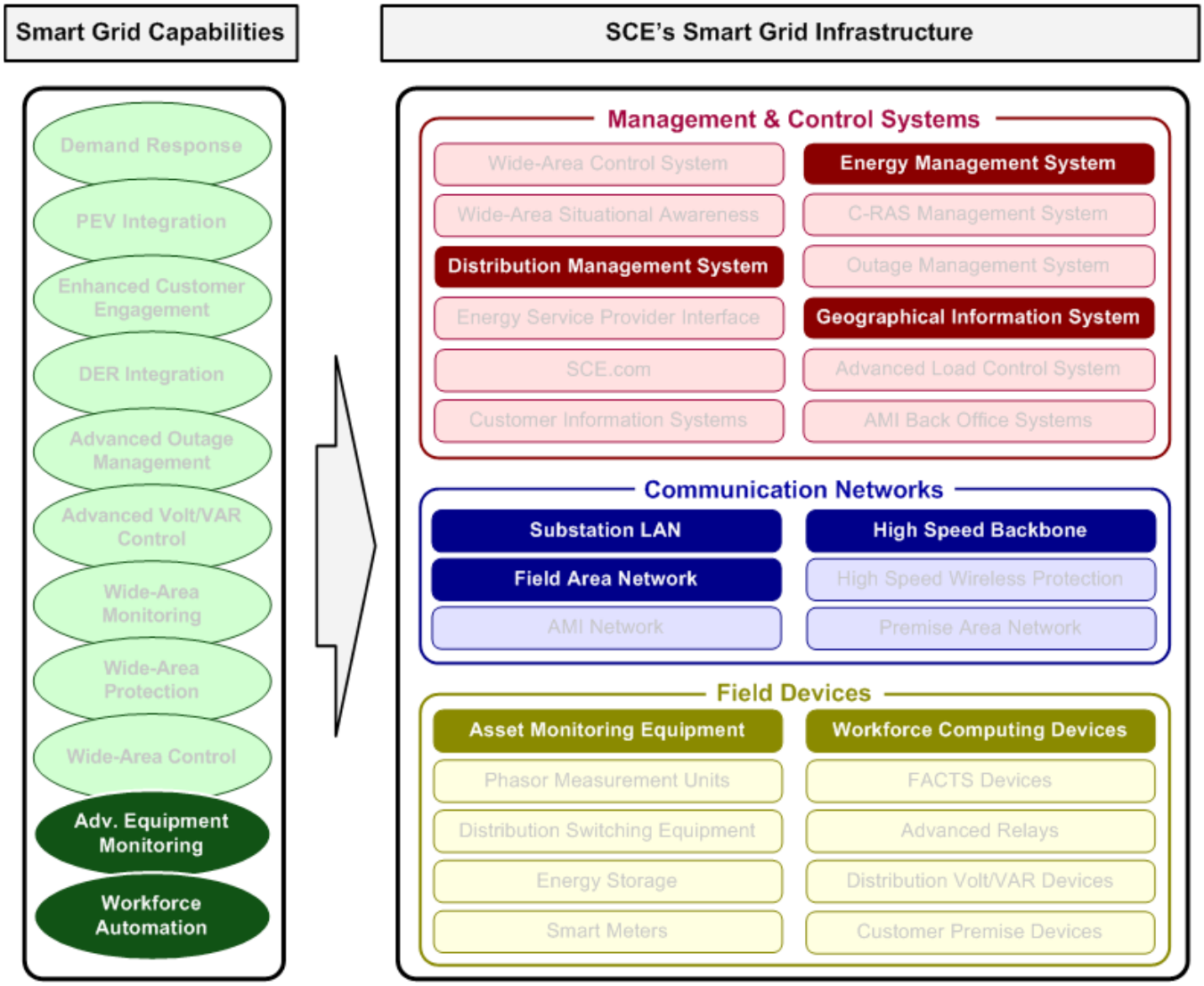
c) Management & Control Systems

Once the data from the field devices has been transmitted, it resides in the EMS (transmission data), and the DMS (distribution data), where it can be viewed and acted upon by system operators. The GIS also plays a role in this capability by maintaining an accurate representation of asset connectivity, physical location in the field, and condition.

d) Summary

Figure 20 on the next page summarizes the infrastructure required to support the Asset Management capabilities.

Figure 20 – Asset Management Capabilities and Required Infrastructure

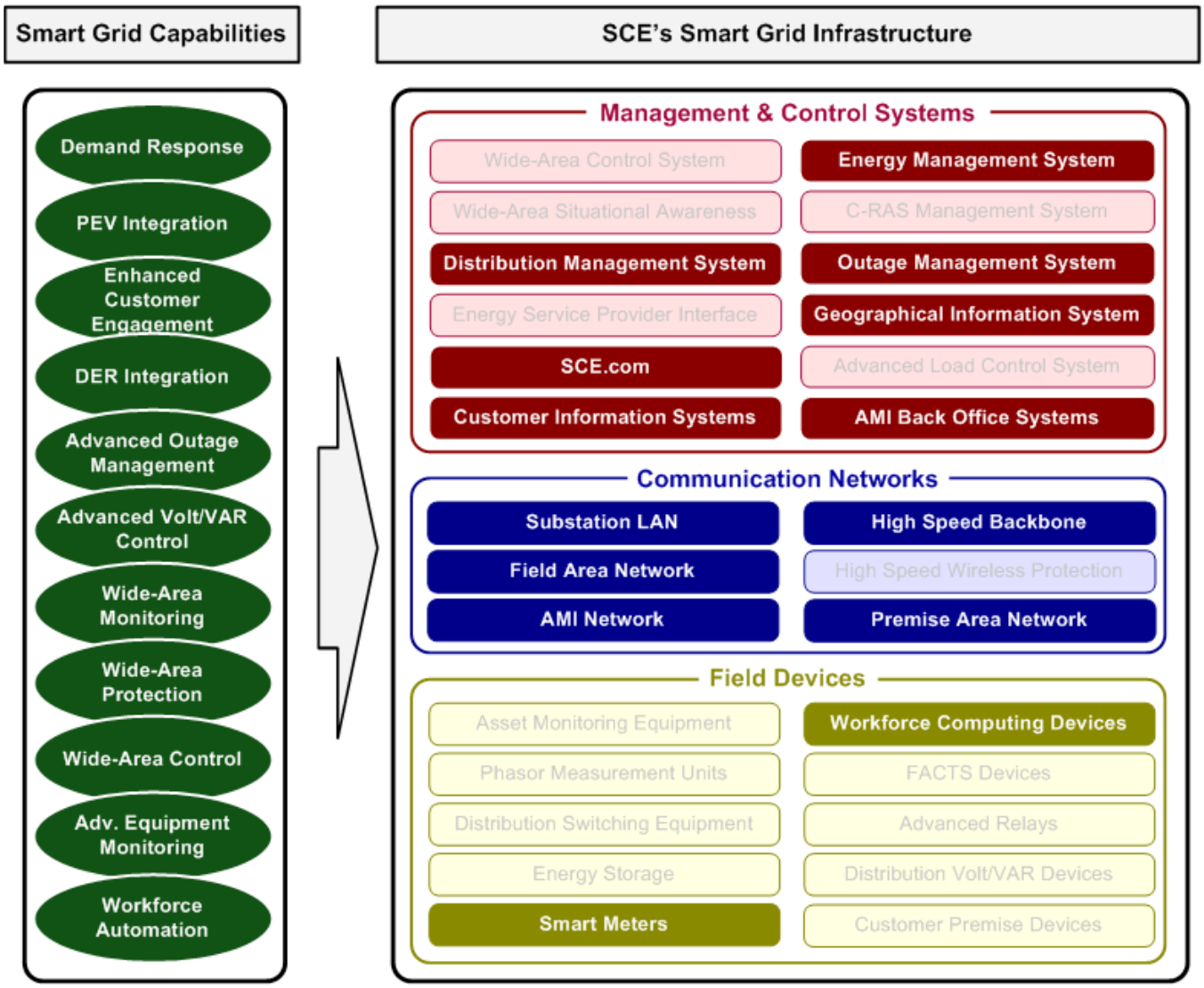


E. Platform Baseline and Roadmap

As discussed in Chapter IV, a key part of SCE's strategy involves identifying platform infrastructure elements. This infrastructure is required to serve multiple smart grid capabilities as well as other conventional utility functions. Identifying this infrastructure is important because it must be designed to serve a range of capabilities in order to avoid expensive integration costs in the future.

Figure 21 below displays the infrastructure elements discussed in the preceding sections that SCE considers platform investments. The sections that follow will describe the baseline state of deployment of this infrastructure as well as SCE's deployment roadmap through 2020. This infrastructure forms a foundation on which SCE's smart grid capabilities will be developed.

Figure 21 – Platform Infrastructure



1. Advanced Metering Infrastructure

SCE's AMI consists of smart meters, the AMI network, and AMI back-office systems. For residential and C&I customers with demand of less than 200 kW, AMI is being deployed through the SmartConnect program. Customers whose demand for electricity exceeds 200 kW use a system based on Real Time Energy Meters (RTEM).

Smart meters measure energy consumption at hourly or sub-hourly intervals, provide voltage readings at the customer site, and communicate with customer premise devices via a HAN.

The AMI network captures and transmits data between the meters and the AMI back-office systems. The key AMI back-office systems are the MDMS and the NMS. The MDMS is the repository for the meter and event data collected from the SmartConnect meters. This system provides the validation, editing and estimating necessary to generate a bill from the interval usage. The MDMS is also the system of record for meter read data. The NMS is the gateway to all SmartConnect meters and field infrastructure. All commands sent to, and all data received from, the meters and communications systems must pass through the NMS. Additionally, RTEMs transmit customer usage data to SCE via pager, telephone or radio, and the data from the RTEMs is processed daily via SCE's Customer Data Acquisition System (CDAS).

In addition to providing operational benefits such as reduced meter reading and field service costs, AMI provides a foundation from which several smart grid capabilities will be developed. By providing near real-time interval usage data, it facilitates enhanced DR offerings and transforms SCE's customer engagement model. AMI can also be leveraged to support discrete measurement and billing of PEV load and to enable PEV-specific rates. Finally, the smart meters will provide voltage readings critical for Advanced Volt/VAR Control and outage information that will improve SCE's Advanced Outage Management capability.

a) Baseline

Phase III of SmartConnect was approved in D.08-09-039, providing funding (through the SmartConnect Balancing Account) for the deployment of AMI infrastructure throughout SCE's territory for all customers with demand below 200 kW. SCE began deployment of SmartConnect meters in September 2009. As of December 31, 2010, SCE had installed 2,022,221[76] SmartConnect meters (95.1 percent residential, 4.9 percent small commercial) in 13 SCE districts. In addition, 1,931,402 accounts were being billed using monthly register read data collected over the air (OTA). Also, by the end of 2010, SCE had begun to bill meters using OTA interval data and will continue to transition accounts to interval data and other

76 As of May 31, 2011, 2,627,135 SmartConnect meters were installed in SCE's territory.

SmartConnect-enabled programs and services over the course of 2011.

As of December 31, 2010, 18,223 RTEMs were installed at customer locations, allowing these customer accounts to be billed using interval data.

b) Roadmap

SmartConnect deployments will continue throughout 2011 and 2012, with funding continuing to come from the SmartConnect Balancing Account. Deployment of SmartConnect meters to the five million eligible SCE customers is scheduled to be completed by the end of 2012. Forecasted costs funded through the SmartConnect balancing account are $803 million in 2011-2012. This does not include $141 million in program contingency. In addition to funding the balance of the AMI infrastructure, this will also fund Releases 1 and 2 of the ALCS (discussed in Section V.F.2.c)), development of standards for the Home Area Network, customer premise devices (Section V.F.2.b)), the Program Management Office, and O&M costs related to AMI infrastructure.

SCE customers with demand larger than 200 kW will continue to use RTEMs for the foreseeable future rather than SmartConnect meters. This is because the current version of the SmartConnect meter does not possess the functionality required to meter the large, complex metering systems that exist at most large C&I accounts that are using the RTEMs.

Both the MDMS and NMS are Commercial Off the Shelf (COTS) products supplied by a vendor. These commercial products are enhanced or upgraded by the vendor on a regular basis (12-18 month cycle). As part of the Enhanced Meter & Usage Capabilities project,[77] the first upgrade cycle for these systems is planned for third quarter 2013 and the second upgrade is planned for third quarter 2014, at a total proposed cost of $48.6 million. The rate of technology growth in these two systems will likely result in upgrades required each year for the next several years. It is expected that the CDAS will be either enhanced or integrated with MDMS in the future. The cost and scale of these upgrades are not known at this time.

2. Premise Area Network

A Premise Area Network is a HAN or similar network used in a commercial or industrial setting.

HAN refers to the ability of the smart meter to connect with devices and appliances within the home, allowing customers to receive information about electricity usage, storage, and generation within and around their home, and as a result, make informed decisions about how electricity is used and managed.

77 SCE, 2012 GRC Phase 1 Application (A.10-11-015), SCE-04, Vol. 04, p. 46.

a) Baseline

SmartConnect meters have the built-in ability to communicate with other devices within the home. However, the HAN functionality of the smart meter had not been enabled as of December 31, 2010.

b) Roadmap

Development of standards and communication protocols for the HAN will be funded by the SmartConnect program during the 2011-2014 period. In addition to smart meters, development of the envisioned functionality of the HAN requires implementation of an ALCS (discussed in V.F.2.c)) and the availability and integration of customer premise devices (discussed in V.F.2.b)).

An interim HAN solution, expected to be launched to customers during the first quarter of 2012, will test the ability of real-time usage data from the SmartConnect meter to be transmitted to and displayed on an In-Home Display (IHD). The interim solution will also include the ability to receive event notifications from the utility via the ALCS and back office systems.

The fully functional HAN, expected to be deployed in the third quarter of 2013, will add the ability to register Programmable Communicating Thermostats (PCTs) and other HAN devices to the SmartConnect Meter, enabled by Release 2 of the ALCS.

3. Customer Information Systems

SCE Customer Information Systems that support multiple smart grid capabilities (along with conventional utility functions) include the Customer Service Business Unit (CSBU) Customer Data Warehouse, the Customer Relationship Management (CRM) system, and the Customer Service System (CSS).

The CSBU Customer Data Warehouse will be responsible for storing and managing vast amounts of customer data, including interval usage data. This transactional data forms the basis for SCE's meter to cash process, and also provides data for web presentment tools and call center use.

A primary purpose of the CRM system is to manage, track, and report the company's Demand Side Management (DSM) programs, including EE and DR. The CRM also integrates with other customer systems such as SCE.com, Alerts and Notifications System, and Customer Data Warehouse.

SCE's CSS was developed in the early 1990s and performs the following six major functions: (1) Cashiering and Payment Options, (2) Credit and Collections, (3) Event Scheduling, (4) Meter Data Acquisitions, (5) Billing, and (6) Metering. All rate changes related to new time-variant and dynamic rates and DR programs require modifications to CSS.

The aforementioned Customer Information Systems are foundational investments necessary to enable the DR, Enhanced Customer Engagement, and PEV Integration capabilities of the Smart Grid.

a) Baseline

CSBU Customer Data Warehouse

As of December 31, 2010, CSBU had several stand-alone data warehouses serving various purposes. This included the SmartConnect Customer data warehouse, which stores customer usage information for billing purposes. The CSBU Customer Data Warehouse was in the planning stages.

CRM

As of December 31, 2010, SCE managed more than 75 DR and EE programs using more than 40 disparate systems, including stand-alone Access databases, Excel spreadsheets and IT supported systems. Phase I of the CRM implementation (which will integrate management of these programs) was in progress.

CSS

As of December 31, 2010, CSS was in use to produce bills for all of SCE's active rates.

b) Roadmap

Several investments in SCE's Customer Information Systems are required during 2011-2020 in order to meet the evolving needs of DR, Enhanced Customer Engagement, and PEV billing.

CSBU Customer Data Warehouse

As part of the CSBU Customer Data Warehouse[78] project, SCE plans to integrate disparate customer databases into one, centralized data warehouse that will leverage the initial platform of the data warehouse authorized in D.08-09-039 for Edison SmartConnect interval data, to improve the security, maintenance, and integrity of customer data stored throughout CSBU. The CSBU Customer Data Warehouse will provide a single source of customer data to support analytics and reporting functions, as well as the production of tools for managing customer data, including online energy management tools for customers through SCE.com. The centralized CSBU Customer Data Warehouse will be developed and implemented in 2013-2014 at an estimated cost of $26.1 million. Beyond this project, SCE plans to develop a data strategy and to implement changes that may be necessary to support the strategy considering regulatory requirements, and data security issues. This activity is projected for 2015-2017.

78 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-05, Vol. 03, p.35.

CRM

As part of the CRM[79] project, SCE will provide a comprehensive, integrated system to manage, track, and report the company's DSM programs, including EE and DR. The system will be used for interactions with SCE's vendors who help deliver the DSM programs, including verification of program eligibility and application processing, vendor contract management, and incentive payment processing for vendors and customers. This will provide integration across the company to improve the overall controls and management of these programs. The CRM system will also provide a significant tool for designing and developing specific programs for customers based on each customer's past history, location, size, usage and other key customer criteria. It will maintain key customer contact information and program specific status information such as program delivery dates, and tracking status through enrollment.

The CRM project will be implemented in two phases. The first phase, which will implement the centralized system for managing DSM programs, will be in operation in the second quarter 2011. The second phase will install vendor supplied upgrades to allow for greater automation in the enrollment process and to implement e-channel capability will be completed in the first quarter 2013. The total cost from 2011-2014 is forecast to be $40.6 million. No work beyond normal maintenance is expected until 2018 when the vendor supplying the software is expected to issue a major upgrade. This work will be planned over three years and will occur in the 2018-2020 timeframe.

CSS

SCE plans to upgrade its CSS.[80] CSS was first developed in the early 1990s and SCE currently anticipates replacing it in 2017. In order to continue to operate CSS until 2017, changes will be made to billing, credit & collections, meter equipment systems, account management information, accounts receivable and interfaces with the field service functions. These changes will replace the obsolete portions of the application and will make significant upgrades to improve the flexibility to easily implement new rate changes and to support new United States Postal Service (USPS) address standard requirements.

The total cost from 2012-2014 is forecast to be $42.2 million. In the 2015-2017 timeframe, further enhancements are planned for the billing, accounts receivable, collections and customer account management areas. A greater integration with SCE's financial systems is also planned. A decision to entirely replace the CSS with a vendor supplied integrated system will be addressed early in this time period and will significantly impact plans for the 2016-2020 time period.

79 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-04, Vol. 04, p.36.
80 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-05, Vol. 03, p.45.

c) Capability-Specific Deployments

In addition to the platform-based projects discussed above, changes to SCE's Customer Information Systems are planned to meet specific smart grid capabilities. These projects will be discussed in the Customer Empowerment roadmap section, and include the Dynamic Pricing Project, Alerts and Notifications Project, PEV Support Systems, and HAN Support and Troubleshooting.

4. SCE.com

SCE.com is the primary website for SCE customers to conduct business with SCE over the internet. The website was deployed nearly 10 years ago and was primarily intended to serve as an online information source for customers, providing details about SCE's rates, programs, and services. Over time, the site grew to have more "transactional" capabilities that allow for customers to view their electricity usage, display and print bills, and make payments.

In the future SCE.com will become a fundamental piece of the platform that will empower customers to manage their energy usage, supporting smart grid capabilities such as DR, Enhanced Customer Engagement, and PEV Integration.

a) Baseline

As of December 31, 2010, SCE.com was capable of presenting interval data from SmartConnect meters. However, interval data will not be available online for customers until 2011. SCE.com also included the Bill-to-Date, Bill Forecast, and Budget Assistant energy management tools. Bill-to-Date provides a customer with an estimate of their bill to date in the current bill period. Bill Forecast estimates what a customer's bill will be at the end of the current billing period based on his or her average daily usage to date in the period. Budget Assistant allows a customer to set a target energy bill cost for the month and allows them to receive periodic notifications on how they are progressing toward the target or as certain pre-designated thresholds are crossed. SCE.com also provides information to customers about rates, DR programs, and EE programs.

As of December 31, 2010, a project was underway to replace SCE.com with a new platform in order to address obsolescence issues and support the changing business needs of SCE and its customers. This project is described in the roadmap below.

b) Roadmap

With the deployment of smart meters, SCE's customers have access to interval usage data and can enroll in various dynamic rates that offer benefits when customers actively manage their energy usage. For this to be successful, SCE must provide adequate means for its customers to take full advantage of the capabilities enabled by SmartConnect to manage their energy usage. To meet the increased requirement, the SCE.com[81] project will upgrade the SCE.com website to enable customers to gather information online about various smart grid enabled rates and programs, enroll in those rates and programs, and monitor and evaluate energy usage data and costs. Moreover, SCE plans to utilize SCE.com as a fully viable self-service channel for many routine customer interactions. By empowering customers to employ self-service on the web, SCE seeks to reduce the number of routine transactions through its phone centers so that call center representatives can meet the anticipated need for consultative interactions with customers on the new and more complex technologies and rates, including questions on dynamic rates, HAN functionality and devices, and matters related to PEVs.

SCE also anticipates that as customers become more technically sophisticated with information regarding their energy bills, they will increasingly utilize SCE.com to obtain more sophisticated information regarding their energy usage and costs, including receiving and reviewing their bills, projecting costs of future bills, and utilizing online tools to monitor and evaluate energy consumption. Additionally, SCE will provide an online capability for customers with smart meters to estimate their bill impact from the rates for which they are eligible based on their historical interval usage. The work described in this section is scheduled for deployment from 2010-2014, with a total estimated cost during the 2011-2014 period of $54.6 million.

It is currently projected that little work will be required beyond normal maintenance from 2015-2017. However, a major upgrade may be required in the years 2018-2020.

5. Field Area Network

The term FAN encompasses several different existing and planned networks (wired and wireless) used by SCE for communication between field devices and management systems.

The Itron OpenWay AMI network, an important network that connects smart meters with the AMI back office systems, was discussed above as part of broader discussion of the AMI.

81 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-05, Vol. 03, p.46.

The Mobile Radio network is an important existing field area network that provides voice communications in support of field personnel engaged in daily operations, new construction, and emergency response. In addition to supporting operations and ensuring the safety of field personnel, the mobile radio network is key component of the Workforce Automation capability.

In addition, SCE operates its Utilinet radio system which is a 900 MHz wireless network that provides communications for a variety of purposes on SCE's distribution system. This network will become even more critical in the near future as tens of thousands of intelligent field devices are installed on the distribution system. A new generation of this FAN, called the 4G Wireless Network, will be needed to meet the future state vision of DER Integration, AV/VC, Advanced Outage Management, and Advanced Asset Management. This network will be faster than the current Utilinet system, with higher bandwidth and lower latency.

a) Baseline

The current Mobile Radio system is an analog-based network implemented in 1994-95. It is used for a variety of tasks, including dispatch of personnel to restore electric service, to address dangerous electrical situations especially during storms and emergencies, and to activate new service to SCE's customers. It is also critical for the crews' safety when they work in many remote areas where no other means of communication exists.

Approximately 3,400 portable (hand held units) and 900 mobile (truck mounted) units were used by SCE personnel performing diverse jobs. With the system facing obsolescence, critical components were recently upgraded in order to extend vendor support to 2015.

Currently, SCE's Utilinet FAN consists of a NETCOMM radio communication system where each automation distribution device (e.g. remote controlled switches, programmable capacitor controls) is equipped with one radio to enable remote monitoring and control. In addition, the Metricom Communication Concentrators (MCCs) aggregate the data from the radios for transmittal to back offices systems. More specifically, this radio network (1) transmits data collected by automation devices back to SCE internal systems, and (2) transmits operational commands back out to the devices in the field. In addition to supporting distribution automation, this network also connects to meters of large C&I customers.

As of December 31, 2010, there were approximately 50,000 NETCOMM radios in the field, and 110 Metricom Communication Concentrators (MCCs).

b) Roadmap

As part of the Mobile Radio System Replacement[82] Project, the aging mobile analog system will be replaced with a Private Digital Trunked Radio System. This will involve a change out of the existing analog equipment to digital, but SCE's existing towers, antenna, and spectrum can be reused with no significant operational adjustments. In order to complete the upgrade before 2015, work must begin in 2012. Total estimated cost of this project is $30 million. The upgrade will ensure that worker safety is not put into risk by an obsolete analog system.

The Utilinet FAN is being expanded as part of the Distribution System Efficiency Enhancement Project (DSEEP),[83] in which SCE will deploy approximately 2,900 new radios annually from 2011 to 2014 for new distribution automation devices, infrastructure network support, and the replacement of obsolete radios. At a cost per radio of $1,674 in 2009 dollars, the total cost of these deployments is estimated to be $21.3 million from 2011 to 2014.

As more distribution support devices are installed and new, advanced functionalities require higher bandwidth and faster throughput, SCE plans to deploy a 4G wireless broadband communication network with high-speed connectivity that will eventually replace the existing Utilinet network. This 4G network may also be able to support the AMI back-haul network, which is currently leased from AT&T and Verizon. As the technology is not yet mature, the timing and cost of rolling out the 4G network are unknown at this time. Deployment is not likely to begin until 2015 at the earliest, and will take several years to complete.

As the two networks may run in parallel for some time, deployment of NETCOMM radios may continue during the 2015-2020 time period, at a minimum to replace obsolete or failed radios and to account for growth in the distribution system.

6. Substation LAN

At one time, virtually all of the substations in SCE's distribution system had to be operated by field personnel, many around the clock. As technology became available, SCE began to install different types of control systems, with each new generation providing greater capabilities of remote control, data acquisition, and automatic response. Substations upgraded under existing programs have allowed SCE to reduce the number of personnel required to operate substations, while simultaneously maintaining the appropriate level of service to customers. In the future, the Substation LAN will also contribute to advanced Smart Grid capabilities such as DER Integration, Advanced Volt/VAR Control, Advanced Outage Management, WAMPAC, and Advanced Equipment Monitoring as discussed earlier in this document.

82 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-05, Vol 02, p. 145.
83 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-03, Vol 02, p. 47.

a) Baseline

SCE has a total of 928 substations in its service territory, 687 of which are SCE owned and operated (59 A/AA and 628 B substations),[84] with the remaining 242 built to serve specific customers. SCE has been deploying networked substation automation for 14 years. SCE's first substation automation design standard, Substation Automation System (SAS), was a proprietary standard. SAS evolved into a somewhat more open standard called Substation Automation-2 (SA-2), which is in use today. SA-2 integrates Supervisory Control and Data Acquisition (SCADA) networks, back-office systems, and substation equipment to enable automated operations, remote control and monitoring. Prior to SAS, some substations were equipped with Remote Terminal Unit (RTU) / Programmable Logic Controller (PLC) devices, which provided automated operations and remote control. This design was very labor intensive as the components were hard wire connected versus the SAS which is a LAN connected design. As of December 31, 2010, approximately 220 substations had RTU/PLC devices, and approximately 350 were equipped with either SAS or SA-2. Therefore 51 percent of SCE-owned and operated substations had SAS or SA-2, and 90 percent had different technologies for automation and remote control and monitoring.

b) Roadmap

The next generation of Substation Automation is called Substation Automation-3 (SA-3). Adopting SA-3, SCE will replace and upgrade substation networking and communication equipment to support the International Electrotechnical Commission (IEC) 61850 communications protocol.[85] This protocol will become the industry standard for distribution and substation automation, and will be critical in bringing about a completely automated distribution system.[86]

The new substation automation program will allow SCE to integrate substation automation with its distribution automation programs. It will also provide SCE with more flexibility in procuring the best substation equipment by moving to an open, non-proprietary communications standard. Finally, SA-3 provides a comprehensive automation solution that will be fully compliant with upcoming changes to the NERC's Critical Infrastructure Protection Standards.

As part of SCE's Substation Automation Integrating IEC 61850[87] limited deployment project, SA-3 technology will be installed on 19 B substations and 3 A/AA substations during the 2012-2014 time period. The total cost of this project is forecast as $18 million.

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84 AA substations connect SCE's 500 kV transmission system with its 220 kV transmission system. A substations connect SCE's 220-115 kV transmission system and subtransmission system with its 115/66 kV subtransmission system. B substations connect SCE's 115/66 kV subtransmission system with its 16/12 kV distribution system.

85 This standard is available from the IEC at http://webstore.iec.ch/webstore/webstore.nsf/artnum/033549.

86 This standard is available from the IEC at http://webstore.iec.ch/webstore/webstore.nsf/artnum/033549.

87 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-03, Vol. 02, p. 60.

Throughout the 2011-2014 period, replacements of obsolete SAS systems with SA-2 will continue as part of the SAS System Replacements[88] project. Between 2011 and 2014 obsolete SAS systems will be upgraded to SA-2 on approximately 61 distribution substations. Estimated total cost is $16.9 million, based on $259,000 per substation in 2011 dollars.

SCE expects that by 2015 SA-3 will become the standard and SA-2 will no longer be deployed. SCE would then continue to deploy SA-3 until all distribution substations are equipped. The pace of deployment is uncertain, given resource and funding constraints. The unit cost is also uncertain, as SA-3 is a relatively new technology. Given these uncertainties, total 2015-2020 cost for SA-3 deployments is expected to fall within the range of $60 to $159 million.

7. High Speed Backbone Network

SCE's High Speed Backbone Network is a fiber optic and microwave telecommunications network that connects substations and transmission-level devices with SCE's back-end systems. This network will become even more critical in coming years with the additional data generated by advanced applications such as C-RAS, PMUs, and Substation Automation.

a) Baseline

SCE's current high-speed backbone network, known as SCEnet, was built out between 1994 and 1997. SCEnet has served SCE well over the years, but SCE must now address the communication network's obsolescence, new capacity demands, and new connections to remote locations outside of the current network. For example, new renewable energy power plants in the desert require communication circuits to help protect and manage power lines in the eastern portion of SCE's service territory. These regions had been effectively served by low bandwidth, high latency copper and legacy (analog) microwave circuits but now need high bandwidth, low latency communication circuits. The largest limitations of the current network architecture include (1) the inability to scale while also supporting multiple separate networks expected in the future, (2) the inability to accommodate the expected explosive growth in bandwidth in the remote areas of the network, and (3) the inability to manage great variability in latency, performance and security requirements between different applications.

88 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-03, Vol. 03, p. 84.

b) Roadmap

As part of SCE's Next Generation Network - SCEnet II project, SCE is beginning the planning and deployment of the next generation of high speed backbone (SCEnet II) network to address the aforementioned limitations of the existing SCEnet and accommodate demanding smart grid applications such as C-RAS, PMU enabled monitoring and control, and SA-3.

During the 2012-2014 period, SCE will undertake a range of SCEnet activities. It will extend IP connectivity by installing approximately 1,000 miles of fiber optic cable to reach 121 SCE 69 kilovolt (kV) and 115 kV substations in support of substation automation and other smart grid applications. This project consists of installation of fiber optic cable, lightwave terminal equipment, routers/switches, and common equipment such as alarms and maintenance access switches. While fiber optic cable is the standard for SCEnet II, digital microwave will be used where permitting issues, long distances, inability to obtain rights of way, or other factors make fiber impractical to install. The second major activity will be the re-architecture of SCEnet into SCEnet II, which will support logical separation of multiple networks, low latency demanding applications, and applications with bursty and variable bandwidth requirements. Other initiatives and programs may also leverage the bandwidth available on the fiber cable for applications such as security video surveillance, broadband wireless connectivity to the field forces and data back haul for Smart Connect. The total cost for this project is expected to be $75 million from 2012-2014.

The SCEnet II project is expected to continue through the 2015 rate cycle. Given uncertainties in scope of this continuation of SCEnet II deployment, estimated costs are expected to fall within the range of $50 to $132 million.

8. Distribution Management System

The DMS is the centralized computing system that allows SCE to gather data from various distribution automation programs and automate operation and control of the distribution system as a whole. As more and more field devices (e.g. switches, capacitors, relays, substation equipment) become equipped with communications and automated control and operational capabilities, a central DMS system that integrates operation of these devices becomes increasingly critical to achievement of a smarter grid. The contribution of the DMS to specific smart grid capabilities is discussed in later sections of this document.

a) Baseline

SCE's current DMS is an "in-house," Windows-based system, used by operators to remotely control and monitor distribution devices such as switches, reclosers, capacitor banks, etc. As an example of how the system operates, assume that a distribution circuit is de-energized due to a fault on the circuit. The

automated switches opereate in conjunction with the substation automation till the fault is isolated. The operator then needs to use the DMS to remotely operate other switches to restore service to the rest of the customers. Information about the status of that circuit and all of the other circuits in the area is collected from field devices by the DMS. This information is then presented to system operators in one of SCE's 14 Switching Centers. Operators in these switching centers can then issue commands back through the DMS to reenergize circuits, as appropriate, by opening and closing automated distribution switches. As of 2010, this system faced software obsolescence, insufficient data management capability, limited automation, and no advanced distribution grid control and analysis applications.

b) Roadmap

SCE plans to upgrade and enhance its DMS as part of the Distribution Management System project.[89] The future DMS will be a "commercial, off-the-shelf" solution with full support for required fixes and future upgrades. This system will be designed to handle all new automated devices and advanced technologies planned for SCE's future smart grid deployments, while providing enhanced data analytics and control capabilities with integrated security. Furthermore, this DMS upgrade will enable AV/VC in two phases. After the first phase, DMS will have the basic functionality required for remote control and monitoring of capacitor banks. At the end of the second phase, DMS will be equipped with the software and enhancements required to implement AV/VC, which will first be piloted on select substations and then rolled out to all automated substations. Total forecasted costs to upgrade the DMS in the 2011-2013 period include $27 million for capital software, and $2.9 million in related O&M costs.[90] Future upgrades may be required during 2015-2020.

9. Outage Management System

The TDBU Outage Management System (OMS) is a critical system used by the TDBU Grid Operations Department to monitor and identify customer outages on SCE's distribution network. The system provides critical information for the identification and restoration of electrical service outages. Without this system, the amount of time required to identify customer outages and restore service for SCE's customers would increase dramatically.

a) Baseline

Leveraging the AMI infrastructure deployed through the SmartConnect program, information about the status and duration of outages at a specific customer location is greatly enhanced through a process called a load side voltage (LSV) check.

89 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-03, Vol. 02, p.65, and SCE-05, Vol. 03, p. 97.
90 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-03, Vol. 05, p. 45.

The OMS application itself was last updated in 2007-2008. As of December 31, 2010 it had known defects and experienced occasional maintenance-related outages, which negatively impact operations and service restoration, interfaced systems, and users' productivity.

b) Roadmap

As part of the Outage Information project[91] SCE will add the following functionality to the OMS:

1. SmartConnect Diagnostic API - A shared application programming interface (API) that will allow OMS, CSBU CSS, and other SCE systems to run diagnostics within the SmartConnect/Itron AMI system by developing a customized web service for each SCE system.
2. Customer Meter Query - A database communication package to allow the TDBU OMS structure and customer information database to query the CSS SmartConnect meter ID information database.
3. VRU Presentation Layer - A new presentation layer for the CSS Voice Response Unit (VRU) enabling the customer interface to run automated SmartConnect AMI diagnostics to assist CSBU representatives in diagnosing service outage problems.

Total cost for these system enhancements are estimated at $3 million in 2013-2014. More system enhancements may be necessary, but scope and costs cannot be determined at this time.

In addition, the OMS application is scheduled for upgrades for 2012 and 2014 to address the defects discussed above. This will be done as part of the Outage Management System project, at a cost of $4.3 million.[92] A more expansive upgrade of SCE's Outage Management System may take place in the 2015-2020 time period as well.

10. Geographical Information System

SCE's Geographical Information System (GIS) will act as a comprehensive data repository that stores information regarding the physical, electrical, and spatial attributes of all transmission and distribution assets while allowing end-users to access this information from one reliable source. SCE's GIS will be supported by a computer-based geographic mapping software application that allows users to selectively overlay information about a utility's electrical system assets on a graphically-displayed map. This comprehensive mapping system will store and manage four primary categories of vital information about an asset:

91 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-03, Vol. 02, p. 71.
92 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-05, Vol. 03, p. 87.

- Geographic location;
- Site-specific conditions;
- Physical characteristics of the asset; and
- Electrical connectivity.

Having this comprehensive data repository in place will generate benefits such as employee and public safety, improved inspection compliance (GO 165), improved prioritization of maintenance work, and improved reliability. In addition, GIS will contribute to the development of smart grid capabilities such as Advanced Outage Management, Wide Area Monitoring, Advanced Equipment Monitoring, Workforce Automation, and DR, as discussed earlier.

a) Baseline

SCE's GIS applications were developed roughly 10 years ago and no major upgrades had been completed prior to 2010. As of December 31, 2010, SCE had multiple asset data repositories, multiple landbases on which the asset data is viewed, and cumbersome processes and procedures required to process this disparate data. Over the years, various departments within SCE developed independent systems to meet their specific needs. As a result, asset data including geographic location, site-specific conditions, physical characteristics, and electrical connectivity were incorporated in disparate and often times non-interoperable systems. Source systems often used different landbases to display their data, lacked critical spatial and electrical information, and provided graphical information that required significant manipulation by the user and could not be aligned across several systems. Data source inconsistencies can impact field work; confusion or lack of accuracy can compromise safety and reliability.

b) Roadmap

As part of the Comprehensive TDBU Geographical Information System (GIS) project,[93] SCE is planning to implement GIS to make consistent, accurate, and consolidated asset data available to all appropriate users through integration of previously disparate systems with incompatible data. The GIS will store and facilitate access to detailed and standardized asset information (including smart meters), end-to-end electric connectivity information, and supporting data from the U.S. Geological Survey, forestry departments, and weather service organizations. The GIS Application System will be enhanced with software upgrades, additional hardware, specialized tools, GIS-specific appliances, storage media and third party data layers and aerial photography. New GIS architecture will provide visualization tools for field personnel and allow multiple-user access to current data such as electric infrastructure assets, base maps, aerial imagery, and GPS coordinates.

93 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-03, Vol. 05, p. 7.

GIS deployment will begin with data consolidation activities. SCE will host the consolidated data in a GIS database, where it will be used by multiple TDBU users. The GIS database will require hardware components, including servers, storage, and supporting tools necessary for the production database as well as development, testing, and training environments. Software tools and integration components will be acquired and implemented so that consolidated asset data hosted on SCE hardware can be accessed through multiple applications including Graphical Design Tools, Scheduling Software, OMS, Consolidated Mobile System, and Enterprise Resource Planning (ERP) system. Estimated costs during the 2011-2014 time period include $45.8 million in capital to deploy the integrated GIS system, $22.8 million in related O&M deployment costs, and $2.2 million in capital for routine software refreshes[94].

11. Workforce Computing Devices

Workforce computing devices include ruggedized portable laptop computers, ruggedized handheld computers, and automated vehicle location devices, all incorporating a Global Positioning System. Such devices can enable field personnel, system operators, and office workers to share real-time information that will enhance SCE's safety, improve outage responsiveness, contribute to SCE meeting its compliance obligations, and improve workforce productivity. These tools form a key part of the Workforce Automation capability.

a) Baseline

As of December 31, 2010, the transfer of information between field workers and the office was not fully automated. Field tools were used by only a limited segment of SCE's field personnel. For those field employees without field tools, the time required to physically move paper documents can delay the interchange of data between the field and back office computer systems, which causes the information to be inconsistent, at least temporarily, with actual conditions in the field. In addition, the effort required for field crew members to manually record detailed information about electrical assets limits the amount of critical data that will be recorded by field crews, further reducing the ability for maps to portray actual field conditions.

b) Roadmap

The Consolidated Mobile Solutions (CMS)[95] project will expand distribution of mobile technology among field employees, so that every field employee who could benefit from a field tool will have one. In

94 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-05, Vol. 03, p. 85.
95 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-03, Vol. 05, p. 21.

addition, existing tools will be upgraded with new capabilities in mapping, navigation and vehicle tracking, in one vendor-supported application. Accompanying the integrated mobile application, SCE will acquire, test, and deploy the required IT infrastructure (such as additional servers and system interfaces), along with all user hardware devices (ruggedized laptops, handheld computers, automated vehicle location devices), required for a user base of 2,500 or more users to simultaneously pass real-time information between the remote mobile application and supporting office systems such as ERP, GIS, and Outage Management.

Costs of this deployment project are expected to total $15.8 million in capital and $1.6 million in related O&M costs from 2011-2014.

12. Energy Management System

The EMS serves as the primary tool used by grid operators to monitor and control the transmission system. It plays a key role in maintaining reliability, safety, and efficiency in managing the power grid. It is an essential piece that will allow for advanced smart grid capabilities such as WAMPAC, and Advanced Equipment Monitoring.

a) Baseline

SCE uses the existing EMS to monitor and control thousands of electrical data points on the transmission grid. The EMS provides system operators the ability to manage the transmission grid at fourteen geographically dispersed operational centers (Switching Centers) with the real-time capability of: remotely opening or closing circuit breakers (commonly called "switching"), monitoring and controlling substation equipment power flows, monitoring and controlling transmission line power flows, and generally ascertaining the conditions of the transmission grid.

b) Roadmap

The EMS as it exists today has the capability to support and integrate advanced smart grid capabilities. However, refreshes will be necessary to upgrade to the latest versions of the software, re-platform the system onto the same technology base as the new DMS/ALCS, and generally avoid technology obsolescence. As part of SCE's Energy Management System Upgrade project,[96] an upgrade is scheduled for 2011 consisting of Evergreen hardware and software improvements and updated software issued by the supplier. This upgrade will cost an estimated $5 million. Similar upgrades will occur approximately every 5 years. SCE expects costs in the range of $3 to $7 million during 2015-2020.

96 SCE's 2009 GRC, SCE-03, Vol 3, Pt 5, p. 33.

13. Smart Grid Cyber Security[97]

SCE considers cyber security a foundational element of the design of each piece of equipment that it deploys. In the period covered by the Deployment Plan and beyond, SCE will equip an unprecedented number of field devices with communications capabilities. In addition, utilities across the nation and particularly in the WECC will deploy their own smart grid systems and SCE will likely be connecting to those smart grid systems. The devices within these interconnected systems will transmit information about the status of transmission and distribution systems from the field to SCE's system operators, and system operators and control systems will make real-time decisions based on this information.

The cyber security risk that will grow as SCE and other electric utilities deploy these smart grid systems is a main driver of SCE's focus on cyber security. Cyber security elements will be built into these devices and systems as they are deployed in the field. In addition, to effectively manage cyber security of these disparate and varied devices and the systems that serve them, SCE will invest in systems that provide centralized integration, coordination and monitoring of the cyber security elements of the thousands of smart devices that will be deployed across SCE's transmission and distribution systems. SCE therefore considers appropriate cyber security protections a necessary element of every piece of infrastructure it deploys.

a) Baseline

A discussion of SCE's existing cyber security practices is provided in Chapter VIII.

b) Roadmap

SCE's Smart Grid Cyber Security program is a centralized, comprehensive solution designed to manage new threats posed by smart grid deployments. It will include the information technology (IT) equipment and software needed to ensure the security of communications to, from and between all smart-grid related systems and devices. Centralized cyber security services will be built into all smart grid information systems based on the function, architecture and sensitivity of the data they transmit.

As part of the Smart Grid Cyber Security project[98], SCE will deploy centralized IT smart grid security capabilities to enhance protection of back office systems and ensure secure communication with field devices deployed under other smart grid programs. This project entails five key cyber security elements:

97 SCE's Grid and Cyber Security Strategy is discussed in more detail in Chapter VIII.
98 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-03, Vol 02, p. 98.

- Key Management Services - Each smart grid device deployed on SCE's system has a unique key that allows for recognition and verification of that device before initiating secure communication with SCE's back office systems. The Key Management Services equipment and software that will be procured as part of this Smart Grid Cyber Security program will track, organize, and verify keys for each device on SCE's system. The tools will also provide a mechanism for authenticating keys once equipment is placed in service, and will update keys as necessary to ensure the continued security of communications within SCE's smart grid systems.

- Cryptographic Services – While Key Management Services provide the mechanism for securely initiating communications between and within smart grid systems, cryptographic services encrypt and decrypt the information that is actually exchanged.

- Security Configuration Management – Security Configuration Management sets the overall rules and settings for devices across the system. These rules and settings include the required level of security for each device based on its function (i.e., whether the device is a control device, a measurement device, or safety equipment). This element of the smart grid cyber security program also allows SCE to control which personnel are able to access which devices. Moreover, Security Configuration Management allows SCE to filter out corrupted data that pose a significant threat to the integrity of SCE's communications and information systems.

- Audit and Reporting Management – This sub-project provides a system "check" to determine whether any aspect of SCE's smart grid systems have been compromised at any given time. The functions here include levels of alert based on how serious the possible threat appears to be. Audit and Reporting Management also provides the capabilities for generating the audit reports.

- Security Integration – The centralized cyber security services provided under this program must be integrated with SCE's other operating systems. Those other operating systems include the DMS, the EMS, and other similar systems. This integration will require that we refine systems to permit seamless integration; this sub-project will cover the costs of those refinements.

Total cost of the cyber security project is estimated to be $28 million from 2012-2014. The scope of SCE's work beyond this period will depend on a number of factors including the pace of smart grid infrastructure deployment, evolving standards and the emergence of cyber security threats. SCE expects to provide more details about future cyber security deployments in future Deployment Plan updates.

14. Summary

Figure 22 and Figure 23 on the following pages summarize the baseline status of the infrastructure elements described above, planned deployments of this infrastructure between 2011 and 2020, and the future state vision for each of these infrastructure elements.

Figure 22 – Platform Infrastructure Baseline and Roadmap Summary (1 of 2)

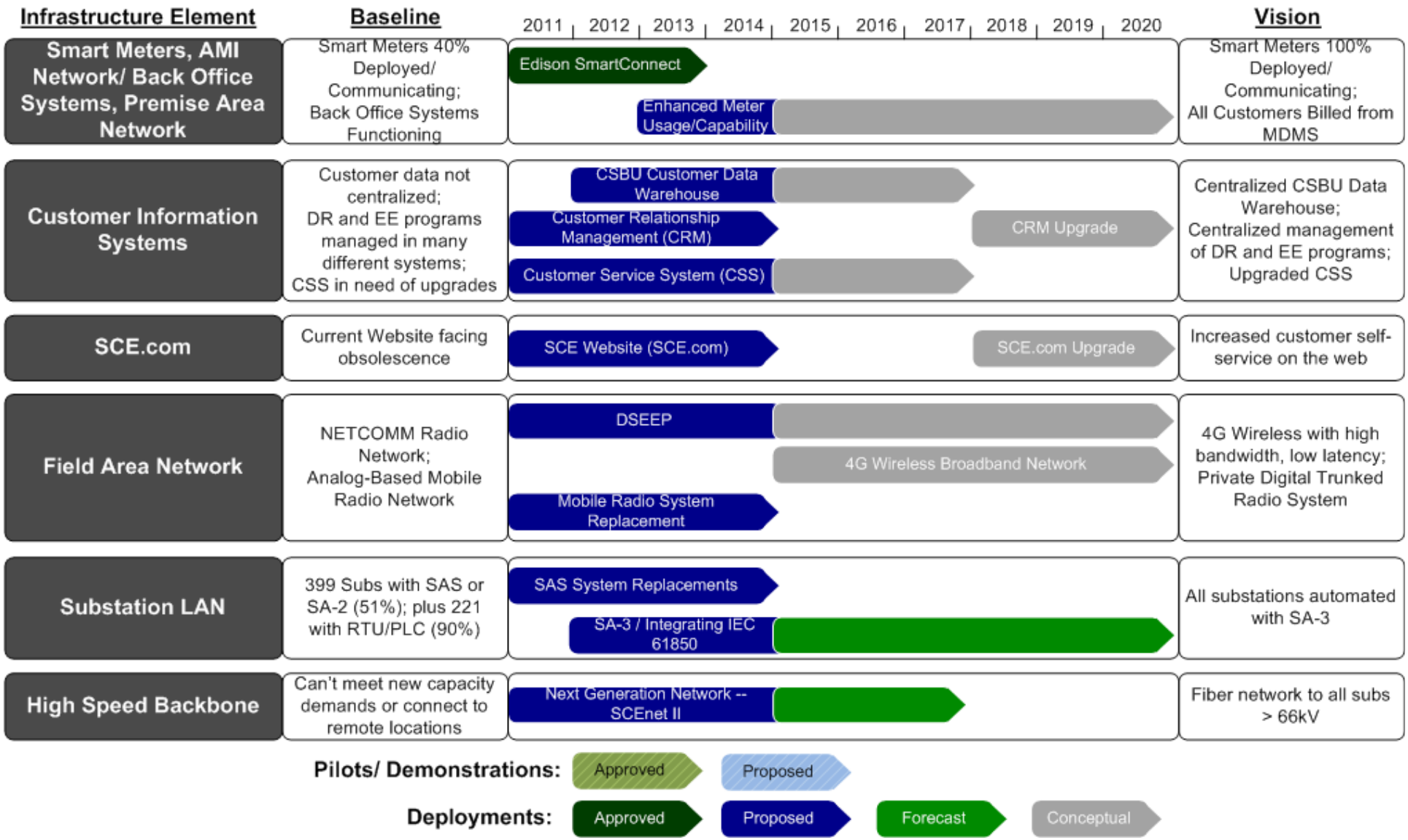
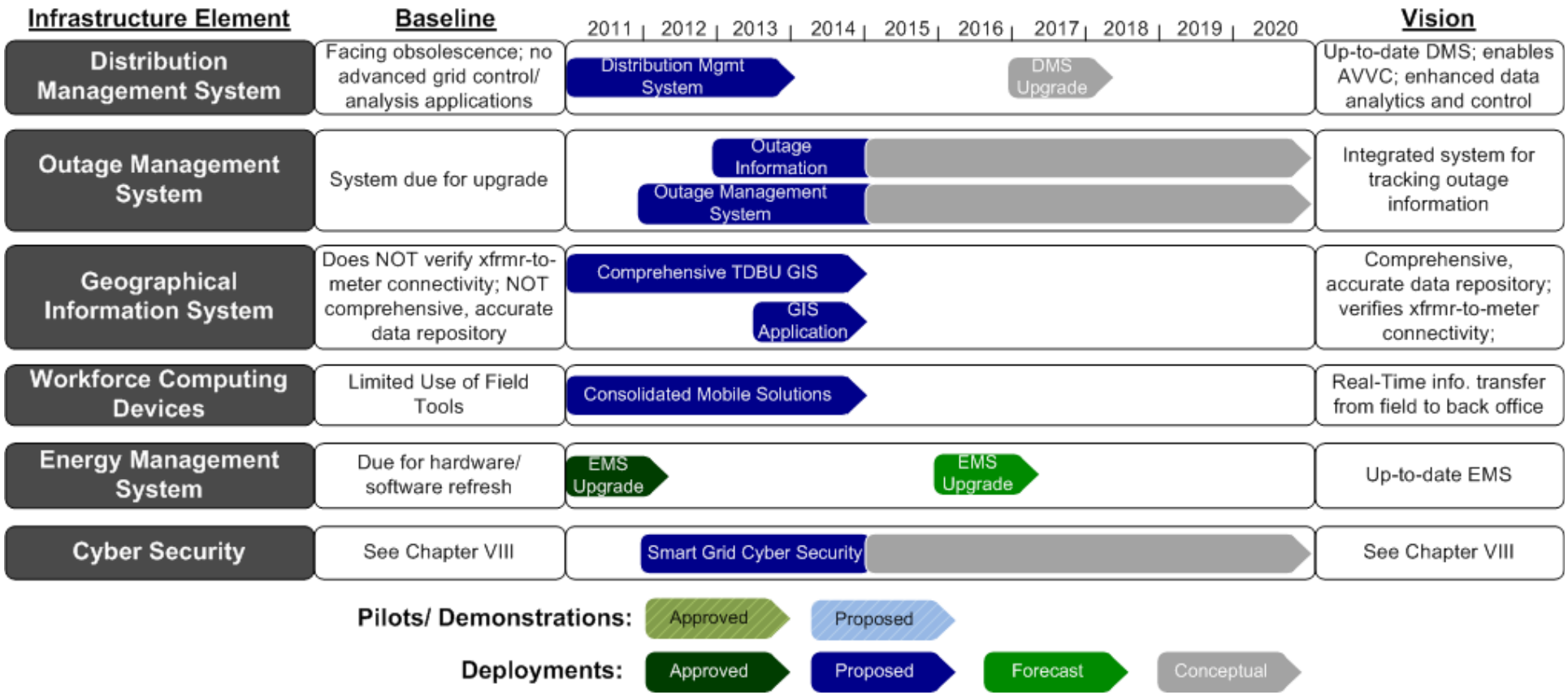


Figure 23 – Platform Infrastructure Baseline and Roadmap Summary (2 of 2)



F. Customer Empowerment Baseline and Roadmap

As discussed above, the smart grid capabilities in the Customer Empowerment domain – DR, PEV Integration, and Enhanced Customer Engagement – will empower customers to take a more active role in managing their energy use. The sections below present a baseline of these capabilities, followed by a roadmap that describes SCE's plans to deploy infrastructure that will enhance its ability to deliver these capabilities in the future.

In addition to the baseline information provided below, SCE has addressed the questions in D. 10-06-047 related to its baseline practices with respect to the customer data that will be produced as capabilities in this domain develop. SCE's responses to these questions are included in Appendix A.

1. Baseline

The sections below describe the baseline state of each capability in the Customer Empowerment domain.

a) Demand Response

Interval metering is a key technology for enabling several of SCE's DR programs, either through recording of interval usage data for dynamic pricing rates or performance based measurement of load reductions during DR events. Large C&I customers have benefited from DR programs enabled by interval meters (specifically, RTEM meters) for several years. SCE's largest customers (demand ≥500 kW) have had interval meters and mandatory TOU pricing for over 25 years. Other large C&I customers, with demand of 200 kW or more but less than 500 kW, have had interval meters and mandatory TOU rates for more than six years. As a result, many of SCE's DR participants, outside of the Summer Discount Plan (SDP) air conditioner cycling program, are large C&I customers.

As of December 31, 2010, SCE had nearly 7,000 customers enrolled in price responsive DR programs with a potential for approximately 215 MW in load reduction. SCE's price responsive DR programs include: Critical Peak Pricing (CPP), Real-Time Pricing (RTP), Demand Bidding Program (DBP), Capacity Bidding Program (CBP), and Demand Response Contracts (DRC).[99] Of the potential 215 MW of price-responsive load reduction, 34 MW was automated through SCE's AutoDR program, with another 75 MW in progress at the end of 2010. SCE also offers the AutoDR Platform, known as the Demand Response Automation Server (DRAS), which communicates via secure internet protocols to automated devices and energy

99 More details about SCE's DR programs are available in SCE's Demand Response Program Guide: https://portal.edisonintl.com/irj/go/km/docs/sce/CSBU/Business%20Area/Tools%20%26%20Resources/Information%20Centers/Account%20Management%20Information%20System%20(AMIS)/Categories/D/Demand%20Response%20-%20General/Demand%20Response%20Programs%20Guide%20August%202010.pdf.

management systems. This system supports the aforementioned CPP, RTP, DBP, CBP, and DRC programs and communicates via email and text message/SMS to program participants. The software communicates via the OpenADR standard and the dispatch application is managed for SCE, PG&E, and SDG&E by a single vendor.

In terms of reliability DR programs, as of December 31, 2010, SCE had almost 1,500 non-residential customers enrolled in either the Agriculture & Pumping Interruptible Program or the Base Interruptible Program resulting in a total load reduction of almost 750 MW for the two programs. More than 340,000 customers participated in SCE's SDP in 2010, providing approximately 570 MW of direct load control through radio-enabled switches installed on customers' air conditioners. Also for reliability, SCE leverages its Alhambra Control Platform system (ACP) to dispatch load relief when called upon by the CAISO. The ACP has been in existence for more than 20 years and can dispatch approximately 1,300 MW in curtailable load in less than 30 minutes.

While many of the DR programs discussed in this section have been available to larger customers for many years, SCE's in-progress SmartConnect deployment (details discussed in Section V.E.1) will make many of these DR programs more accessible for residential, small / medium C&I, and small / medium agriculture & pumping customers.

Also, as of December 31, 2010, the ALCS system and HAN had not yet been enabled. These infrastructure elements will provide important functionality enabling device registration, load control dispatch and communication, and information provisioning needed to facilitate participation in certain DR programs and rates.

b) PEV Integration

For many years, SCE has offered metering arrangements that allow for discrete and/or TOU measurement of PEV load. For today's residential customers, SCE provides the option of two PEV specific time-of-use rates: TOU-EV-1 and TOU-D-TEV. The TOU-EV-1 tariff allows EV load to be separately metered from the remaining house load. This rate option offers the lowest off-peak charging rate but requires the installation of a separate IDR or SmartConnect meter[100] specifically designated for EV usage. The latter TOU-D-TEV rate is a "whole house" (single meter) option providing low off-peak charging rates without the additional cost and time associated with installing a second PEV dedicated meter. SCE also offers sub-metered or individually metered configurations for commercial and public charging facilities under existing tariffs

100 SCE has historically installed interval data recording (IDR) meters to support time-of-use metering of PEV load. As SCE completes its ongoing SmartConnect deployment, a new AMI meter will be installed for both TOU-EV-1 and TOU-D-TEV rate options.

TOU-EV-3 and TOU-EV-4.[101] SCE does not yet offer any PEV load management programs, although it is currently filing for pilot funding.

SCE has performed extensive customer engagement to support the safe, reliable adoption of PEVs. With regard to PEV Integration, SCE has largely enhanced its online presence to provide PEV-related education and outreach so that customers can streamline the installation of metering or EVSE hardware and select a tariff that best suits their charging preferences. In 2009, SCE launched a dedicated web-page on SCE.com designed to familiarize customers with the processes required for charging and integration of PEVs (www.sce.com/pev). The webpage informs customers about their charging options and provides critical information needed for permitting of electrical work, city inspection, and charging circuit requirements. An automated PEV Rate Assistant Tool will take inputs such as vehicle type, typical power usage, expected miles per year, and anticipated charging times to automatically recommend a rate that maximizes customer savings. The information and tools provided through SCE.com will support PEV Integration by optimizing the customer experience associated with the installation of charging infrastructure and the selection of desired time-variant rates or future PEV load management programs.

c) Enhanced Customer Engagement

The development of this capability depends on the availability of interval usage data from smart meters, with day-after usage data delivered over the internet and near real-time usage data delivered through a HAN to devices located on customer premises.

As of December 31, 2010, SCE had deployed 2,022,221 SmartConnect meters for customers with demands less than 200 kW. The meters were being read for monthly read over the air (OTA), allowing OTA billing for 1,931,402 customer accounts. However, none of these accounts had yet been billed using interval data, and therefore customers did not yet have access to interval usage data through SCE.com or through customer premise devices such as In Home Displays (IHDs) and Energy Management Systems. The HAN capability of the SmartConnect meters, essential for allowing data from the smart meter to be shared with customer devices, had also not yet been enabled.

Customers with a RTEM meter (demand greater than 200 kW) were billed on an interval basis, and did have access to interval usage data online through a program called SCE Energy Manager. This web-based program provides comprehensive energy usage information and analytical tools to help customers manage their energy usage effectively.

101 SCE, Response and Opening Comments to the AFV OIR, p. 17 (August 20, 2009). http://docs.cpuc.ca.gov/efile/CM/107997.pdf.

2. Roadmap

The sections below describe SCE's plans to deploy the infrastructure elements required for the capabilities in this domain.

a) Customer Empowerment Platform Infrastructure Deployment

Much of the infrastructure required to deliver the capabilities in this Domain is described in the Platform Infrastructure Baseline & Roadmap (Section V.E) above. This includes Smart Meters, the AMI network and back office systems, customer information systems (such as customer data warehouse, CRM, and CSS), SCE.com, Field-Area Network, GIS, and Cyber Security.

b) Customer Premise Devices

Customer premise devices are a key enabling technology for empowering customers to better manage their energy usage and participate in SCE's DR programs as well as TOU and dynamic pricing tariffs. In the near-term, SCE's roadmap focuses on piloting devices that leverage SCE's SmartConnect deployment and enablement of the HAN to provide enhanced DR capabilities to customers below 200 kW. The HAN will serve as a common platform that allows devices—such as IHDs, Programmable Communicating Thermostats PCTs, and Energy Management Systems—to communicate with smart meters so that customers can receive real-time usage data, price information, and DR event signals. Looking forward, SCE expects to see tremendous growth in this emerging market and plans to provide support for customers who procure standardized HAN devices through retail distribution channels. SCE's roadmap for customer premise devices includes deployment of infrastructure needed to transition the existing Summer Discount Plan to a price responsive program that supports PCTs and integrates with CAISO's wholesale market.

SCE has initiated several small-scale pilot projects to analyze the integration and utilization of customer premise devices for enabling DR and Enhanced Customer Engagement capabilities. SCE launched a small scale IHD field trial in the fourth quarter of 2010 that engages 36 customers and serves as a proof of concept for pairing energy information displays and energy management systems to the meter. This field trial has a near-term focus on assessing the current capabilities of these devices – primarily the provision of near-real-time usage data – and will provide enhanced understanding of operational needs moving forward. Beginning in the fourth quarter of 2011, SCE will conduct a Home Battery Pilot Project which will deploy residential energy storage units (RESUs) in up to 18 different customer locations to assess their performance in a variety of environments and applications. RESUs may eventually play an important role in facilitating permanent load shifting and further integrating vehicle charging in grid operations. Finally, the Energy Smart Customer Devices portion of the Irvine Smart Grid Demonstration (ISGD) project will

holistically evaluate many interoperating devices and technologies in an integrated energy environment. This pilot entails approximately 40 residential customers and will test IHDs, PCTs, energy management systems, smart appliances, plug load monitors, home batteries, as well as solar PV installations.

As SCE's SmartConnect deployment nears completion, SCE will conduct two limited launches to instruct full program implementation for HAN devices—primarily IHDs and PCTs. By the first quarter of 2012, SCE plans to launch an Interim HAN Solution that will act as a bridge to full-scale HAN functionality and allow SCE to begin developing a scalable, flexible framework of systems and processes needed for device registration and basic troubleshooting. The Interim HAN Solution will provide 500-2,000 residential customers with IHDs and USB Dongles through which SCE will provide real-time usage data from the meter. The devices will also receive event notifications sent via the ALCS and back office systems.

The Interim HAN Solution lays the groundwork for full IHD roll out in 2013 as part of SCE's Save Power Day Incentive Program (formerly known as PeakTime Rebate). In the Save Power Day Incentive Program, customers who acquire and install qualified enabling technologies (such as utility-registered communicating graphical information-feedback displays) will be credited $1.25 for each kWh they reduce their usage below their established baseline during an event. In 2013, when the ALCS system is expected to support SEP 2.0 load control capabilities, SCE will perform a limited launch of PCTs to roughly 500 residential customers. This limited launch will allow SCE to perform end-to-end testing of the technology and supporting systems while also allowing for evaluation of business processes to identify any issues before full PCT roll-out as part of the Summer Discount Plan.

As part of SCE's plan to transition the residential SDP to a price responsive program in 2011 and 2012, SCE is proposing to provide legacy customers with new program options that would allow customers to override 5 events per calendar year. As part of its SDP transition Application filed in June 2010, SCE proposes to install new radio-enabled, override-able load switches for customers electing the override-able program option. This override capability is critical for preserving customer choice and, ultimately, customer retention in the program as price-responsive SDP will be dispatched much more frequently than the traditional SDP. After completion of the limited launch of PCTs in 2014, SCE plans to offer both PCTs and override-enabled load switches as technology options in this same SDP program design.[102]

102 In order to enable the PCT offering, SCE must implement the HAN capabilities. SCE's ability to offer these capabilities is dependent upon a number of factors including the ratification of the Smart Energy 2.0 profile, commercial product availability, advanced load control system development and implementation, and overall integration with SCE's back office systems.

c) Advanced Load Control System

The ALCS is one of the key systems that will enable SCE to offer HAN capabilities to its customers. ALCS will also play a crucial role in enabling SCE to offer the next generation of DR programs to customers and to realize the DR and energy conservation benefits associated with implementing the SmartConnect program. ALCS functionality includes DR program management, HAN device registration and management, load reduction forecasting, load control event dispatch, HAN communications (text messages, price signals, billing data), and system administration. The ALCS will communicate through the SCE NMS to the HAN devices via the SEP 2.0 wireless communication standard.

The first release of ALCS, planned for 2012, will enable basic HAN device registration and text messaging functionality so that SCE can register energy information displays to the SmartConnect meter to offer customers access to near real-time demand and usage data. The second ALCS release, planned for 2013, will support offering a PCT program to customers. Releases 1 and 2 will be funded through the SmartConnect program. Additionally, SCE anticipates enhancements to this basic functionality, including a second path from the ALCS to the HAN device through a customer's internet connection and addressing potential integration issues between the ALCS and SCE back office systems. These enhancements, funded through SCE's 2012-14 Demand Response Application,[103] are expected to cost approximately $1.5 million from 2012 to 2014.

SCE anticipates a third ALCS release that will support future concepts such as integration with the DMS for event dispatch, DER and PEVs. Timing and costs for Release 3 have not been determined, but is expected to take place after 2014.

In addition to the ALCS, SCE plans to continue making system enhancements to its existing load control and event dispatch systems. These enhancements, not including ongoing vendor licenses and system operations, will be funded through SCE's 2012-2014 DR Application[104] at an expected cost of $2.7 million.

d) Energy Service Provider Interface

SCE anticipates that it will provide usage data to authorized third parties leveraging the ESPI standard that is expected to be ratified by the North American Energy Standards Board (NAESB) in late third quarter 2011. SCE is actively involved in the development of ESPI as part of the NAESB standards development process. As a result of the May 2011 Proposed Decision Adopting Rules to Protect the Privacy and Security of the Electricity Usage Data of the Customers of Pacific Gas & Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, SCE expects that it will be required to develop

103 SCE, 2012-2014 Demand Response Application, SCE-1, Vol-2, p. 137.
104 *Ibid.*

a specific plan and cost estimate around the implementation of ESPI and third party access to customer usage data.

e) PEV-Specific Metering

With regard to discrete measurement of PEV load in the 2011-2014 time period, SCE will support continued customer choice in selection of the aforementioned PEV rates and their associated single or separate metering configurations as instructed in the AFV OIR.[105] SCE plans to deploy approximately 24,000 additional AMI meters at a total cost of $11 million to accommodate customer adoption of time-variant PEV rates through 2014.[106] All meters installed to this end will leverage the AMI network and back-office systems deployed as part of SmartConnect to acquire and manage PEV load data.[107] Also in the 2011-2014 time period, SCE will test and demonstrate communication of PEVs and/or EVSE with SCE's smart meters to enable discrete, single-meter measurement of PEV load as well as other DR capabilities. SCE's Smart Charging PEV Pilot[108] will investigate utilization of the utility's AMI to effectively manage plug-in vehicle loads. Through this pilot, SCE will explore DSM programs that aim to reduce overall system demand along with programs that decrease the impact of vehicle charging on distribution infrastructure such as transformers.

f) PEV Metrology & Communication

The recent Phase 2 Proposed Decision in the AFV OIR included language that would require SCE and stakeholders to develop a standard protocol for submetering solutions that may exist in various physical locations.[109] While directives on this subject will not be final until issuance of the Final Decision, SCE is currently conducting research to explore various submetering possibilities including communication and integration with EVSE-embedded sub-meters or on-board vehicle metering technologies. Submetering may also include installation of an additional, in-series SmartConnect meter as a low cost alternative to existing, separate metering arrangements which require costly circuit panel upgrades. Emerging technologies for PEV metering and load management may leverage various communication pathways

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105 "[U]tilities should continue to make available all existing meter arrangement options to customers, which currently include single meters or separate meters. Our finding emphasizes the importance of preserving customer choice in PEV meter arrangements at this early PEV market development stage as a means of encouraging technological advancements." See Phase 2 Decision Establishing Policies to Overcome Barriers to Electric Vehicle Deployment and Complying with Public Utilities Code Section 740.2, p. 30.

106 SCE's 2012 GRC Phase 1 Application (A.10-11-015), SCE-04, Vol 4, pp. 13.

107 A Phase 2 Decision in the AFV OIR recently confirmed the "utilities' obligation to ensure that PEV meters are AMI and HAN enabled." See Phase 2 Decision Establishing Policies to Overcome Barriers to Electric Vehicle Deployment and Complying with Public Utilities Code Section 740.2, p. 30.

108 SCE, 2012-2014 Demand Response Application, SCE-1, Vol-2, p. 102.

109 *See* Phase 2 Decision Establishing Policies to Overcome Barriers to Electric Vehicle Deployment and Complying with Public Utilities Code Section 740.2, p. 26.

including SmartConnect and HAN networks currently supported by SCE, PLC, and broadband over wireless. Looking beyond 2015, SCE anticipates potential deployment of PEV submetering and supporting communication infrastructure in the event that utilities are allowed to own and operate such equipment as determined by the AFV OIR.

While technological advancements and regulatory drivers will dictate the nature and extent of SCE's deployment of PEV Metrology & Communications, SCE will begin real-world testing and demonstration of desired PEV Integration capabilities through two pilots proposed in the 2012-2014 DR Application:

- SCE's Smart Charging PEV pilot will test the utility's AMI and HAN network as a means to communicate with and manage PEV loads as a first step in evaluating the costs and benefits of a PEV charging program. SCE will conduct lab testing to evaluate the functionality of smart EVSE as well as smart PEVs in a controlled environment. These tests will be performed primarily to investigate communication compatibility between smart meters and/or utility wide-area networks (WANs). In addition, once communication is established, a series of separate tests can verify the smart charging equipment's ability to receive DSM signals and respond accordingly. SCE will also deploy "smart charging" equipment, load control system equipment, and back office simulation in several controlled locations to test utility DSM signals and capture possible challenges with deploying equipment in real-world conditions. Communication systems such as ZigBee Protocol will be evaluated for residential applications and OpenADR for Commercial applications. The information obtained from this pilot will help SCE identify the hardware and communication technologies that are best suited for implementation in future load management programs. The forecasted cost of this pilot project is $0.6 million in 2012-2014.

- SCE's Workplace Charging Pilot[110] will deploy EVSE at SCE facilities to test, monitor, and analyze the impacts of PEV workplace charging. This pilot will test impacts to building or facility electric supply systems and help to determine user preferences in pricing options and DR capabilities. To learn more about hardware performance, electrical system impacts, and back-office integration, SCE intends to deploy up to 233 PEV charging stations at SCE facility parking lots. User load will be measured at each charging station and electricity will be paid for by the individual consumer using the charging stations. Utility metering will measure ongoing load profiles for aggregate charging on each circuit and will allow SCE to assess the effectiveness of various DR pilot program strategies. SCE will test communication from individual charge stations to back office systems for billing and settlement. Finally, load management, price signaling and DR load reductions will be controlled by OpenADR messaging via gateway devices at each SCE site under the control of SCE DR management systems. The forecasted cost of this pilot project is $1.2 million in 2012-2014.

110 SCE, 2012-2014 Demand Response Application, SCE-1, Vol-2, p. 108.

Findings from the aforementioned PEV charging pilots will instruct future DR program offerings and provide insight into the type of communication technology and system enhancement that will be required to support further PEV Integration.

g) Customer Information Systems

In addition to the general deployment of these systems as described in Section V.E.3, SCE has plans to make specific system modifications through a variety of projects to enable specific Customer Empowerment capabilities.

Various Customer Information Systems will be upgraded as part of the Dynamic Pricing project.[111] The purpose of this project is to perform system modifications required to support the additional dynamic pricing rates and associated rate analysis and energy management tools. These new rates are required by D. 09-08-028 and will be effective in late 2012 or early 2013.[112] Systems impacted by these changes include CSS, Customer Data Warehouse, SCE.com, and several energy management tools. Forecasted costs for this project are $33.0 million in 2011-2012. There will be additional dynamic rates implemented in subsequent years, but the scope, timing, and cost of system upgrades that will support these rates are unknown.

SCE plans to create new Customer Information System functionality through the Alerts and Notifications project.[113] This new system will automate the delivery of important information to help customers manage their bill and payments, prepare for planned outages, and successfully adopt a smart energy lifestyle by taking advantage of dynamic pricing, DR, and EE programs. The system is planned for deployment beginning in late 2012 and ending in the third quarter of 2014, at a forecasted cost of $19.9 million. No future work beyond 2014 is anticipated as a stand-alone project.

Under the Plug-In Electric Vehicle Support Systems project[114], SCE plans to upgrade customer information systems in the 2012-2014 time period to support a more efficient and transparent process by which customers can enroll in dynamic rates for PEVs. The PEV Support Systems Projects will be completed by 2014 at a total cost of $8.4 million.

Also, depending on utility requirements to support a PEV submetering protocol, SCE will likely upgrade customer service systems to support subtractive billing and device integration in this time period. Looking beyond 2015, SCE expects ongoing investment in upgrading PEV support systems to accommodate new technologies and capabilities as the PEV market continues to develop.

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111 SCE, 2012 GRC Phase 1 Application (A.10-11-015), SCE-04 Vol. 04, pp. 75-87.
112 The specific implementation date will be determined in SCE's 2012 GRC Phase 2 Application proceeding.
113 SCE, 2012 GRC Phase 1 Application (A.10-11-015),SCE-04, Vol. 04, p. 20.
114 *Ibid.*, p. 61.

As part of the HAN Support and Troubleshooting[115] project, SCE will design and implement enhancements and upgrades to the basic HAN functionality that will be delivered as part of SmartConnect, as well as design and implement new system functionality that was not envisioned at the time of the SmartConnect business case. These incremental system capabilities will be critical to enable business processes and customer service operations needed to support the widespread availability of HAN devices through retail distribution channels and utility programs. These capabilities include assistance with ongoing device utilization, understanding the customer's energy usage information and providing information and recommendations for improvement, and a more streamlined process for helping the customer troubleshoot their network to locate problems that may arise. The cost to develop these capabilities (a one-time effort) is estimated at $8.3 million in 2012.

As discussed in the DR Application,[116] SCE plans to make several other enhancements to customer information systems during the 2012-2014 time period. These include modifying the SCE Energy Manager Application to allow any business customer with at least one account with demand that exceeds 200 kW to utilize all of the SCE Energy Manager features for all of its other accounts with demands below 200 kW that are enabled with SmartConnect meters, as well as modifying the DR Module to allow all business customers with SmartConnect meters to participate in DR events. It also includes modifications to the Energy Analytics Platform and CSS settlement systems as part of an effort to implement geographic dispatch for programs participating in PDR and RDRP, modifications to CSS due to changes in DR dual participation rules and settlement baseline methodology changes, development of web pages to communicate the event status for all of the price-responsive DR programs and integrate this set of web pages with the DRAS, and development of a web based DR decision wizard that would enable customers to determine which DR programs are best suited for their specific needs. These efforts are expected to cost $2.8 million from 2012-2014.

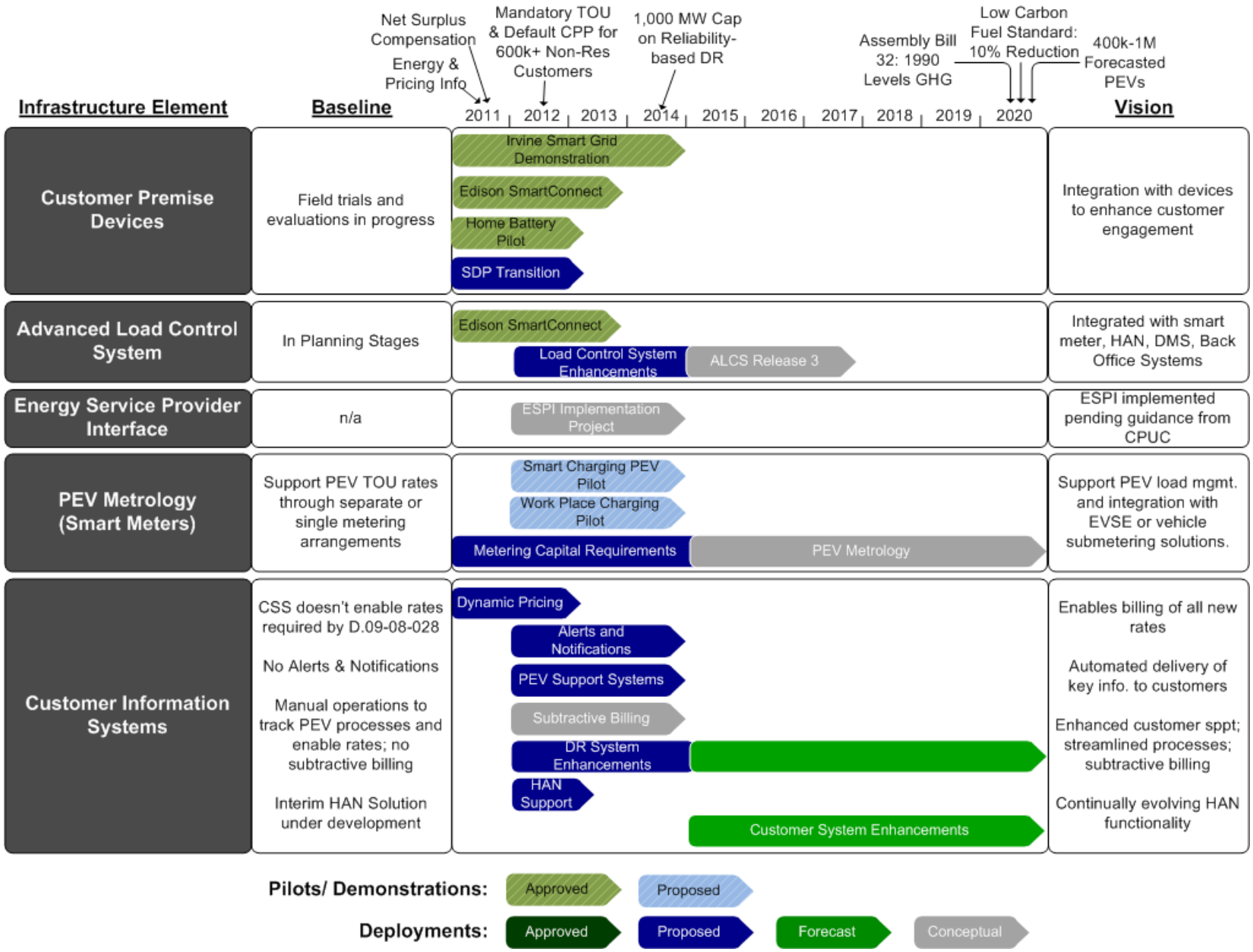
For the 2015-2020 time period, the scope, timing, and cost of projects related to systems in support of Enhanced Customer Engagement are unknown. However, based on SCE's currently considered projects during that time and the expected timing of version upgrades and maintenance, SCE estimates conceptual costs between $50 million and $125 million per year for customer system enhancements in the 2015-2020 timeframe.

h) Summary

Figure 24 on the following page summarizes the baseline status of the infrastructure elements described above, planned deployments of this infrastructure between 2011 and 2020, and the future state vision for each of these infrastructure elements.

115 SCE, 2012 GRC Phase 1 Application (A.10-11-015),SCE-04, Vol. 04, p. 54.
116 SCE, 2012-2014 Demand Response Application, SCE-1, Vol-2, pp. 140-143.

Figure 24 – Customer Empowerment Baseline and Roadmap Summary



G. Distribution and Substation Automation Baseline and Roadmap

As discussed above, the smart grid capabilities in the Distribution and Substation Automation domain – DER Integration, Outage Management and Advanced Volt/VAR Control – will address the complexities associated with integrating DER, as well as take advantage of opportunities to save energy and improve its outage response abilities. The sections below present a baseline of these capabilities, followed by a roadmap that describes SCE's plans to deploy infrastructure that will enhance its ability to deliver these capabilities in the future.

1. Baseline

The sections below describe the baseline state of each capability in the Distribution and Substation Automation domain.

a) DER Integration

While there are over 50,000 DG facilities interconnected to California's electricity system, these facilities represent less than 800 MW of generation capacity – little more than 1 percent of total in-state generation capacity.[117] Given this relatively low level of DER penetration, existing practices and technologies are adequate for distribution protection and Volt/VAR control. Accordingly, apart from infrastructure that SCE is deploying as a platform investment, the company has not undertaken any deployments specifically serving its DER Integration capabilities.

In the years covered by the Deployment Plan, SCE expects that DER penetration will have significant circuit-level impacts. In particular, DG installations that appear in "clusters" as a result of optimal conditions for energy production, such as large amounts of rooftop space for PV installations, may cause localized problems that SCE will have to address in the near-term. SCE is currently assessing resource needs and mitigation measures for "at risk" circuits while performing technology evaluations and real-world pilot projects to prepare for future deployments.

b) Advanced Outage Management

SCE's current fault protection systems enable advanced outage management to a certain degree. The company installs remote control switches (RCS) on distribution circuits that enable it, in certain cases, to isolate half of a circuit where a fault has occurred. This system, however, has shortcomings. Using the RCS-based scheme, all customers lose service for a least a few minutes because the circuit breaker at

117 Itron, Impacts of DG, Final Report (Jan 2010) (prepared for CPUC and CEC Staff).

the substation opens and de-energizes the entire line upon detection of the fault. The circuit breaker then works in concert with a switch located approximately half-way down the line to isolate the one half of the circuit where the fault is located, and restore power to the customers on the other half of the line. This level of automation is consistent with conventional utility service and has led to meaningful reductions in Customer Minutes of Interruption (CMI) when compared with purely manual operations. However, the process takes several minutes (or longer during storm conditions) and, immediately following the fault, all customers on an affected circuit will lose power.

As of December 31, 2010, SCE had installed 3,812 RCSs on 2,079 different distribution circuits out of a total of 4,459 circuits (46 percent). SCE had also installed 150 Remote Fault Indicators (RFIs) and 1,000 Remote Automatic Reclosers (RARs). No circuits had been equipped with URCI-based automation. All of these existing automation devices were equipped with NETCOMM radios, allowing for communication with the Distribution Management System.

c) Advanced Volt/VAR Control

To implement its Advanced Volt/VAR capability, SCE needs four elements. First, it needs the ability to remotely control the capacitor banks deployed across its distribution system. As of December 31, 2010, SCE had installed 13,100 capacitor banks on its distribution system – 10,080 of which were equipped with the programmable capacitor controls needed to perform AV/VC. In addition, SCE needs its FAN and substation LAN at the substation serving circuits on which AV/VC will be implemented to communicate with its capacitor controls. Sections V.E.5 and V.E.6 describe the progress of SCE's FAN and substation LAN deployments, respectively. Finally, SCE needs to activate the AV/VC software that will be installed as part of its DMS upgrade. SCE's existing DMS does not support the advanced applications or the enhanced remote control and monitoring of capacitor banks required to implement AV/VC.

2. Roadmap

The sections below describe SCE's plans to deploy the infrastructure elements required for the capabilities in this domain.

a) Distribution and Substation Automation-Related Platform Infrastructure Deployments

Distribution and Substation Automation capabilities will leverage several platform infrastructure elements, including the AMI infrastructure, field area network, substation LAN, DMS, OMS, GIS, and cyber security. Information about deployments of this infrastructure is available in Section V.E.

b) Distribution Switching Equipment

The next generation of automated switching devices (known as URCIs) may allow for circuits that are truly self-healing. These devices, combined with the high speed wireless protection communications described below will enable detection and isolation of faults before the substation circuit breaker is opened, as happens with the existing RCS-based protection scheme.

SCE is working with equipment suppliers to develop URCI technology. As part of the Integrated Smart Distribution pilot project,[118] SCE plans to install the URCI-based automation system on 12 circuits per year from 2012 through 2014. This will include several components including the URCI itself, RFIs, Advanced Distribution Capacitor sets, a Duct Bank Temperature Monitoring System, an Incipient Fault Detection System, and a Fault Location System. Total cost per circuit is forecast to be approximately $828,000 for new circuits and $878,000 for existing circuits (in 2009 $s), for a total cost of $33.4 million from 2012-2014. SCE will also demonstrate a circuit with similar equipment as part of the ISGD project.

While evaluating the new technology, SCE plans to continue deploying RCS-based automation through its existing Circuit Automation Program[119] on 134 circuits per year from 2011-2014. Throughout this period SCE plans to install 718 RCSs, 31 RFIs, and 60 RARs. Total cost for this program is estimated to be $25.9 million from 2011 to 2014.

In 2015 and beyond, two factors will dictate whether and how quickly URCI-based automation becomes standard at SCE: (1) its effectiveness in reducing CMI relative to existing RCS-based automation, and (2) its cost relative to RCS-based automation. The first factor is difficult to predict at this time. Throughout the Integrated Smart Distribution pilot project, SCE will evaluate the effectiveness of URCI-based automation so that by the end of the project enough data should exist to allow for fairly accurate projections of CMI reduction. The second factor is also difficult to predict at this time. The cost of URCIs is likely to drop over time, perhaps as much as 50 percent. It is likely to remain more expensive than RCS-based automation, but the hope is that the increased effectiveness in CMI reduction would more than make up for the cost differential.

In addition, SCE expects to increase the number of RFIs deployed, as the unit cost of this technology decreases over time. SCE also expects to continue deploying RARs during the period of 2015-2020.

118 SCE, 2012 GRC Phase 1 Application (A.10-11-015), SCE-03 Vol.2, p. 50.
119 *Ibid.*, p. 36.

c) Distribution Volt/VAR Devices

As part of the Capacitor Automation program, SCE will complete almost full deployment of programmable capacitor controls (PCC) by the end of 2014.[120] Switched capacitor banks are a key technology used to regulate voltage and VAR on the distribution system. Without capacitor banks, the voltage supplied to SCE customers would drop to levels that can damage the customers' equipment or appliances and present safety hazards. Automation of these capacitor banks through installation of a PCC allows SCE to remotely monitor and control the operation of these devices, rather than sending a person to operate the device manually in the field. As discussed in the AV/VC baseline section, when integrated with SCE's FAN and DMS, PCC-equipped capacitor banks also enable SCE's Advanced Volt/VAR capability.

SCE currently has three types of capacitor controls deployed on its distribution system: purely mechanical controls, first-generation automated controls, and the modern radio-enabled PCCs being installed today. Purely mechanical controls and first-generation automated controls are considered obsolete – replacement parts are no longer available and vendors no longer provide support for these devices. During the 2012-2014 time frame, SCE intends to have an installation rate of about 454 total PCCs per year at an average cost of $2,817 per unit installed. As a first priority, SCE plans to upgrade remaining mechanical controls to modern PCCs by the end of 2012. Because of their age and lack of vendor support, first-generation PCCs are expected to fail at an increasing rate. SCE will commence replacement of this population of devices in 2011 and expects to finish replacement by 2016.

Total cost of PCC deployments during 2011-2014 is forecast at $4.8 million. From 2015-2020, SCE expects to continue replacing obsolete capacitor controls, replace failed control, and install controls on new capacitor banks. Total cost of these deployments is estimated to be between $5 and $14 million in total during this period.

While SCE currently uses these PCC-equipped capacitors to manage voltage on distribution circuits, these devices are not flexible enough to correct the voltage issues that will occur as more intermittent renewable resources are connected to the distribution system. To better address distribution system voltage issues and to facilitate the integration of intermittent distributed energy resources, SCE will evaluate Distribution Static VAR Compensators (DSVC) in the 2012-2014 timeframe as part of the Integrated Smart Distribution pilot project.[121] DSVCs are fast acting reactive power adjustment and supply devices that provide rapid (within fractions of a second) voltage support on distribution circuits. DSVCs are more dynamic, faster-acting devices that can help to balance rapid, unpredictable voltage fluctuations and enhance power quality across a given distribution circuit. SCE plans to install up to two DSVCs at substations that serve circuits with high levels of solar PV in each year from 2012 through 2014 at a cost of $350,000 per DSVC, for a total cost of $2.3 million.[122]

120 *Ibid.*, p. 45.
121 SCE, 2012 GRC Phase 1 Application (A.10-11-015), SCE-03, Vol.2, p. 60
122 *Ibid.*, p. 59

The Integrated Smart Distribution Project will test whether these devices can adequately and cost-effectively address issues caused by increased renewable generation on the distribution system. Pending the results of this pilot and findings from related demonstration projects, SCE will continue to track DG adoption rates and assess voltage management issues to determine the need for continued deployment of DSVCs beyond 2015.

d) Advanced Relays

An advanced relaying system with two-way fault detection capabilities will be piloted as part of SCE's ARRA-funded ISGD Project as well as the Integrated Smart Distribution project proposed in SCE's 2012-2014 GRC.[123] In the Integrated Smart Distribution pilot project, SCE will install 30-50 advanced relays per year in the 2012 through 2014 time period at a total cost of $4.7 million ($31,000 per relay).[124] SCE will leverage findings and best practices from these projects to instruct full-scale implementation beyond 2015. At this time SCE expects advanced relays will be incorporated into the Substation Automation-3 implementations as discussed in Section V.E.6. In addition, the increasing use of URCI to perform automated switching in response to outages (see the Outage Management capability discussion) may mitigate the need for advanced relays on distribution circuits.

e) High Speed Wireless Protection Communication Network

The High Speed Wireless Protection Communication Network is a critical component of the envisioned Self-Healing Circuit. This type of network has very low latency, allowing for near-instantaneous communication when faults are detected. The network requires installation of wireless radios on the devices located on a feeder as well as an antenna at the substation that serves the feeder. SCE has demonstrated the fast switching that this network would support over a fiber optic network in its Avanti "Circuit of the Future" project in San Bernardino. SCE plans to test this technology further as part of the ISGD Project, and SCE is now working with GE to prove the capability over a wireless communications network. It will also be evaluated in conjunction with URCIs in the Integrated Smart Distribution pilot project.[125] Depending on the results of these evaluations, High Speed Wireless Protection Communication equipment could be ready for full-scale deployment as early as 2015. However, as this technology would be used in conjunction with URCIs, the scale of deployment will depend on the factors discussed above regarding future deployments of URCIs.

123 *Ibid.*, p. 60.
124 *Ibid.*
125 *Ibid.*, p. 50.

f) Energy Storage

SCE intends to deploy a combination of energy storage system technologies for a number of purposes, all directed at improving the company's utilization of renewable resources, reducing system loading and losses, and increasing reliability of service to its customers. As an increased amount of intermittent resources are added to SCE's energy supply mix to meet legislative and regulatory policy goals, energy storage is expected to become a viable option to facilitate and enhance distribution grid operations. In the 2011-2014 time period, SCE will conduct a number of demonstration projects and limited deployments that evaluate the utilization of energy storage devices for DER Integration:

- As part of the Integrated Smart Distribution pilot project[126], SCE will conduct limited deployment of energy storage units with advanced inverter systems to address circuit overloading and voltage fluctuation at the distribution level. Energy storage devices deployed under this initiative will store energy created by intermittent generation resources for more efficient and effective utilization by customers. Similar to DSVCs, storage units coupled with advanced inverters can provide fast-acting energy modulation to balance out local voltage fluctuations caused by distributed photovoltaics and other intermittent generation technologies.[127] SCE plans to conduct a preliminary deployment of one transportable energy storage system in each of the years 2012, 2013, and 2014 to prepare for an expected, increased utilization of these devices in 2015 and beyond. The cost of these systems is expected to be $10.6 million from 2012-2014.

- A Community Energy Storage (CES) system will be deployed as part of the ISGD project. CES are distributed energy storage units connected to the secondary transformers serving a few houses or small commercial loads. SCE will test and evaluate the ability of CES to provide voltage fluctuation mitigation, improve service reliability and circuit efficiency, and minimize the impact of PEV and customer DER. The ISGD project will also demonstrate a large transportable energy storage system (2MW/0.5MWh) to explore control and protection strategies with significant reverse power flow capability. Two distribution circuits which can be operated either radially or as a single loop will be used to evaluate various strategies of circuit constraint management.

SCE has not formalized plans for demonstration or deployment of distribution-sited energy storage beyond 2014. While continuing testing and evaluation of different storage technologies in the lab, SCE will leverage the findings from the aforementioned pilot projects to assess the viability of storage used for integration of intermittent renewables on the distribution system. The information obtained from these

126 *Ibid*., p. 60.

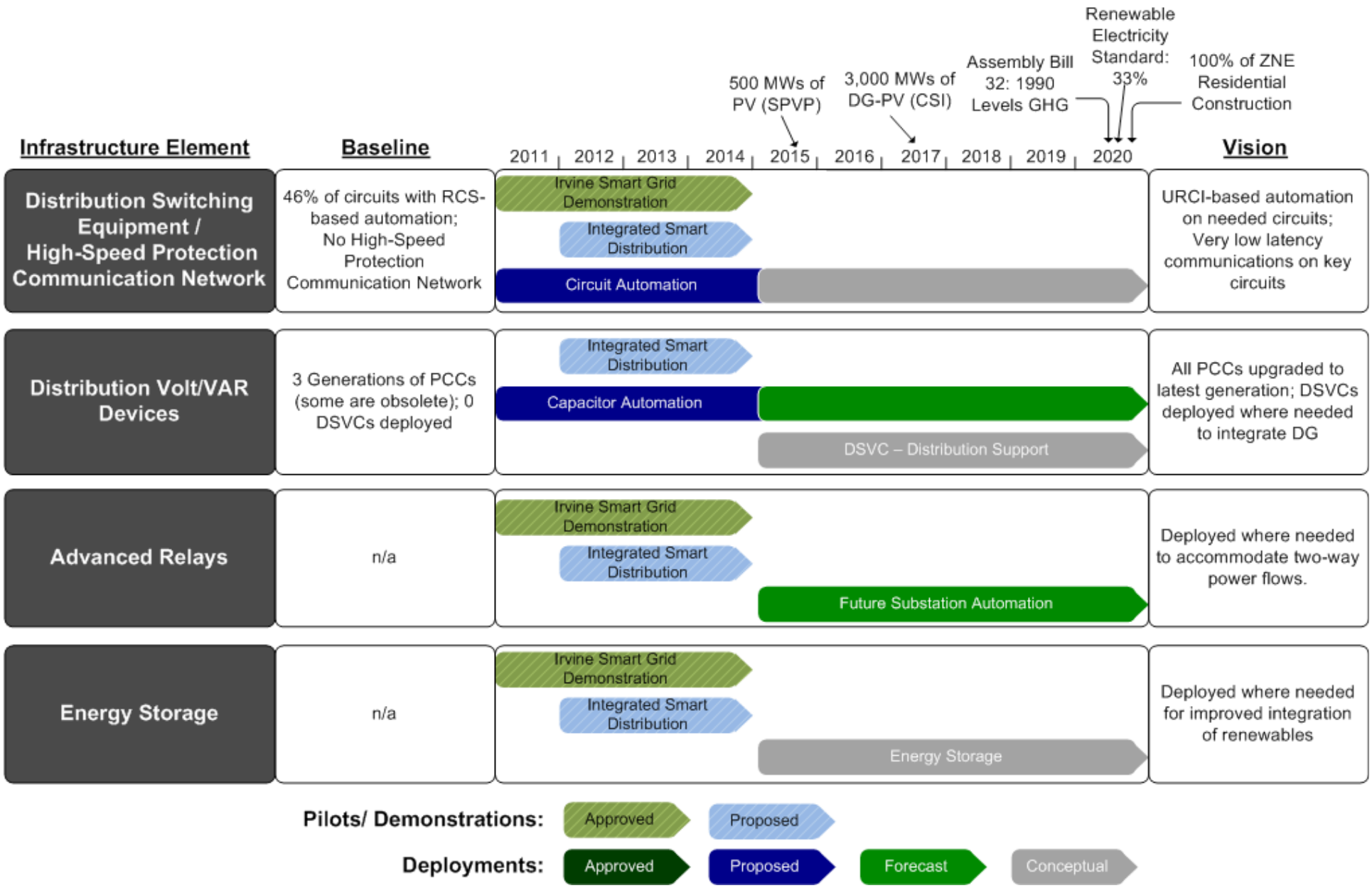
127 Inverters are typically coupled with distributed generators or storage systems to convert DC electric current into the AC electric current that is required for use on the grid. Inverters are therefore a necessary component of many energy storage systems but, with improved automation and intelligence, they can be coordinated or programmed to balance rapid fluctuations in a manner similar to DSVCs.

pilots will instruct future deployments by helping SCE to collect data on cost, performance, and grid impacts while also gaining experience in the installation, operation, and maintenance of said devices.

g) Summary

Figure 25 on the following page summarizes the baseline status of the infrastructure elements described above, planned deployments of this infrastructure between 2011 and 2020, and the future state vision for each of these infrastructure elements.

Figure 25 – Distribution and Substation Automation Baseline and Roadmap Summary



H. Transmission Automation Baseline and Roadmap

1. Baseline

As of December 31, 2010, SCE had limited wide-area monitoring, control and protection capabilities. The company currently has PMUs installed at 20 of the approximately 75 transmission and generation substations where it ultimately plans to install PMUs. Data from these PMUs are currently analyzed with development-stage visualization tools, although neither these data nor these visual tools are used in day-to-day transmission system operations.

With respect to wide-area protection, SCE had 17 separate remedial action schemes (RAS) deployed and protecting its transmission system as of December 31, 2010. SCE uses a logic controller to exercise very limited coordination of these RAS. In reality, each of the RAS act independently of other RAS and can be thought of as remote "islands" of transmission protection and remediation actions. The number of required new RAS is driven in large part by renewable interconnections, limitations in existing RAS technology and the increasing issues related to overlapping RAS make coordinating existing and future RAS nearly impossible using the existing RAS technology and approach.

Finally, SCE had not developed Wide-Area Control capabilities as of December 31, 2010. Although SCE has installed some FACTS devices in two substations to manage voltage issues in a particular transmission corridor, they have not been incorporated into any wide-area control strategy.

Transmission Automation also relies on several platform infrastructure elements including the high speed backbone, substation LAN, energy management system and GIS. The baseline state of this equipment is described in Section V.E above.

2. Roadmap

In the next ten years, SCE anticipates deploying much of the infrastructure required for the WAMPAC capabilities. The sections below describe these plans and SCE's level of certainty about each deployment.

a) Transmission Automation-Related Platform Infrastructure Deployments

Transmission Automation will leverage several platform infrastructure elements, including the high speed backbone, substation LAN, EMS, GIS, and cyber security. Information about deployments of this infrastructure is available in Section V.E.

b) Phasor Measurement Units

As part of SCE's Phasor Measurement & Wide-Area Situational Awareness Project,[128] SCE plans to begin deployment of PMUs at bulk power substations during the 2011-2014 time period. PMUs are expected to be installed in four bulk power substations in 2011, seven in 2012, six in 2013, and six in 2014, for a total of 23 substations. Per-substation costs were expected to be $660,000 in 2009 dollars, resulting in a total cost of $17 million for PMUs from 2011-2014.

This project is expected to continue through at least 2020. PMUs will be deployed until all 48 bulk stations and approximately 26 generation interconnections are equipped. Given uncertainties around the timing and cost of these deployments, costs are estimated to be within the range of $23 to $61 million from 2015 to 2020.

c) Wide-Area Situational Awareness System

WASAS is being deployed as part of SCE's Phasor Measurement & Wide-Area Situational Awareness Project, under which SCE will invest in (1) hardware and data storage systems to manage PMU data, (2) operator and analyst user interfaces, and (3) advanced phasor data analytics capabilities for reports and engineering analyses. WASAS development is expected to cost approximately about $39 million in capital during 2011-2014. In addition, O&M related to this project is expected to be $3.8 million.[129]

WASAS will continue to evolve beyond 2014, with potential enhancements including additional analytic capabilities and applications, increased data storage capabilities, upgraded infrastructure to support data growth, improved data visualization for grid operators, and interfaces to WECC member utilities and CAISO. Costs are estimated to be within the range of $15 to $40 million from 2015 to 2020.

d) Centralized Remedial Actions Scheme

SCE has created the C-RAS[130] project to deploy infrastructure required to coordinate current and future RASs. The central element of this deployment is the C-RAS Central Controller Facility (CCF), which effectively replaces the logic controllers that exist today. The CCF will support fully informed, efficient and automated decisions to initiate remedial protective actions across multiple RAS in the event of a transmission system event.

Through the C-RAS project, SCE will also substantially upgrade the telecommunications equipment and protocols that SCE currently uses for RAS. The point-to-point fiber optic connections will be replaced by

128 SCE, 2012 GRC Phase 1 Application (A.10-11-015), SCE-03 Vol.2, p. 81.
129 *Ibid*,, Vol.5, p. 47.
130 *Ibid*,, Vol.2, p. 88.

an ethernet LAN providing shared communication connections between relays and other devices. Each substation local area network will connect to the CCF using the redundant, secure and dedicated high capacity communication network that already connects most of the substations within the SCE grid.

During Phase I of the C-RAS project one existing RAS will be upgraded to C-RAS in a production mode. In addition, eight new RAS will be incorporated into C-RAS during the period 2011-2014. The total investment in C-RAS during this period is expected to reach approximately $123 million in capital and $3.5 million in related O&M costs.[131]

Between 2015 and 2020, C-RAS is expected to expand coverage to approximately 100 substations associated with converting the remaining 15 existing RAS by the end of the decade. In addition, new RAS will continue to be incorporated into C-RAS. Total investment is preliminary at this point, but is expected to be within the range of $13 to $35 million.

e) Advanced Relays

Advanced relays have the potential to be an important part of wide-area protection. C-RAS may eventually use intelligent relays that perform multiple functions of "send," "receive" and "self-check" and ensure a level of redundant functionality that meets or exceeds NERC/WECC requirements. However, these advanced relays may not be incorporated into C-RAS until after 2020.

Advanced Relays may also be used on transmission corridors. SCE is currently researching the use of advanced relays on the transmission system as part of the DOE funded Application of Advanced Wide-Area Early Warning Systems with Adaptive Protection project. The purpose of the project is to determine how synchrophasor data can be used to improve the reliability of electricity delivery (including minimizing false trips by protective relays). One advanced relay will be installed on Edison's Midway-Vincent No. 1 500-kV line, which will serve as the demonstration site for this application. Depending on the results of this demonstration project, advanced relays may be installed on additional transmission corridors during the period of 2015-2020. Until these results can be evaluated, the timing, volume, and unit costs of future deployments will remain unknown.

f) Wide-Area Control System

SCE does not plan to begin development of a Wide-Area Control System during the 2011-2014 time period. The timeframe for initiating this type of system would be 2016 at the earliest and would be conditional on successful implementation of the WASAS and C-RAS. A Wide Area Control System is likely to be a very expensive management and control system and would require extensive research, development,

131 *Ibid*,, Vol. 5, p. 45.

and demonstration before it would be deployed in a production environment. Until the requirements and scope of this system are determined, SCE will be unable to provide cost estimates.

g) Flexible Alternating Current Transmission System (FACTS) Devices

FACTS devices such as static VAR compensators (SVCs), static synchronous compensators (STATCOM), and unified power flow controllers (UPFCs), controlled through a WACS, will facilitate more effective reactive power compensation and voltage control. Reactive power flows in the grid consume transmission capacity and limit the system's ability to move real power. Utilization of FACTS devices to minimize reactive power in the grid will allow SCE to maximize the amount of real power that can be transferred across congested transmission lines and thereby minimize transmission losses. Furthermore, manipulation of volt/VAR via networked FACTS devices could be used to actually change the impedance of a transmission line for enhanced direction of power flow. No new FACTS devices are planned to be put into operation during the 2011-2014 period. Looking beyond 2015, FACTS devices may allow SCE to relieve congestion on certain transmission corridors by rerouting power through parallel or interconnected lines. However, as timing and volume of deployments remain uncertain and future unit costs are unknown, SCE is unable to provide cost estimates for 2015-2020.

h) Once-Through Cooling (OTC) Mitigation Devices

Technologies for mitigating OTC-related challenges are still under investigation, but could include technology like synchronous condensers or other high inertia frequency regulation support devices, such as flywheels. Given the timing of the OTC policy requirements, SCE would have to deploy these solutions beginning in the 2016-2018 time frame.

i) Energy Storage

Energy storage is one potential technology that could help resolve issues related to integration of intermittent generation and transmission congestion. Wide-area control projects will include research into two areas of energy storage: bulk energy storage and distributed energy storage (DES).

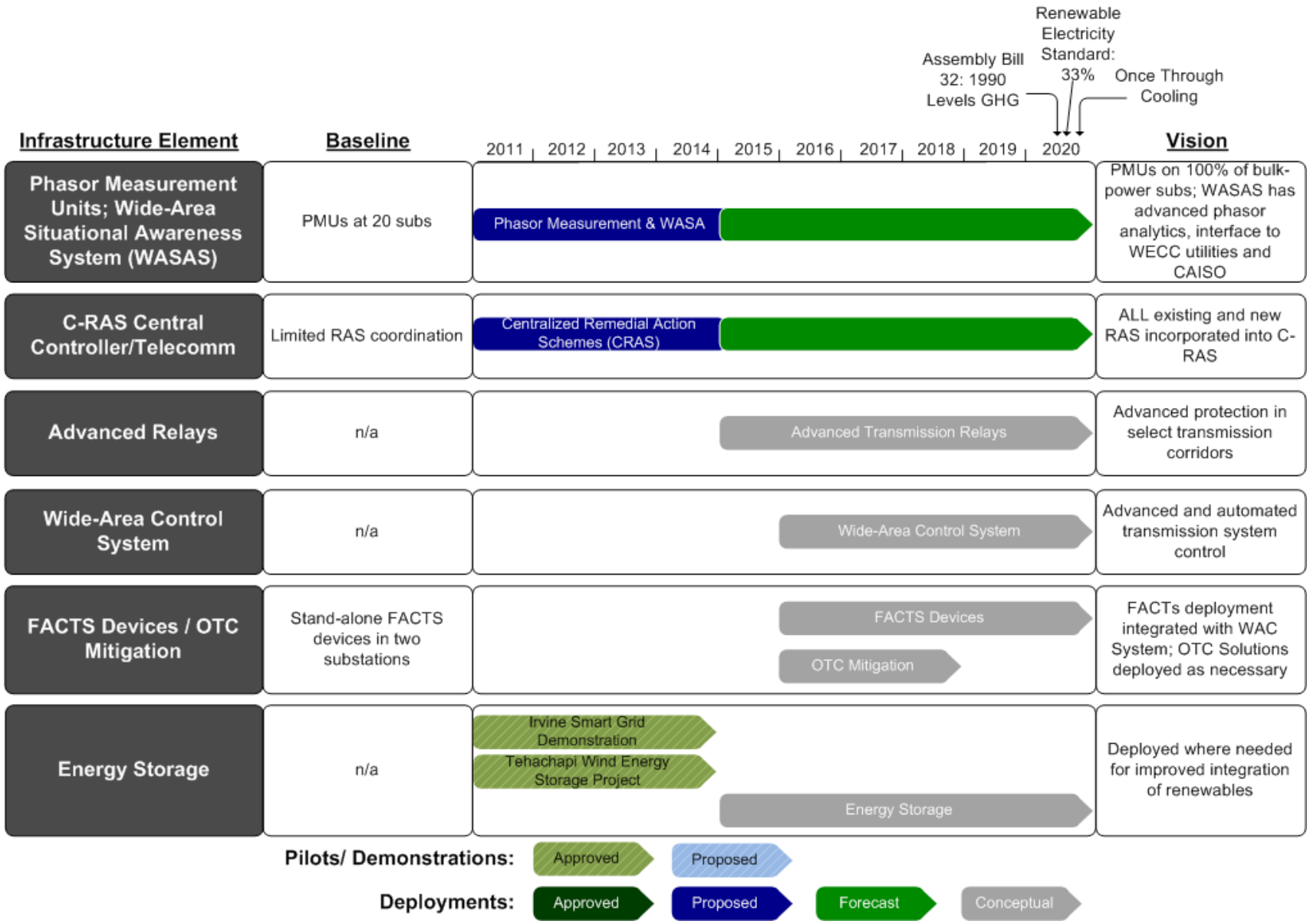
As discussed in the Distribution and Substation Automation Roadmap (Section V.G), SCE will conduct limited deployment of energy storage units with advanced inverter systems to address circuit overloading and voltage fluctuation at the distribution level, during the 2011-2014 time period. SCE does not currently have plans to significantly expand deployment of transmission or distribution sited energy storage beyond 2014. While continuing testing and evaluation of different storage technologies in the lab, SCE is also in the midst of rolling out two major ARRA-funded pilots or demonstration projects: (1) the ISGD project and (2) the Tehachapi Wind Energy Storage Project (TSP). Both of these projects will test specific applications of

energy storage so that the technology's ability to serve a particular operational use at a given location on the grid can be evaluated in real-world conditions. The information obtained from these pilots will inform future deployments by helping SCE to collect data on cost, performance, and grid impacts while also gaining experience in the installation, operation, and maintenance of said devices.

j) Summary

Figure 26 on the following page summarizes the baseline status of the infrastructure elements described above, planned deployments of this infrastructure between 2011 and 2020, and the future state vision for each of these infrastructure elements.

Figure 26 – Transmission Automation Baseline and Roadmap Summary



I. Asset Management Baseline and Roadmap

1. Baseline

SCE is in the early stages of deploying the infrastructure required to enable Advanced Equipment Monitoring. At the transmission level, SCE just began deploying dissolved gas analysis equipment and online bushing monitors at its bulk power system transformers through its Online Transformer Monitoring project.[132] As of December 31, 2010, SCE had installed this equipment at just one of the approximately sixty-eight 500 kV (AA) and 167 230 kV (A) transformer banks where it will ultimately be installed.

On the distribution side, SCE has developed a prototype of the monitoring equipment that it will look to eventually install on its approximately 700,000 distribution transformers in service.

The current status of the communications networks and management systems that support this capability are described in the Platform Investments section above.

2. Roadmap

SCE's plans for continued deployment of Online Transformer Monitors and Smart Distribution Transformers are described below.

a) Asset Management-Related Platform Infrastructure Deployments

Asset Management will leverage several platform infrastructure elements, including the high speed backbone, field area network, substation LAN, EMS, DMS, workforce computing devices, GIS, and cyber security. Information about deployments of this infrastructure is available in Section V.E.

b) Online Transformer Monitors

As noted above, SCE has targeted a total of 68 500-kV (AA) and 167 230-kV (A) transformer banks at 48 A and AA substations for deployment of online transformer monitors. As part of its Online Transformer Monitoring project,[133] SCE plans to deploy DGA technology and bushing monitoring devices on one AA substation and four A substations per year from 2011 through 2014. Total costs for this period, including equipment and installation, were estimated at $20.5 million ($2.5 million per AA substation and $560,000 per A substation in 2009 dollars).

132 *Ibid*,, Vol. 02, p. 78.
133 *Ibid*,.

SCE plans to continue deployment of DGA technology and bushing monitoring devices on five substations per year until all 48 have them. At this pace, deployment would be complete in 2020. Total costs for the 2015-2020 periods are estimated to be between $17 and $44 million.

c) Smart Distribution Transformer

As part of the Smart Distribution Transformers pilot project,[134] SCE will upgrade existing transformers on a limited scale (a total of 979 from 2012 to 2014), and then assess and verify their performance across the range of conditions in its service territory. Total cost for this pilot project is estimated at $2.1 million ($2,000 per transformer in 2009 $s).

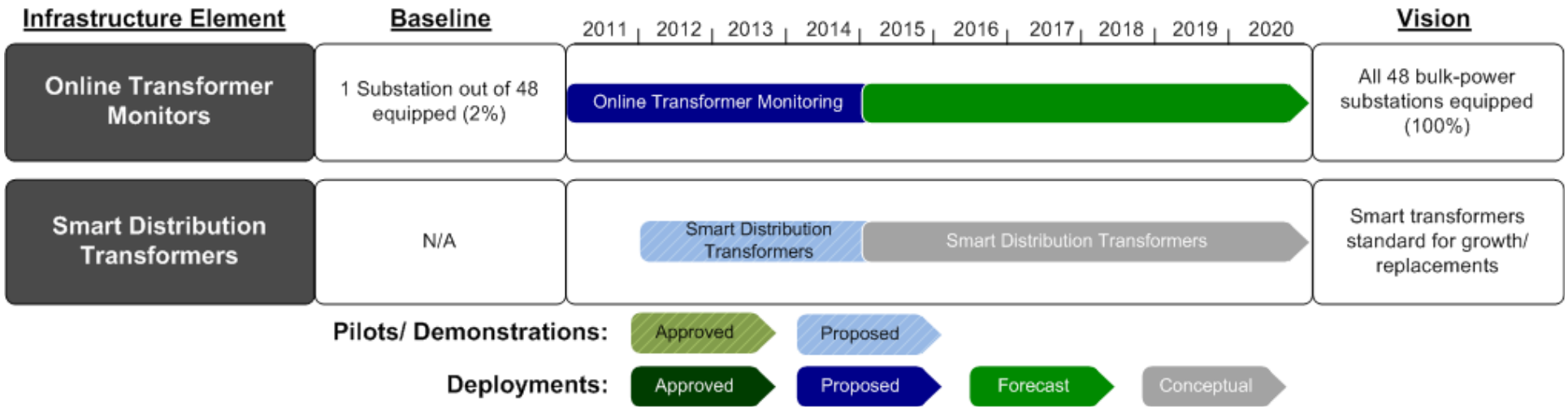
If the smart transformers perform as expected, they will gradually replace standard transformers. The pace of this transition will depend upon the performance of the new transformers and the trend in their cost. SCE expects the cost of these smart transformers to decline dramatically as the industry gathers more data about the performance of devices and standardizes their design.

d) Summary

Figure 27 summarizes the baseline status of the infrastructure elements described above, planned deployments of this infrastructure between 2011 and 2020, and the future state vision for each of these infrastructure elements.

134 *Ibid*,, p. 45.

Figure 27 – Asset Management Baseline and Roadmap Summary



VI. Cost Estimates

This chapter summarizes the cost estimates for the deployment projects and pilot projects described in the Deployment Baseline and Smart Grid Roadmap chapter above.

A. Estimating Methodology

For the 2011-2014 period, SCE's estimates are based on either:

- Approved funding for projects already authorized by the commission; or
- Proposed funding in applications pending before the commission.

Approved projects include SmartConnect, approved in D. 08-09-039. Proposed projects include pilot projects, platform infrastructure deployment projects, and smart grid incremental deployment projects from either SCE's 2012 GRC, SCE's 2012-2014 Demand Response Application, or SCE's Summer Discount Plan Application filed in June 2010.

For the 2015-2020 period, this chapter includes forecasts in the form of provisional cost ranges where available. These forecasts include a range of +/- 45 percent. SCE is able to provide provisional cost ranges for existing deployment projects where:

- The scope of the project is not likely to change;
- The technology is well-established; and
- Existing data and assumptions can be used to make projections.

Projects not meeting the above criteria have been labeled conceptual, and provisional cost ranges have not been provided at this time. These include existing technologies where the scope of future deployments is uncertain, as well as technologies that are not currently deployment-ready. The descriptions of each infrastructure element in the Deployment Baseline and Smart Grid Roadmap chapter above provide additional information about deployments for which SCE is not currently able to provide cost estimates. SCE may provide provisional cost ranges in future deployment plan updates as future technology solutions, time-frames, and costs become clearer.

Cost per customer is not provided in this Deployment Plan. Since some projects are conceptual and do not have cost estimates, an overall cost per customer would be incomplete. Furthermore, many smart grid investments are not made on a per customer basis, and therefore providing a cost per customer figure for specific projects would not be meaningful.

B. Scope of Included Costs

This chapter provides estimates of direct capital expenditures for the deployment of the infrastructure elements described in the Deployment Baseline and Smart Grid Roadmap chapter. For some infrastructure elements, certain O&M expenditures that are directly associated with the deployment of this infrastructure are also included.

This chapter also includes estimates of direct capital and O&M expenditures for the pilot projects included in the Roadmap discussion above. In addition, direct costs of all research, development, and demonstration activities performed by SCE's Advanced Technology Organization[135], as well as costs of the Emerging Markets & Technology activities described in SCE's 2012-2014 Demand Response application[136] are included.

The estimates below exclude the costs of projects funded in part or in whole by third parties, including the DOE-funded ISGD Project and TSP.

C. Summary of Cost Estimates

The table below summarizes 2011-2014 costs of infrastructure included in the Deployment Baseline and Smart Grid Roadmap chapter. The sections that follow provide further discussion of each of the three elements of this summary – approved projects, platform investments, and incremental smart grid investments. For each section, we provide project-level cost estimates for 2011-2014 and provisional cost ranges for 2015-2020 where available.

135 *Ibid*,, pp. 13-32, 103-109, 111-112.
136 SCE, 2012-2014 Demand Response Application, SCE-01, Vol-02, pp. 83-101.

Table 3 – 2011-2014 Cost Estimate Summary

Deployment Category	Annual Costs ($ million, nominal) 2011	2012	2013	2014	Total
Approved Projects:					
Edison SmartConnect™ Program	**$ 435**	**$ 368**	**$ -**	**$ -**	**$ 803**
Platform Investments:					
AMI Back Office Systems	-	-	31	17	49
Customer Information Systems/ SCE.com	25	53	51	35	163
Telecommunications Networks	7	18	48	89	161
T&D Management Systems	42	38	29	21	130
Cyber Security	-	8	8	12	28
TOTAL Platform Investments	**$ 73**	**$ 117**	**$ 167**	**$ 174**	**$ 532**
Incremental Smart Grid Investments:					
Customer Empowerment	27	58	16	15	116
Distribution & Substation Automation	5	25	26	27	82
Transmission Automation	68	46	42	30	186
Asset Management	5	5	6	7	23
Research, Development and Demonstration	33	32	32	32	129
TOTAL Incremental Investments	**$ 138**	**$ 165**	**$ 122**	**$ 110**	**$ 535**

1. Approved Projects

SCE's SmartConnect program, referred to in Section V.E, is related to the deployment of several infrastructure elements including Smart Meters, the AMI Network and Back Office Systems, a HAN, ALCS, Customer Premise Devices, and a Customer Data Warehouse.

Phase III of the Edison SmartConnect program was approved in D. 08-09-039, and is funded through the Edison SmartConnect Balancing Account. This decision approved $1,633.5 million in deployment period costs. The total remaining forecast of $803 million for 2011-2012 does not include $141 million remaining in program contingency.

2. Platform Investments

As described in the Deployment Baseline and Smart Grid Roadmap chapter, platform infrastructure elements are required to meet the needs of several smart grid capabilities and policy goals, but are also required for normal utility operations. Although the smart grid may require incremental investment in these infrastructure elements, it is difficult to attribute a portion of the cost of these investments to specific smart grid policy goals and value opportunities.

Below is a list of projects included in the Platform Investment totals shown above. The 2011-2014 costs are based on projects proposed in the 2012 GRC (with the exception of the EMS upgrade, which was approved in the 2009 GRC). Provisional cost ranges for 2015-2020 are also shown where applicable.

Table 4 – Platform Investment Project List

		($ million, nominal)					
Project Name	**Filing**	**2011**	**2012**	**2013**	**2014**	**Total**	**2015-2020**
AMI Back Office Systems:							
Enhanced Meter Usage & Capabilities Proj.	GRC	**$ -**	**$ -**	**$ 31**	**$ 17**	**$ 49**	N/A--Conceptual
Customer Information Systems/SCE.com:							
CSBU Customer Data Warehouse	GRC	-	9	9	9	26	N/A--Conceptual
Customer Relationship Management (CRM)	GRC	21	3	8	9	41	N/A--Conceptual
Customer Service System (CSS)	GRC	-	17	10	15	42	N/A--Conceptual
SCE Website (SCE.com)	GRC	4	24	24	3	55	N/A--Conceptual
		$ 25	**$ 53**	**$ 51**	**$ 35**	**$ 163**	
Telecommunications Networks:							
Distribution System Efficiency Enhancement Project (DSEEP)	GRC	5	5	5	6	21	N/A--Conceptual
Mobile Radio System Upgrade	GRC	-	2	8	20	30	no costs
SAS System Replacements	GRC	2	5	5	5	17	no costs
Substation Automation Integrating IEC 61850	GRC	-	3	7	8	18	60m to 159m
Next Generation Network -- SCEnet II	GRC	-	3	22	50	75	50m to 132m
TBD -- 4G Wireless/Sensor Network	TBD	-	-	-	-	-	N/A--Conceptual
		$ 7	**$ 18**	**$ 48**	**$ 89**	**$ 161**	
T&D Management Systems:							
Distribution Management System	GRC	12	9	7	1	28	N/A--Conceptual
DMS -- COTS Software	GRC	-	2	-	-	2	N/A--Conceptual
Outage Information	GRC	-	-	1	2	3	N/A--Conceptual
Outage Management System	GRC	-	2	-	2	4	N/A--Conceptual
Geographical Information Systems	GRC	18	23	18	10	69	no costs
Geographical Information Application System	GRC	-	-	-	2	2	no costs
Consolidated Mobile Solutions (CMS)	GRC	8	2	3	4	17	no costs
Energy Management System Upgrade	GRC	5	-	-	-	5	3m to 7m
		$ 42	**$ 38**	**$ 29**	**$ 21**	**$ 130**	
Cyber Security:							
Smart Grid Cyber Security	GRC	**$ -**	**$ 8**	**$ 8**	**$ 12**	**$ 28**	N/A--Conceptual

3. Incremental Smart Grid Investments

Projects classified as incremental smart grid investments tend to be specific to a smart grid domain and may serve one or more capabilities within that domain. As discussed in the Deployment Baseline and Smart Grid Roadmap chapter, these investments serve the policy goals and SB 17 characteristics identified for each domain.

Although some of these incremental projects are ongoing initiatives that have been in place for several years, such as the Circuit Automation program, most are defined projects that address a specific need. For example, the Dynamic Pricing project makes necessary changes to customer information systems to allow

for billing of new rates, and this effort will be completed in 2012. Other projects will not begin until after 2015 and are dependent on the results of current pilot projects as well as future technology developments.

Below is a list of projects included in the incremental smart grid investment totals shown above. The 2011-2014 costs are based on projects proposed in SCE's 2012 GRC, SCE's 2012-2014 Demand Response Application, or SCE's SDP Transition Application. Provisional cost ranges for 2015-2020 are also shown where applicable.

Table 5 – Incremental Smart Grid Investment Project List

		($ million, nominal)					
Project Name	**Filing**	**2011**	**2012**	**2013**	**2014**	**Total**	**2015-2020**
Customer Empowerment:							
Metering Capital Req. (2nd Meter for PEV)	GRC	1	2	3	4	**11**	N/A--Conceptual
Dynamic Pricing	GRC	17	16	-	-	**33**	no costs
Alerts and Notifications Project	GRC	-	9	7	4	**20**	no costs
PEV Support Systems	GRC	-	2	4	2	**8**	no costs
HAN Support & Troubleshooting	GRC	-	8	-	-	**8**	no costs
SDP Transition	SDP App	8	18	-	-	**27**	no costs
ALCS System Enhancements	DR App	-	-	-	2	**2**	N/A--Conceptual
Other Load Control System Enhancements	DR App	-	1	1	1	**3**	N/A--Conceptual
Smart Charging Plug-In Electric Vehicle Pilot	DR App	-	0	0	0	**1**	no costs
Workplace Charging Pilot	DR App	-	0	0	0	**1**	no costs
DR System Enhancements	DR App	-	0	1	2	**3**	N/A--Conceptual
Ongoing Customer System Enhancements	TBD	-	-	-	-	**-**	300m to 750m
TBD - ESPI Interface	TBD		N/A -- Conceptual				no costs
TBD - PEV Metrology	TBD		N/A -- Conceptual				N/A--Conceptual
TBD - Subtractive Billing	TBD		N/A -- Conceptual				no costs
		$ 27	**$ 58**	**$ 16**	**$ 15**	**$ 116**	
Distribution & Substation Automation:							
Integrated Smart Distribution	GRC	-	16	17	18	**51**	no costs
Circuit Automation	GRC	4	7	7	8	**26**	N/A--Conceptual
Capacitor Automation	GRC	1	1	1	1	**5**	5m to 14m
TBD - Distr Volt/VAR Devices	TBD	-	-	-	-	**-**	N/A--Conceptual
TBD - Distributed Energy Storage	TBD	-	-	-	-	**-**	N/A--Conceptual
		$ 5	**$ 25**	**$ 26**	**$ 27**	**$ 82**	
Transmission Automation:							
Phasor Measurement & WASAS	GRC	20	12	13	15	**59**	38m to 100m
Centralized Remedial Action Schemes	GRC	48	34	30	15	**127**	13m to 35m
TBD - Advanced Relays - Transmission	TBD	-	-	-	-	**-**	N/A--Conceptual
TBD - Wide-Area Control System	TBD	-	-	-	-	**-**	N/A--Conceptual
TBD - Transmission Energy Storage	TBD	-	-	-	-	**-**	N/A--Conceptual
TBD - FACTS Devices	TBD	-	-	-	-	**-**	N/A--Conceptual
TBD - OTC Mitigation Technology	TBD	-	-	-	-	**-**	N/A--Conceptual
		$ 68	**$ 46**	**$ 42**	**$ 30**	**$ 186**	
Asset Management:							
Online Transformer Monitoring	GRC	5	5	5	5	**21**	17m to 44m
Smart Distribution Transformers	GRC	-	0	1	1	**2**	N/A--Conceptual
		$ 5	**$ 5**	**$ 6**	**$ 7**	**$ 23**	
Research, Development and Demonstration:							
Advanced Technology Dept. O&M	GRC	15	16	16	16	**64**	N/A--Conceptual
PEV Readiness	GRC	9	5	5	5	**23**	N/A--Conceptual
RD&D Balancing Account	GRC	2	2	2	2	**8**	N/A--Conceptual
Advanced Technology Labs	GRC	3	6	7	7	**22**	N/A--Conceptual
CSBU Emerging Markets & Technology	DR App	4	2	2	2	**12**	N/A--Conceptual
		$ 33	**$ 32**	**$ 32**	**$ 32**	**$ 129**	

VII. Benefits Estimates

In this chapter, SCE provides a description of the benefits that it expects to achieve by pursuing each smart grid capability. The organization and presentation of benefits is consistent with guidance provided in D. 10-06-047 which identifies three smart grid benefit categories: (1) achievement of policy requirements, (2) benefits beyond simple compliance with a regulatory requirement, here called economic benefits, and (3) other benefits like reliability and safety that are difficult to quantify.[137]

Throughout this document, SCE has divided its discussion of smart grid infrastructure deployments between platform and incremental infrastructure. Making investments in platform infrastructure that will enable smart grid capabilities is a critical step in bringing about a smart grid. As these investments support many capabilities, and in most cases also support core utility functions, SCE does not apply a direct cost/benefit analysis to each of these investments. Rather, SCE views the benefits of identifying and appropriately designing platform infrastructure in terms of preserving options with respect to future incremental investments and avoiding future integration costs. This platform infrastructure allows SCE to make targeted deployments that will provide best-fit solutions to challenges associated with specific energy policies, or cost effectively deliver benefits to its customers.

The discussion below of benefits in the areas identified in D. 10-06-047 is meant to provide guidance about the value of incremental investments that will leverage the foundation provided by platform investments. In the near-term, these benefits mainly relate to AMI-enabled DR and conservation, and enabling renewable energy policy goals. Over time, SCE expects to unlock additional value – perhaps in ways that it cannot foresee today – by continuing to build a platform and making incremental investments when technologies are sufficiently mature and understood to deliver expected benefits.

A. Customer Empowerment

Deployment of infrastructure supporting capabilities within SCE's Customer Empowerment domain—i.e., DR, Enhanced Customer Engagement and PEV Integration—will significantly enhance the way in which customers manage their energy usage. When approached in an integrated fashion, these capabilities will help to achieve important policy goals while also providing economic savings and significant benefit to customers, utilities, and society at large.

Smart grid-enabled DR programs and tariffs combined with adoption of energy management devices will empower customers to receive and access more granular and meaningful electricity usage information, including the present price and total cost of that consumption to date. Better information along with

137 D. 10-06-047, p 74.

automated energy management or control will allow customers to optimize their usage to meet their particular needs or, alternatively, the needs of the grid providing that electricity. This is a significant departure from how electricity is currently used. Overall, this domain encapsulates several benefits including reductions in peak demand and associated costs, increased conservation, increased system reliability, enhanced customer service and the integration of demand side resources with wholesale markets.

1. Policy Achievement

Smart Grid capabilities included in the Customer Empowerment domain are required to achieve several major energy and environmental policy goals as described below:

a) California's Energy Action Plan, EAP II and Public Utilities Code Section 454.5

All of these policies require that the state's utilities pursue some combination of DR, dynamic pricing and TOU rate programs as a way to encourage DR and support GHG reduction goals. Section 454.5 of the California Public Utilities Code requires that a utility "first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible."[138] SCE is working to fulfill these objectives by engaging customers in active energy management, educating customers about the time sensitivity of energy use and pricing, and conducting outreach so that customers take advantage of dynamic pricing tariffs and other DR programs.

b) Smart Grid OIR / D. 09-12-046

Infrastructure deployed to enable SCE's Enhanced Customer Engagement capability is required to meet the requirements of D.09-12-046, including (1) secure provision of customers' electricity usage information to an authorized third party and (2) customer access to smart meter usage data on a real-time or near real-time basis.[139]

c) AB 32

Decreased energy consumption from enhanced conservation, load management and PEV integration will provide direct GHG reduction in support of California's landmark legislation on climate change. SCE's DR programs further decrease emissions by avoiding on-peak energy production, which is typically served

138 Pub. Util. Code § 454.5(b)(9)(C), http://law.onecle.com/california/utilities/454.5.html.

139 See D. 09-12-046, Ordering Paragraphs 3 and 4, http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/111856.pdf.

by inefficient and highly carbon intensive gas turbines. Finally, energy savings provided by demand-side resources again reduce GHG emissions associated with T&D line losses; these savings can be especially significant during peak periods as high temperatures and system constraints result in greater line loss.

d) PEV Policies

Federal and state policies such as Executive Order S-1-07, AB 1007 (Paley), and California's Alternative Fuels Plan are driving adoption of roughly 100,000 vehicles in SCE's service territory by 2015. PEV Integration is required to fulfill the objectives of these policy goals by supporting PEV adoption while avoiding any adverse reliability impacts and maximizing the environmental benefits that these vehicles can provide.

2. Economic Benefits

Customer Empowerment-related capabilities will reduce peak demand and decrease energy consumption, providing substantial economic benefit in the form of avoided energy and capacity costs. Customer education and outreach is key in realizing the benefits of these capabilities as desired energy savings and peak reduction are dependent on the number of customers that take advantage of newly enabled time-variant rates, DR programs, and energy information services.

a) Peak Demand Reduction and Avoided Costs Enabled by DR

Avoided capacity procurement costs represent one of the primary economic benefits provided by DR capabilities within SCE's Customer Empowerment domain. As documented in its most recent 2012-2014 DR funding application, SCE estimates that its portfolio of dynamic pricing and event-based DR programs will grow from the existing 1,530 MW to nearly 1,900 MW by 2014 as a result of increased enrollment and new SmartConnect enabled programs. Because of market integration initiatives and deployment of SCE's SmartConnect meters[140], price responsive DR will for the first time be SCE's primary method of delivering DR and will represent approximately two-thirds of SCE's DR portfolio by 2014.

Economic or market-based dispatch of DR resources on a more localized basis will result in increased and more cost-effective utilization of these resources where they are needed most. DR-enabled load reduction also provides economic benefit in the form of energy savings from decreased consumption during events, improved utilization of transmission and distribution assets, avoided line loss, decreased congestion charges, and avoidance of significantly higher wholesale electricity costs during critical peak periods.

140 SCE's Smart Connect meters provide interval usage data that is required for CAISO settlements. Information provided by these meters is necessary for certain programs (such as SCE's Summer Discount Plan), to be transitioned to price responsive dispatch and integrated with CAISO markets.

b) Energy Savings Obtained through Enhanced Conservation

Enhanced conservation enabled by direct feedback of detailed energy usage information represents the most significant and readily achievable economic benefit provided by SCE's Enhanced Customer Engagement capability. This benefit is realized by (1) provision of day-after, hourly energy usage data to customers over the internet and (2) provision of energy usage data via the HAN in near real-time (every 7 seconds). Potential energy savings are here based on the simple premise that customers use less when they know more about their actual usage. This premise has been validated in numerous studies and real-world pilots. For instance, a 2006 pilot project conducted by Hydro One attributes 6.5 percent energy savings to the deployment of real-time, home energy monitors in Ontario, Canada.[141] An extensive review of energy feedback related studies supports an energy savings potential of 5 to 15 percent.[142] Consistent with its AMI Business Case, SCE assumes that customers accessing day-after energy usage data over the internet will reduce their consumption by 2 percent and that customers provided with more real-time data via the HAN will achieve, on average, 6.5 percent energy savings. SCE thus estimates that in 2014, customers will be conserving and ultimately avoiding the cost of over 250,000 MWh per year of electricity.

c) Reduced System Costs and Improved Utilization of Distribution Assets from PEV Integration

PEV Integration will provide significant economic benefit through reduced system energy and capacity procurement costs as well as improved utilization of T&D assets. Based on recent forecasts, SCE expects to see approximately 450,000 PEVs in its service territory by 2020.[143] Managing PEV load to reduce the on-peak charging of these vehicles, through TOU rates or future DR programs, will decrease coincident peak loading and avoid system energy costs.

Depending on the level of charging, the PEV load for one vehicle can be greater than that of an entire household. This can cause localized impacts on distribution infrastructure. If left un-managed, PEV load could reduce the operational life span of transformers and potentially cause critical overloading conditions that may result in premature failures due to overheating. Enhanced notification of PEV installations coupled with time-variant PEV rates and load management capabilities will decrease strain on SCE's distribution infrastructure and provide economic benefit through improved utilization of existing T&D assets.

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141 D. Mountain, Mountain Economic Consulting and Associates, Inc., The Impact of Real-Time Feedback on Residential Electricity Consumption: The Hydro One Pilot (2006).

142 Sarah Darby, The Effectiveness of Feedback on Energy Consumption: A Review of DEFRA of the Literature on Metering, Billing, and Direct Displays (Environmental Change Institute, University of Oxford, UK: April 2006).

143 Based on mid-case scenario. SCE's 2012 GRC Phase 1 Application, SCE 03, Vol. 2, Advanced Technology, p. 17.

3. Other Benefits

a) Increased System Reliability

SCE's Smart Grid will receive more accurate and timely information about unexpected events that threaten the local grid zones and SCE will be able to respond more quickly and effectively with DR dispatching to address the resource needs. Further, by 2014, SCE will be able to bid approximately 1,360 MW of its DR resource portfolio in the CAISO markets with full locational dispatch capability.

Smart grid-enhanced DR program deployment will enable SCE to respond to localized events or threats to the grid by employing a more targeted and localized response to the event, without impacting customers outside of the affected area. The ability to dispatch reductions in peak demand during critical events will contribute to numerous system and customer benefits. One of the most significant is an increase in grid system reliability resulting from more stable demand.

A portfolio of price-responsive DR programs that can be launched on a day-ahead or day-of basis mitigates the need for rotating outages that might otherwise occur. This earlier mitigation avoids the inconvenience of firm load interruptions to customers and also the potential economic loss of business by SCE's C&I customers. Furthermore, SCE will have higher quality grid-level data that will enable SCE to identify or predict potential strains on the infrastructure and to take localized and targeted DR action before a problem occurs. This targeted approach should also result in cost reductions because it is far more expensive for SCE to react to infrastructure problems than it is to pro-actively address potential problems.

PEV Integration will also help to avoid localized reliability impacts associated with incremental PEV load. If left unmanaged, PEV charging may cause critical overloading conditions which would result in in-service equipment failure and consequent customer outages. These impacts are even more pronounced when customers charge on-peak or when PEVs cluster on aging circuits ill-equipped to accommodate this new load. PEV load management via TOU rates and/or event-based programs can mitigate increased levels of strain and potential overheating or failure of distribution infrastructure, primarily secondary transformers. PEV integration thus provides substantial benefit by helping to mitigate overloading of distribution infrastructure, avoid subsequent outages, and maintain adequate levels of reliability as PEV adoption continues to increase in SCE's service territory.

b) Enhanced Customer Satisfaction

The combination of new and enhanced customer programs, products and services, together with the customer's own technology-enabled capabilities, are expected to result in increased levels of customer satisfaction with the delivery of their electricity. With thoughtful engagement by SCE, customers will adopt and benefit from the enhanced functionalities brought by the smart grid as they are unfolded. As

customers learn more about the features of the smart grid as well as the various devices, they will prefer the experience of having increased information, control and choices involving their use of electricity.

B. Distribution & Substation Automation

Deployment of infrastructure to support the capabilities in SCE's Distribution and Substation Automation domain will provide an integrated platform that enables DG programs, enhances outage response and service restoration, and improves power quality while making the distribution grid more efficient. DER Integration, Advanced Outage Management, and Advanced Volt/VAR Control will fundamentally enhance day-to-day operation of the distribution system to enable progressive energy policy goals and provide benefit in the areas discussed below.

1. Policy Achievement

The capabilities in the Distribution and Substation Automation domain are required to enable major energy policies associated with the deployment of DG, and will support SCE's progress towards other policies targeting the reduction of greenhouse gases.

a) DG Programs & ZNE Homes

As discussed in Section III.A.2.d), California has made deployment of DG facilities an important policy goal. A variety of incentives and programs will lead to increasing interconnection of distributed renewables on SCE's distribution system during the period covered by the Deployment Plan. To safely accommodate these interconnections, SCE must enable the DER Integration capability, which will leverage many common infrastructure elements with the other capabilities in this domain. SCE's DER capability will allow for full deployment of PV under CSI as well as full achievement of other programs that will drive DER deployment such as SGIP, Net Surplus Compensation, SCE's Solar Photovoltaic Program and ZNE Homes.

b) AB 32 & RPS

In addition to meeting the basic need to safely accommodate DG, the capabilities in this domain will also support SCE's progress towards other important state energy policy goals like GHG reductions under AB 32 and achievement of the 33 percent renewable portfolio standard. AV/VC will increase efficiency across the entire distribution system, providing GHG reduction through reduced MWh consumed by SCE's customers. Similarly, integrating DERs can help offset GHG emissions that would otherwise be produced

by higher carbon generation and, in certain cases, support SCE's procurement of renewable power that will count towards SCE's RPS requirement.

2. Economic Benefits

Capabilities in the Distribution and Substation Automation domain will also achieve economic benefits by reducing energy and capacity costs through energy savings.

As discussed in Section V.B.3, delivering voltage at the lower end of the allowable range can produce substantial energy savings. A DOE bottoms-up evaluation of AV/VC at the national level found that complete deployment of this capability could reduce annual energy consumption by as much as 3 percent when implemented on all distribution feeders across the country.[144] SCE has been assessing the potential of AV/VC to achieve energy savings in its own service territory since the early 1990s. Based on the results of this research, SCE estimates that AV/VC could reasonably achieve a 1-2 percent voltage reduction on targeted circuits, resulting in energy savings of 1-2 percent for customers served by those circuits. If SCE were to fully implement AV/VC on all applicable distribution circuits, SCE conservatively estimates that it could save 700,000-1,400,000 MWh per year. Realization of this benefit will begin when the DMS upgrade is complete and will ramp up over time as more substations are automated. These savings allow SCE to decrease expenditure on procurement of wholesale energy, ultimately providing real financial savings to customers.

3. Other Benefits

In addition to the policy compliance and cost-saving opportunities discussed above, capabilities in the Distribution and Substation Automation domain provide a host of non-economic benefits that will enhance customer service, improve reliability, and reduce the environmental impact of electricity delivered by SCE. The following benefits represent a substantial driver of smart grid investments within this domain:

a) Enhanced Safety and Reliability

Advanced Outage Management will provide enhanced reliability through continued implementation of circuit automation and future deployment of self-healing circuits. Table 6 below shows the average reductions in both CMI and Part Load Up Time[145] for circuits automated between the years 1993 and 2004.

144 U.S. Department of Energy, Evaluation of Conservation Voltage Reduction on a National Level (July 2010).

145 Customer Minutes of Interruption measures the total duration of customers' outages while Part Load Up Time measures the time it takes to actually restore power to those customers on the section of the circuit that is separated from a fault.

SCE's automation of these circuits has achieved an average of 33 minutes of reduction in Part Load Up time and an 18,949 reduction in CMI. These reductions help SCE maintain appropriate system reliability, particularly in light of increased equipment failures on its aging system.[146] Looking forward, SCE is conducting limited deployment of advanced circuit automation technologies to create self-healing circuits that can provide even faster fault isolation than its existing programs.

Table 6 – Reductions in Average Customer Minutes of Interruption (CMI) and Part Load Up Time for Circuits between 1993 and 2004

	Average CMI	Average Part Load Up Time
3 Years Prior to Automation	108,318	70
3 Years After Automation	89,368	37
Average Reduction	18,949	33

The Advanced Outage Management capability also promotes public and employee safety. Downed power lines can leave customers and employees exposed to unsafe and even life-threatening conditions. Automated fault isolation enabled by the Advanced Outage Management capability can help mitigate these safety risks. For instance, should a tree limb fall on a line or a car crash into a distribution pole, automated or self-healing circuits would de-energize that portion of the circuit which would otherwise pose serious risks to customers and employees. Enabling this capability is therefore critical to SCE's efforts to provide safe electric service.

b) Improved Power Quality

Both AV/VC and DER Integration will improve the quality of power SCE delivers to its customers. Rapid swings in output from renewable generators can cause voltage on distribution circuits to drop (or rise) quickly, making it difficult for SCE to ensure that customers receive electricity within required voltage limits.[147] For instance, due to passing cloud formations, PV output can drop from 100 percent of capacity to 30-40 percent within a minute.[148] Implementation of automated and fast-acting power supply devices as part of SCE's AV/VC and DER Integration capabilities will allow SCE to better manage these rapid and unpredictable voltage fluctuations, thus improving power quality on circuits with high penetrations of PV.

146 SCE began the Outage Database and Reliability Metrics (ODRM) method of accounting for SAIDI, SAIFI and MAIFI in January 2006. Therefore, the first opportunity to provide the "three years prior versus three years after automation" calculation, using this new methodology, will be 2012.

147 Under industry standards reflected in SCE's Tariff Book Rule 2 (available at http://www.sce.com/AboutSCE/Regulatory/tariffbooks/rules), SCE is required to deliver electricity to customers within a set 114-120 volt range to protect customer owned-equipment.

148 KEMA, CPUC California Solar Initiative 2009 Impact Evaluation (June 2010).

c) Enhanced Customer Satisfaction

Finally, both DER Integration and Advanced Outage Management will increase customer satisfaction by accommodating different generation options for customers and decreasing the total amount of time customers go without service during outages. DER Integration provides customers with more choice and flexibility regarding the production of energy and the type of energy they would like to consume. Advanced Outage Management should further improve customer satisfaction by decreasing the duration and number of customers affected by unavoidable, emergency outages.

C. Transmission Automation

Transmission Automation encompasses infrastructure deployments that will enable three tightly integrated capabilities of Wide-Area Monitoring, Protection, and Control. In aggregate, these capabilities will dramatically enhance day-to-day operation as well as long-term planning of the transmission system to address challenges posed by progressive environmental policy goals. Enhanced reliability and improved utilization of transmission assets represent foundational benefits achieved through WAMPAC.

1. Policy Achievement

Transmission Automation supports major environmental policies that are significantly changing SCE's generation portfolio and, by consequence, creating operational challenges on the transmission system. These policy driven issues dictate the need for advanced WAMPAC capabilities as discussed below.

a) AB 32 / RPS

Increasing procurement of bulk renewable resources under California's RPS mandate represents a major challenge for ongoing operation and planning of SCE's transmission system. The capabilities provided by WAMPAC are required to address the issues associated with safely and cost-effectively interconnecting many new renewable generation facilities as well as reliably integrating intermittent output from those facilities. WAMPAC will significantly reduce GHGs by (1) enabling robust and sophisticated protection schemes needed to safely connect renewable generation facilities and (2) monitoring or managing reliability impacts associated with the intermittent output of these renewable resources. With these capabilities in place, SCE expects to provide roughly 28 million MWh of clean, zero-carbon electricity by 2020 in complying with the 33 percent RPS goal. Wide-Area Control has the potential to further reduce GHGs through utilization of energy storage technologies to firm or balance variable renewable generation. Although still in demonstration, the use of energy storage in such applications would displace emissions from gas turbines that typically provide fast-responding, ancillary services.

b) Once Through Cooling

As discussed in Section III.A.2.c), OTC requirements will result in substantial loss of in-basin generation resources[149]. The capabilities provided by WAMPAC are required to address voltage stabilization issues resulting from generation retirement as well as problems with inadequate transmission capacity needed to deliver electricity from alternate geographic regions.

2. Economic Benefits

Transmission Automation will create an infrastructure platform supporting improved transmission asset utilization and reduced transmission congestion charges. Wide Area Monitoring will allow system operators to increase power flow across transmission assets while monitoring operating conditions in real-time to help ensure system stability. When coordinated on a wide-area basis (i.e., with WECC, CAISO, neighboring utilities), this PMU-enabled capability can dynamically optimize transmission line ratings according to system conditions at that time, allowing operators to utilize transmission capacity that was previously restricted by static line ratings. EPRI indicates that dynamic line ratings could provide 5-15 percent more transmission capacity than static ones.[150] A joint PIER-funded study conducted by SDG&E and the CEC demonstrated that real-time transmission line ratings realized 40 to 80 percent more power transfer capacity than the static ratings previously allowed.[151]

Optimized utilization of transmission assets in this manner can provide substantive benefit in reducing transmission congestion charges that are incorporated in the wholesale price of electricity. In California markets, transmission congestion charges occur when scheduled transactions (generation and load) results in power flow over a transmission line that exceeds the available capacity for that line. Because grid operators have to avoid physical overloads to ensure safety and reliability, they may have to dispatch a more expensive generator on the demand side of the line. In these situations, the difference in cost between the more expensive generator and the less expensive (but more remote) generator is the congestion cost. The ability to increase the rating of a transmission line dynamically in response to actual grid conditions could free up unused transmission capacity, thus avoiding or reducing congestion charges and decreasing overall spending on wholesale power procurements. These savings would ultimately be passed along to ratepayers.

149 "In-basin" generation refers to generation units within or close to the Los Angeles basin, SCE's primary load center.

150 EPRI, Estimating the Costs and Benefits of the Smart Grid p. 5-4 (March 2011).

151 William Torre, "Dynamic Circuit Thermal Line Rating" (California Energy Commission-PIER Strategic Energy Research, October 1999).

3. Other Benefits

While the capabilities within Transmission Automation are primarily driven by the need to comply with energy and environmental policy goals, this domain also provides other benefits to customers and society at large as discussed below.

a) Enhanced Safety and Reliability through Monitoring and Avoidance of Large-Scale, Cascading Outages

SCE's WAMPAC capability should improve reliability on a tightly interconnected and constrained bulk power system that must accommodate increasing variability from renewable generators. Armed with information on real-time operating status of the grid, system operators will be able to take proactive measures needed to avoid large-scale blackouts before the system reaches a breaking point. The benefit of wide-area monitoring and situational awareness is exemplified by instances such as the 2003 blackout across Canada and the eastern United States. This outage affected an estimated 50 million people and lasted 4 days in some parts of the U.S., incurring estimated costs between $4 billion and $10 billion in the U.S. alone. The U.S.–Canada Power System Outage Task Force issued a final report which states, "[t]he need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations."[152] Their study calls for development of synchrophasor based applications for wide-area monitoring and further concludes that "improved visibility of the status of the grid beyond an operator's own area of control would aid the operator in making adjustments in its operations to mitigate potential problems."[153]

D. Asset Management

Smart grid deployments will fundamentally enhance the way SCE maintains and replaces infrastructure on the transmission and distribution system. SCE's Asset Management domain includes Advanced Equipment Monitoring and Workforce Automation capabilities which will allow SCE to avoid costly emergency replacements while providing other benefits for customers and employees.

1. Economic Benefits

Advanced Equipment Monitoring will provide economic benefit by helping SCE to avoid costly catastrophic equipment failures. In-service failure of critical infrastructure can result in extensive

152 U.S.-Canada Power System Outage Task Force Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, p. 159 (April 2004).

153 *Ibid*. pp. 159-160.

collateral damage and is substantially more expensive than proactive infrastructure replacement. In 2003, for example, a distressed asset at SCE's AA Vincent Substation caused a fire which destroyed three transformers, melted the supporting steel structure of the transformer bank, and irreparably damaged multiple reactors. The fire had to be contained and the infrastructure replaced as soon as possible—resulting in a total cost of $20 million compared to the $3 to 5 million cost of a planned transformer replacement. With implementation of Advanced Equipment Monitoring, SCE will have access to real-time information about the status and health of critical infrastructure so that equipment condition can be continuously assessed and preventative maintenance or replacement employed when needed. This capability will help SCE avoid the costs and negative impacts of catastrophic equipment failures.

2. Other Benefits

The ability to better manage transmission and distribution assets and avoid in-service equipment failures will not only reduce costs, it will also provide improved safety, reliability, and an enhanced customer experience as described below.

a) Enhanced Safety and Reliability by Avoiding In-Service Equipment Failures

In-service equipment failures not only cost more to fix, but they can also result in prolonged service interruption or even wide-scale outage and can pose potentially fatal hazards to customers and employees. Failure of a transformer, as previously discussed, can result in oil spills and serious fire hazards. Advanced equipment monitoring will give SCE personnel the information needed to help prevent such failures, thereby reducing outage times and safety hazards.

b) Improve Customer Satisfaction

Proactively managing infrastructure replacement via enhanced equipment monitoring will also give SCE control over when outages are scheduled. Replacement work can be scheduled for times of day (e.g. during the work day for residential customers) or time of year (e.g. in advance of summer peaks) that pose the least inconvenience to customers.

E. Summary

Smart grid infrastructure deployments included in this plan enable a variety of capabilities that benefit the utility, its customers, and society at large. At a high level, SCE's benefits are derived from the combined effort to comply with energy and environmental policies, realize new value opportunities, and enable

characteristics specified in SB 17. This discussion is not meant to provide a comprehensive list of potential benefits, but rather an overview of those benefits that currently appear to be readily achievable and that are of high priority to SCE. The economic benefits quantified in this chapter and summarized here represent instances where smart grid capabilities and their associated benefits had been assessed through prior demonstration or verified by external studies and where the scale and scope of the deployment was well-defined. In the end, one of the smart grid's greatest benefits will be to act as an accommodating platform for technological innovations that will enable new products, new services and even greater value in years to come.

VIII. Grid Security and Cyber Security Strategy

This chapter describes SCE's existing grid and cyber security practices, as well as its plans for updating its grid and cyber security strategy as threats in both of these areas evolve over time with introduction of smart grid technologies. Critical infrastructure owned and operated by utilities form a high priority target for attacks aimed at disruption, intelligence collection, and intellectual property theft. As one indicator of the amount of sustained threats, SCE's information security tools and processes block over half-a-million intrusion attempts per year at SCE's network perimeters. As the electric grid becomes smarter and more interconnected, and utilities depend increasingly on mobile and wireless technologies, e-commerce, remote access, and social media, these threats will increase.

Policy makers and other smart grid stakeholders have rightly focused on cyber security as an important aspect of smart grid deployment. To address the complex, persistent, as well as potentially destructive threats associated with cyber attacks, and to comply with a growing number of cyber security and privacy laws, SCE takes a comprehensive, holistic approach to cyber security.

Section A below describes this approach and discusses the guidance documents, threat assessments and other considerations that inform SCE's grid and cyber security strategy. Section B deals more specifically with Customer Privacy and Data issues that the Commission has asked SCE to address in D. 10-06-047.

A. SCE's Cyber Security Strategy

In this section, SCE presents its approach to cyber security, its threat assessment and mitigation practices, and the guidance documents that inform its security strategy. This section also includes a description of the approach SCE took to building cyber security into its advanced metering solution as an example of how its processes can work effectively.

1. Multi-layered, Defense-in-Depth Cyber Security Program

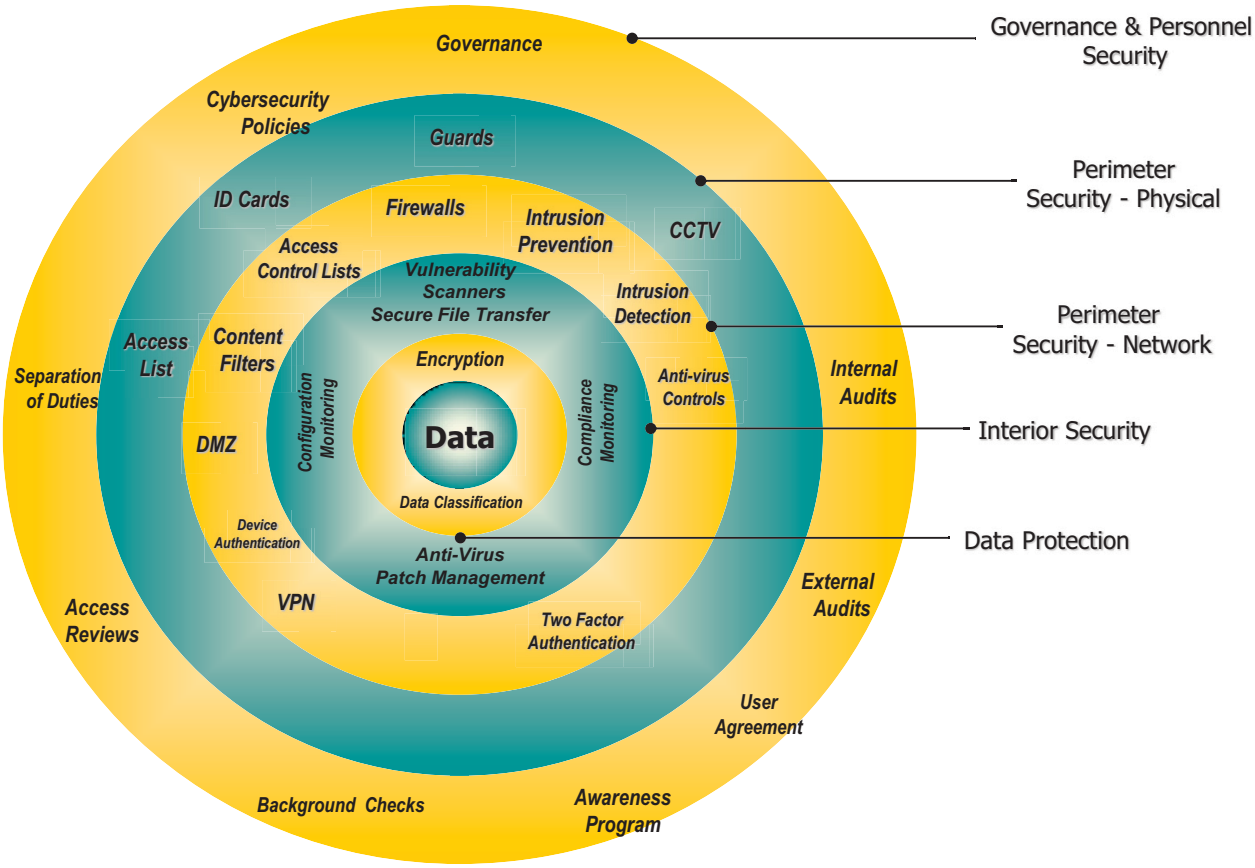
The foundational element of SCE's approach to cyber security is a multi-layered, defense-in-depth strategy that provides integrated system-wide and asset-specific protection through multiple layers of technology procedures and controls. This approach, depicted in Figure 28 on the following page, addresses physical, cyber and human threats to provide end-to-end security.

At the governance level, cyber security policies, user agreements, internal and external audits, background checks, access reviews, vulnerability assessments, and awareness programs are in place. At the perimeter security level, there are layered controls, such as anti-virus software, intrusion prevention and detection

firmware, firewalls, access control lists, content filters, two-factor authentication, and Virtual Private Networks (VPN).

Additionally, data protection controls include encryption, vulnerability scanners, configuration management, data classification schema, and anti-virus and anti-malware patch management.

Figure 28 – SCE's Multi-Layered, Defense-In-Depth Strategy



The sections that follow provide additional details about the components of SCE's Defense-in-Depth strategy.

a) Risk-Based Security Levels

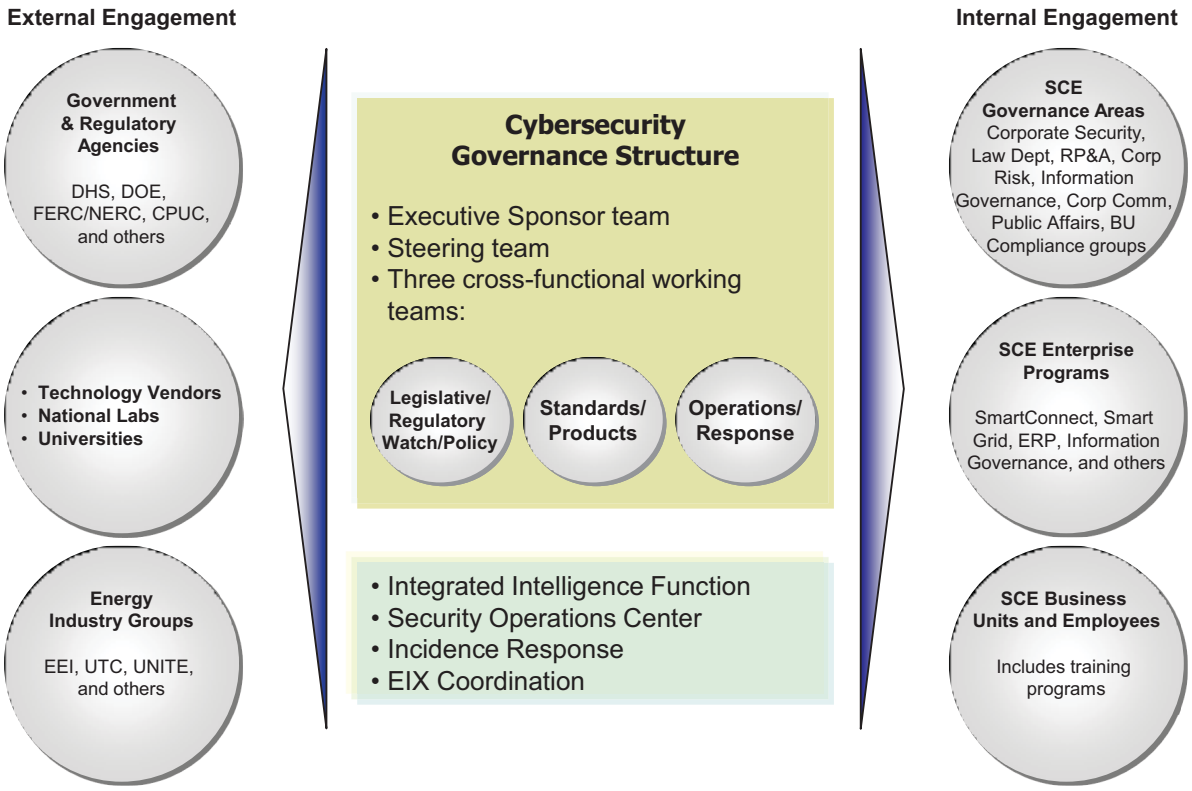
SCE uses multiple levels of security based on criticality and risk. These include:

- Minimum security - for the Internet and public-facing systems
- Medium security - for the administrative network and normal (non-critical applications) business use
- High security - for critical business use
- Maximum security - for critical infrastructure applications, such as NERC Critical Infrastructure Protection (CIP) and NRC systems required per cyber security requirements

b) Governance Model

SCE has implemented a robust information security program governance model. As shown in Figure 29 below, this model is characterized by executive-level sponsorship, partnerships with external stakeholders, and cross-functional teams working with internal stakeholders across the company.

Figure 29 – SCE's Cyber Security Governance Model



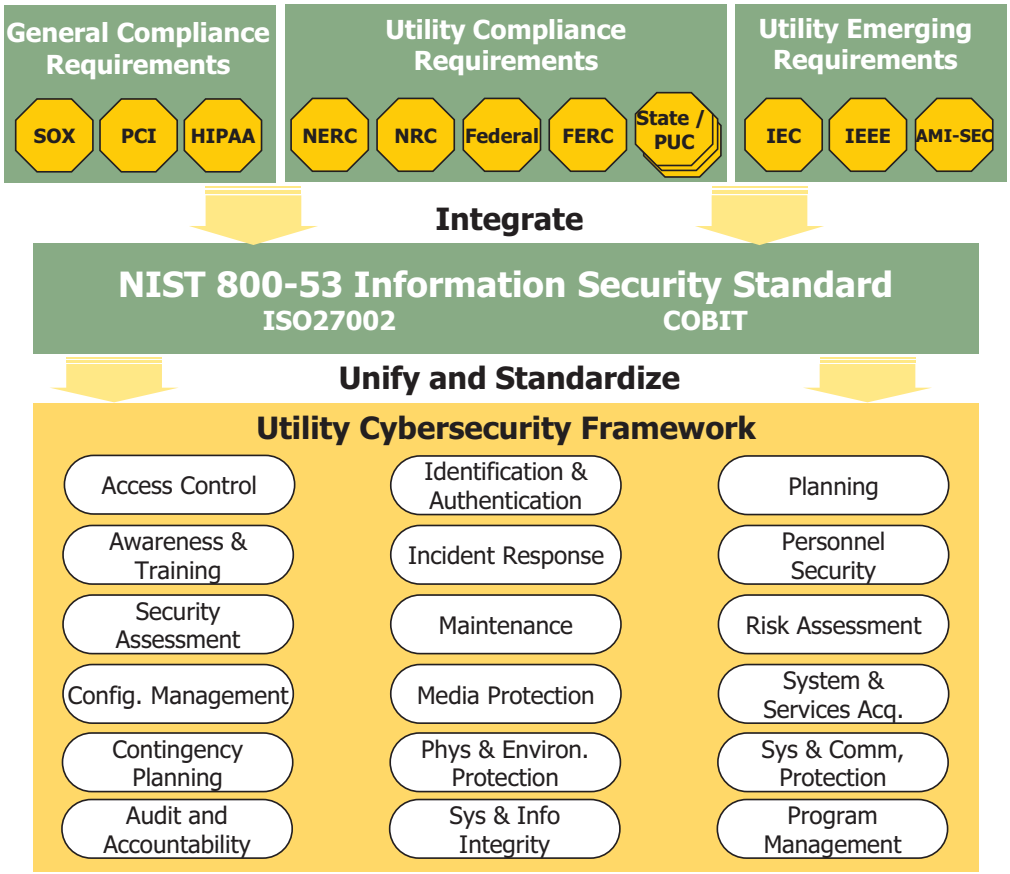
c) Cyber Security Framework

SCE has leveraged the NIST (National Institute of Standards and Technology) 800-53 Information Security Standard in development of its Cyber Security Framework, as shown in Figure 30 below.

Inputs to the framework include general compliance requirements, specific utility compliance requirements, and emerging utility requirements. These requirements have been integrated with NIST 800-53, ISO (International Standards Organization) information security standards, and the COBIT (Control Objectives for Information and related Technology) framework for IT management and governance. Together, these have been unified and standardized into SCE's cyber security framework, which is composed of the NIST-defined 17 security control families.

This framework provides mappings of all security requirements and defines relevant and actionable controls supporting a wide variety of needs from applicable utility regulations (i.e., NERC CIP, NRC, PCI, and Smart Grid). For each control family (or category) within the framework, there are multiple controls to address SCE's various regulations and mandates. For every control, there are specific requirements and secure solution sets that are required for implementation in order to comply with standards, regulations, and mandates.

Figure 30 – SCE's Cyber Security Framework

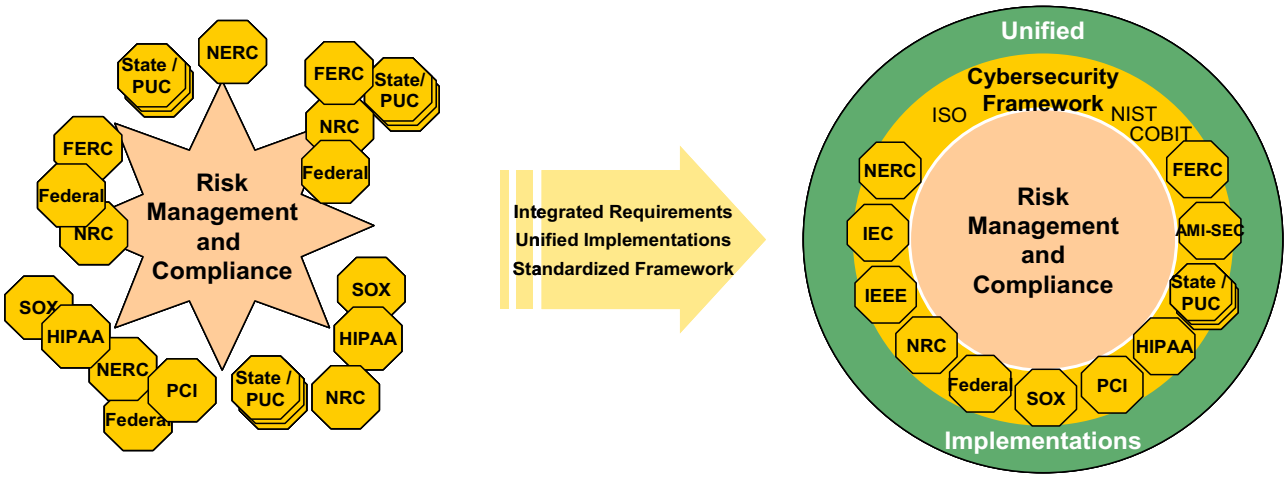


d) Portfolio-based approach to security-related requirements

SCE has adopted a portfolio-based approach to security assurance, as shown in Figure 31 below.

By integrating multiple (and often related) security requirements into one cyber security framework with unified implementations, multiple efficiencies are gained. First, the process of assessing the impacts of new regulations or changes to existing regulations is simplified. Second, it standardizes the risk assessment approach and control definitions for new information systems. Third, this approach includes a ready-made self-assessment tool to help identify gaps and develop initiatives to improve overall security. Finally, this approach provides opportunities for leveraging staffing, training, technology, and processes to support multiple regulations and laws.

Figure 31 – SCE's Portfolio Approach to Security Assurance



e) Secure By Design

SCE systems are "secure-by-design," with vendor security requirements provided up-front. Security requirements are based on NIST 800-82 (Guide for Industrial Control Systems), NIST 800-39 (Risk Assessment Methodologies) and NIST 800-53 (Security Controls for Information Systems).

SCE adopts a systems engineering approach that designs security into the Smart Grid, rather than adding it later. The components of this architectural approach are as follows:

- Business drivers define business functions and regulatory requirements;
- Risk assessments identify principal threats and compromises against external and internal threats;
- System security requirements identify the security functions needed to counter or mitigate the threats and risks;
- Security architecture and sub-systems organize the security functions/sub-functions;
- Implementation allows the acquisition, deployment, and configuration of systems with the right quality checks;

- Validation testing and vulnerability assessments ensure that the requirements are built-in; and
- Cyber security requirements are built into vendor contracts.

Security best practices are used for network segmentation, device hardening, intrusion detection systems, intrusion prevention systems, patching, etc. Several projects are underway enabling SCE to test grid applications against the emerging standards and to preview their integration. These include Distribution Management System (DMS) / ALCS, and the EMS hardware/software refresh for AIX/Linus systems.

2. Threat Assessments and Mitigation

For the past several years, extensive vulnerability assessments, penetration tests, and internal scans and tests have been conducted by third parties to evaluate SCE grid security. Organizations leading these assessments include Accuvant (in 2011), Cyphent (in 2010), and Sandia (in 2009).

Later this year, ICF, Inc. will conduct a mock audit in preparation for the live WECC audit, to follow soon after.

a) Conducting Systematic Risk Assessments and Security Audits

SCE's smart grid cyber security program objectives are to Prevent, Detect, Respond, and Recover.

As such, SCE addresses the prevention of, preparation for, protection against, mitigation of, response to, and recovery from security threats for the utility's advanced meter and communications infrastructure, distribution grid management, and distribution grid management with implementation of other smart grid technologies and infrastructure, including all major sub-systems and utility storage of customer information.

SCE uses a "defense-in-depth" strategy to protect grid systems, and utilizes industry standard intrusion detection/prevention (IDS/IPS) systems to detect/prevent network based attacks. Additionally, SCE's Anti-Vulnerability Emergency Response Team (AVERT), a multi-disciplinary security response team from various operational departments, is in place 24/7 to respond to smart grid cyber incidents, including the analysis and mitigation of zero-day attacks.

SCE also regularly conducts systematic risk assessments and security audits based on industry best practices.

b) Annual Improvement Plan

Threat analysis and multiple factors are synthesized to develop SCE's annual improvement program for people, processes, and technology. Periodic threat analysis, annual third party penetration testing, new technology, audit findings, and emerging regulations all influence the development of improvements. As such, the annual security technology program, process improvement plans, and awareness programs are in place to ensure continuous improvement and the implementation of the appropriate risk management measures.

c) Public/Private Partnership

A critical factor in threat analysis is the relationship of electric utilities with the federal/state government. Both the federal government and electric utilities have distinct realms of responsibility and expertise in protecting the bulk power system and standards for threat analysis, both local and global.

The optimal approach to utilizing the considerable knowledge of both government intelligence specialists and electric utilities in ensuring the cyber security of the nation's electric grid is to promote a regime that clearly defines these complementary roles and responsibilities and provides for ongoing consultation and sharing of information between government agencies and utilities.

Fundamentally, the private sector can be disadvantaged in assessing the degree and urgency of possible or perceived cyber threats because of limitations on its access to classified information. The government is entrusted with national security responsibilities and has access to volumes of intelligence to which electric utilities are not privy. Thus the government is able to detect threats, evaluate the likelihood or risk of a malicious attack, and utilize its expertise in law enforcement.

On the other hand, electric utilities are experienced and knowledgeable about how to provide reliable electric service at a reasonable cost to their customers, and understand how complex systems are designed and operated. Owners, users, and operators of the electric grid are in a unique position to understand the consequences of a potential malicious act as well as to propose actions to prevent such exploitation, including preventing unintended consequences of remedial actions. It is critically important to establish a workable structure that enables the government and the private sector to work together in order to provide a more secure system for utility customers.

3. Guidance Documents

a) NIST Documents

SCE plans to incorporate NIST's guidelines through the assimilation of Smart Grid cyber security into the system development life cycle (SDLC), as recommended by the NIST SP800-x series of documents.

NIST IR 7628 guidance/recommendations will be adapted for conducting cyber security risk assessments and determining high level security requirements.

The applicable regulatory security policy requirements from NERC CIP 002 through 009 will be adopted specifying applicable cyber security controls in system design and procurement language, such as those found in NIST SP800-53 rev3; ASAP-SG Security Profiles; and IEC Standards requiring the use of emerging cyber security standards, such as IEC 61850, IEC 62351, IEC 61970, IEC 61968, IEC 60870-6, and IEEE 802.15.4. This includes participating in recovery exercises at the SCE level and at state/national levels to ensure grid resiliency.

b) "Security Profile for Advanced Metering Infrastructure, v 1.0, Advanced Security Acceleration Project – Smart Grid, December 10, 2009

The "Security Profile for Advanced Metering Infrastructure, v 1.0, Advanced Security Acceleration Project – Smart Grid, December 10, 2009," provides guidance and security controls to organizations developing or implementing AMI solutions, including the meter data management system (MDMS), up to and including the HAN interface of the smart meter.

In alignment with this guidance document, SCE co-sponsored/co-developed the ASAP-SG AMI Security Profile, and used the AMI security controls for the SmartConnect (AMI smart meter) implementation. The company also plans to use the completed ASAP-SG Security Profiles for Third Party Data Access and the Distribution Management Security Profile.

SCE will adopt the upcoming ASAP-SG Wide Area Situational Awareness Security Profile, and meanwhile plans to continue supporting development of additional security profiles, specifically the Substation Automation Security Profile and the Home Area Network Security Profile.

c) Catalog of Control Systems Security: Recommendations for Standards Developers, U.S. DHS, National Cyber Security Division, September 2009

The "Catalog of Control Systems Security: Recommendations for Standards Developers, U.S. DHS, National Cyber Security Division, September 2009," presents a compilation of practices that various industry bodies have recommended to increase the security of control systems from both physical and

cyber attacks. SCE will use the DHS security controls indirectly. The DHS security controls have been integrated into and expanded in the ASAP-SG security controls.

d) Cyber Security Procurement Language for Control Systems

DHS developed the "Cyber Security Procurement Language for Control Systems," to provide guidance on the procurement of cyber security technologies for control systems products and services. SCE plans to review the DHS procurement language and incorporate applicable DHS procurement language into smart grid procurement contract documents.

4. AMI Example

Utilities realize that the electric industry itself has numerous shortcomings. These include having no effective mechanism for sharing information on cyber security, even with the proliferation of standards-development bodies, as well as no historical metrics for evaluating cyber security in Smart Grid systems.

Aspects of the regulatory environment may present multiple challenges in ensuring Smart Grid systems cyber security. At present, it is uncertain if the proliferation of emerging industry standards will result in better security features being built into Smart Grid systems.

Adding intelligence to the grid in the face of increasing and evolving threats raises utilities' security concerns. Implementing initial Smart Grid solutions such as AMI in green-field environments creates unique challenges, such as the lack of viable security standards and best practices, product maturity concerns, and vendor maturity concerns.

SCE is overcoming the challenge of building the Smart Grid with emerging, but immature, industry standards and off-the-shelf technology and security solutions. This can be attributed to SCE's focus on comprehensive security, instead of regulatory compliance.

SCE's Advanced Metering Infrastructure (AMI) initiative has progressed with minimum guidance from formal industry standards on smart meter security, as a result of the following:

- SCE collaborated with open consortia and other utilities (utility AMI, Open AMI, etc.) to vet and validate security specifications;
- SCE on-boarded security engineers with Department of Defense and other related experience;
- Sixty security requirements were developed or modified;
- SCE worked with vendors for 18 months to co-develop the appropriate solutions;

- Meter and communication vendors were encouraged to partner with third party specialists in cryptography;
- SCE implemented three types of security validation testing: requirements validation, internal vulnerability assessment, and external penetration testing by third parties;
- Security vulnerabilities were addressed through the process of threat identification, assessment, and mitigation measures; and
- SCE deferred large scale meter deployment until the solutions were ready.

5. Standards Development

SCE leads and supports efforts to accelerate the development of Smart Grid interoperability standards. The company invests in resources in the form of both funds and subject matter experts. SCE also shares architectural and design approaches through professional societies and user groups, such as UCA, UNITE, EnergySec, EPRI, and EEI, while actively participating in a number of standards development initiatives, particularly the NIST Cyber Security Working Group, ASAP-SG, Open SG, IEEE, IEC, OASIS, ZigBee, and Homeplug.

SCE promotes the re-use of cross-cutting, foundational standards, such as leveraging IEC 6198 CIM standards for HAN Enterprise Interface, IDE, and Smart Energy Profile 2.0. The company also supports the harmonization and coordination of various and distinct standards, but there are overlapping standards development efforts which impede rapid adoption.

Another demonstration of SCE's effort to accelerate standards development includes the work the company does with academic and research institutions to develop ideas that will potentially become requirements that will, in turn, feed standards. Furthermore, SCE works with security researchers and leading vendors to develop first product and component-level vulnerability mitigation guidelines.

Public/private partnerships are proving to be critically important in creating a robust and accelerated standards development process.

The process depends on the following key events:

- Identification of stakeholder needs;
- Development of industry standards;
- Vendor-developed standards-based products;
- Ability of independent labs to certify products;
- Utility development of specifications and procurement of certified products; and
- Industry feedback on areas of improvement.

The focus is on creating a self-sustaining market where vendors compete to deliver higher quality products, as well as to increase security and interoperability. This process also needs to be integrated with and driven by the utility procurement process to form a closed loop.

It is important that the federal and state rulemaking processes be closely aligned to standards development to ensure a level of consistency in compliance.

B. Customer Privacy and Data Security

For SCE, these major privacy trends and drivers include more widespread deployment of Smart Grid technology (which will generate and exchange a significant amount of new energy usage and personal customer data), and the growing quantities of data being collected by SCE's business processes.

1. Commitment to maintain customer data security

SCE has policies, controls, and procedures in place to protect customers' Personally Identifiable Information and applicable energy usage data.

SCE developed a set of key principles and requirements, as follows, to guide the development of its Data Protection and Privacy Program:

- Establish clear roles and responsibilities for data ownership and protection requirements;
- Embed data protection and privacy by design into SCE's solution delivery cycle;
- Implement the best available technical and procedural solutions to support the ongoing protection of data;
- Assess SCE's data breach risks and establish effective procedures for its operations;
- Implement a comprehensive data protection and privacy awareness program emphasizing that protection and privacy is everyone's responsibility;
- Define the purpose for which information will be used, collect only data directly relevant and necessary to accomplish a specific purpose, and retain that data only for as long as necessary to fulfill the specific purpose;
- Protect information entrusted to SCE, including information that is shared with third parties; and
- Define and continuously measure success in achieving data privacy protection.

In addition, SCE complies with existing privacy laws, mandates, and standards, up to and including SB 1476 – Chaptered 9/29/2010, Federal Trade Commission Fair Information Practice (FIP) Principles, and the Federal Trade Commission Red Flags Rules to protect against identity theft.

SCE also participates in, or monitors, new and in-process development of industry standards, such as NIST IR 7628 Volume II, Privacy standards for Smart Grid; EEI Smart Grid Interoperability Standards; EEI – North American Energy Standards Board (NAESB) Data Privacy Task Force; Third Party Access to Retail Customer Smart Meter-Based Information; and Dept. of Energy Smart Grid Reports, Data Access and Privacy Issues Related to Smart Grid Technologies.

2. Utilities have a long standing history of maintaining customer data security

The issue of privacy and protection of customer energy data is being addressed by SCE on many fronts. The data breach process has been around for many years (SB 1386), and SCE has been protecting customer data according to industry standards (both cyber security and energy).

SCE's Data Protection and Privacy Strategy covers the data protection strategies for Smart Grid as more data is generated and made available. New types of data, such as real-time usage through the meter and daily summary billing information, will soon be available to customers. While this wide range of usage information will be accessible through the web, customer access to data is controlled through authentication, authorization, and audit mechanisms.

Third party access to data, such as daily summary billing information, is also controlled. Access is granted (such as through the meter) at the customer's discretion and following explicit approval. Standards being developed by NAESB on third party access to energy data are being tracked as emerging privacy standards continue to be developed.

3. SCE security practices are evolving and dependent on privacy practices

New security policies will be developed, and existing policies modified, to address emerging personal privacy issues. Privacy protection measures are designed into Smart Grid solutions and standards as part of the solutions delivery cycle. Privacy impact assessments (PIAs) are conducted prior to deploying Smart Grid technologies. SCE will continue to develop and deploy personal privacy training and awareness programs.

In the future, privacy use cases will be developed to address risks in business processes, and customers will be educated about Smart Grid privacy risks and how to mitigate them.

4. Responses to Cyber Security Questions

a) What types of information about customers are or will be collected via the smart meters, and what are the purposes of the information collection? Could the information collection be minimized without failing to meet the specified purposes?

SCE's smart meters collect the information listed in Table 7 on the next page. This table identifies the attributes and the purpose of the information collection:

Table 7 – Data Collected by SCE's Smart Meters

Attribute	Description	Purpose
Usage	SCE's smart meters collect interval usage (hourly for residential customers and 15-minute intervals for non-residential) reflecting the amount of energy a customer used in a given time period.	Usage information is collected to enable SCE to bill its customers. Usage data may also be used to derive a customer's demand, which is used for customer billing and customer rate eligibility.
Voltage	Smart metering infrastructure collects events surrounding voltage. The events provide information on power interruptions, over/under voltage alarms, and the quality of service delivered.	SCE is not utilizing voltage monitoring at this time. However in the future SCE plans to monitor the following: - Low Voltage Threshold - High Voltage Threshold - Low Instantaneous Voltage Threshold - High Instantaneous Voltage
kVar	kVar is used to measure reactive power for high usage customers.	SCE uses kVar for high usage customers.
Meter configuration changes	Smart metering infrastructure supports both optical and over the air meter configuration changes. In addition to meter configuration flagging which notifies upstream systems of a configuration mismatch.	SCE meter configurations are managed upstream and validated upstream. SCE systems manage, validate, and resolve configuration conflicts in the following situations: - Deployment: Validates and manages configuration changes without field visits. - Move in/Move out: Premise changes that affect rate - Rate Changes: Customer joining DR, CPP, or TOU plans.
Meter power outages	Smart metering infrastructure supports the aggregation of power outage notification (PON) exceptions upstream with timestamp. The system also supports the aggregation of power restoration notification (PRN) exceptions with timestamp. Exceptions are messages that are pushed upstream either as a broadcast or as a targeted message.	- SCE collects PON messages to determine if an area is encountering a power outage. - SCE collects PRN messages to determine if an area is recovering from a power outage.
Meter service switch operations	Smart metering infrastructure supports connect/disconnect both over the air and optically. The meter configuration controls whether this feature is enabled or not.	SCE utilizes the meter's service switch for both move out and credit-related disconnect. The system is capable of supporting this function OTA but it is currently supported only for Optical use.
HAN device registrations	Smart metering infrastructure supports over the air and optical secure HAN device registrations based on the SEP 1.0 standard at this time. The meter stores device registrations	SCE currently supports the optical use of HAN device registration with a goal to increase scope to OTA HAN device registration.

The information collected is the minimal amount of information necessary to enable SCE to accurately bill customers and to provide quality customer service and reliability. The information collected cannot be reduced without impacting the ability of SCE to fulfill the specified purposes.

b) Does the utility have or expect to have other types of devices, such as programmable communicating thermostats, which can collect information about customers? If so, what types of information is collected, and what are the purposes of the information collection? Could the information collection be minimized without interfering with the specified purposes?

SCE assumes the term "device" in this question refers to HAN devices. SCE expects that its customers will use devices, such as PCTs, that may collect customer information, including energy usage. However, SCE does not plan to provide these devices and expects that they will generally be available in the marketplace. Because the devices are not SCE devices, SCE will not collect any customer information from the devices.

SCE does expect to collect customer usage information necessary to support certain programs or services from HAN-connected meters. For example, SCE may collect usage information from a HAN-connected meter designated for a PEV.

c) What types of information, if any, does the utility plan to collect from the smart meter and HAN gateway?

Device registration is necessary to enable customers to receive near real-time energy information, participate in DR programs, and receive or respond to DR signals from the meter. Basic device registration or pairing ensures that a secure wireless connection exists between the customer's smart meter and the HAN device so that the device receives the intended information or signal. From this wireless "gateway," SCE plans to collect information consistent with facilitating programs and normal HAN operation. This information may include: network performance data, acknowledgements received from HAN devices, and information to facilitate customer troubleshooting.

Information collected through the gateway from customer-owned HAN devices registered with SCE will be device-specific and consistent with program or service operations. For example, SCE may request a device's capabilities via a Smart Energy Profile (SEP) command in order to determine which form of load control a PCT supports (e.g., duty cycle, temperature offset). This would typically occur during program enrollment and registration. SCE will also collect device acknowledgements of certain commands as specified in SEP. For example, if a customer is enrolled in a DR program and SCE sends a DR signal through the gateway, SCE may request an acknowledgement from the customer's PCT that it received the event. If a customer were to override the DR action taken by the PCT, the PCT may communicate the

override to SCE via the gateway. This facilitates SCE's operational need to estimate the aggregate DR performance realized during a DR event.

d) How frequently will the utility take readings from the smart meter? Is this frequency subject to change? Will customers control this frequency?

For the majority of SCE's smart meters, SCE retrieves meter reads from the smart meter once per day. Additionally, SCE retrieves network management information and statistics (e.g. received signal strength indicator and radio frequency local area network levels) once per day. For those commercial customers whose meter utilizes multiple channels, SCE retrieves reads every 12 hours. The frequency at which SCE takes readings from its smart meters may be subject to change, however, SCE has no current plans to change this frequency. Customers do not control the frequency with which SCE takes readings from its smart meters.

e) For each type of information identified above, for what purposes will the information be used? The purposes should be articulated with specificity, e.g., "targeted marketing" instead of "promoting energy efficiency."

SCE's responses to questions 1, 2, and 3 identify both the type of information collected and the purpose for collecting the information. Please refer to those responses for specific purposes. Generally, all information collected by SCE from smart meters, the HAN, or the HAN/meter gateway will be consistent with program eligibility or operation requirements.

f) For each type of information collected, for how long will the information be retained, and what is the purpose of the retention? Could the retention period be shortened without diminishing the specified purpose?

Table 8 includes the retention period and purpose of retention for the data collected in the meter. The retention period cannot be shortened without diminishing SCE's ability to provide high-quality customer service.

Table 8 – SCE Meter Data Retention Periods

Attribute	Retention Period	Retention Purpose
Usage	60 Months	Billing
Voltage	60 Months	Customer service
kVar	60 Months	Billing
Meter configuration changes	60 Months	Billing
Meter power outages	60 Months	Customer Service
Meter service switch operations	60 Months	Customer service
HAN device registrations	39 Months	Customer service

For data from the HAN and HAN/meter gateway, SCE is planning to store at least 5 years of data. Information such as the frequency of HAN communication failures and number of customer overrides per DR event will factor into an algorithm used to forecast the MW reduction for each DR program. Though it currently does not plan to do so, SCE may decide to increase the duration of data retention in the future in an effort to improve the accuracy of the load drop estimation. In addition to being useful for the MW reduction forecast, a five-year HAN data retention period is adequate to support the HAN device troubleshooting process, SCE/regulatory reporting needs, and other program management requirements. The retention period cannot be shortened without diminishing these activities.

g) What measures are or will be employed by the utility to protect the security of customer information?

For the SmartConnect deployment, SCE has deployed military grade security across the AMI solution and similarly, strong security measures have been developed for the HAN functionality. Additionally, SCE operates its own AMI network so the data is not exposed to an outsourced AMI operation company. SCE's policies and procedures in the handling and disclosure of customer data are well defined and governed by controls to secure written authorization from the customer prior to disclosure of data to a third party. Furthermore, SCE is engaged in the development of the Energy Service Provider Interface standard at NAESB and has helped design strong electronic authorization to ensure only data explicitly authorized for disclosure to a specific third party is released.

h) Has the utility audited or will it audit its security and privacy practices, both internally and by independent outside entities? If so, how often will there be audits? What are the audit results to date, if any?

SCE has conducted annual internal audits on its SmartConnect implementation for the past four years. To date, there have been no SmartConnect audits conducted by third parties or independent outside entities. While the audits did not specifically focus on privacy, the data security reviews evaluated the protection and, by extension, the privacy, of customer and energy information on these systems.

In 2008, a review of the technology controls in the implementation of SmartConnect was conducted by internal audits, focusing on the design and implementation of the network and supporting components. The processes around the overall design were found to be adequate.

In 2009, a risk assessment of the technology supporting the SmartConnect program and deployment implementation was conducted to determine if effective controls to mitigate inherent technical risks have been designed and documented. The general findings were limited due to a compressed project testing schedule; however, additional time was granted to mitigate vendor product vulnerabilities.

In 2010, the audits focused on technology controls, particularly handling network-based threats, network incident and intrusion detection/response, data and processing capacity, and interface security dealing with data completeness and billing accuracy. Some deficiencies were identified resulting in the development of detailed responses and action plans.

In 2011, the SmartConnect information technology over the Meter Data Management System (MDMS) assessed the effectiveness of controls in place to mitigate inherent risks associated with this new and evolving advanced metering technology. Operational effectiveness was identified in the areas of user account and password management, application access, network and processing controls, system performance and capacity management, patch management, and business data resiliency. Some control procedure weaknesses were identified and are being addressed. The audits concluded that the overall effectiveness of these controls is a strong and positive indication that the SmartConnect controls and processes are effective.

IX. Metrics

The metrics presented in this section represent a first step in quantitatively assessing the present status of the electric grid as well as measuring progress in implementing smart grid-related policy goals in California, namely those enumerated in SB 17 and Public Utilities Code § 8360. These metrics will furthermore provide the Commission with information to assist in the production of an annual report to the Legislature, as required under Public Utilities Code Section 8367. In the absence of a decision which adopts finalized metrics for inclusion in this deployment plan, SCE here reports on the consensus metrics proposed in the California IOUs' *Report on Consensus and Non-Consensus Smart Grid Metrics* submitted on October 22, 2010. These consensus metrics were developed in consultation with EDF and are the result of over a year's worth of discourse and deliberation entailing workshops, stakeholder comments, and public "webinars" facilitated by Commission staff. Furthermore, these metrics leverage information from other reporting requirements, including those related to DR and reliability, in an effort to reduce the burden of implementation as directed in D.10-06-047.[154] All metrics data provided in this section is reported as of December 31st 2010.

A. Customer / AMI Metrics

1. Number of advanced meter malfunctions where customer electric service is disrupted

Metric - Meter Malfunctions	Total
Number of Advanced Meter Malfunctions Interrupting Customer Service	0

A SmartConnect meter failure resulting in a disruption of customer electric service would occur if there was a malfunction in the integrated service switch. As of December 31, 2010, there were no instances of an integrated service switch malfunction. This metric as described in the Report on Consensus Metrics includes only advanced meter malfunctions that result in loss of power, which may be insignificant and not relevant to overall effectiveness of smart meter performance for purposes of energy and outage management, especially following completion of deployment. Furthermore, this metric does not include malfunctions that do not result in service disruptions (e.g., usage measurement malfunctions).

154 D. 10-06-047, p 85.

2. Load impact from smart grid-enabled, utility administered DR programs (in total and by customer class, to the extent available)

Metric - Smart Grid Enabled DR	Customer Class	Load Impact (MW)
Load impact from smart-grid enabled, utility administered demand response programs	Residential	NA
	C&I < 200 kW	NA
	C&I > 200 kW	NA
	Ag & Pumping	NA
	Total	NA

As of December 31, 2010, SCE has installed 2,022,221 SmartConnect meters. Participation in SmartConnect-enabled programs requires a program-ready SmartConnect meter (i.e., customer billed based on collected interval usage data). SCE began billing customers on interval usage data in late-2010 and program enrollments in available SmartConnect-enabled programs are expected to begin in 2011. Thus, there were no program enrollments in 2010.

Note that in 2010, SCE administered Critical Peak Pricing, Demand Bidding Program, and Capacity Bidding Program for large C&I customers (>200 kW) that resulted in a load impact of 108.9 MW. These programs utilize legacy interval meters and customers may view their interval usage data through SCE's EnergyManager programs. However, the legacy interval meters do not support HAN or event notifications, therefore these programs are excluded from this metric.

3. Percentage of demand response enabled by AutoDR (Automated DR) by individual DR impact program

Metric - % Auto DR	Price Responsive Program	% Auto DR
Percentage of demand response enabled by AutoDR by individual DR impact program	CBP	2%
	CPP	10%
	DBP	23%

In 2010, SCE's demand response programs with AutoDR capabilities included the Capacity Bidding Program, Critical Peak Pricing, and the Demand Bidding Program. AutoDR load reductions from these programs were approximately 19 MW in 2010.

4. The number of utility-owned advanced meters with consumer devices with Home Area Network (HAN) or comparable consumer energy monitoring or measurement devices registered with the utility (by customer class, CARE, and climate zone, to extent available)

Metric - HAN Registered Devices	Total
The number of utility-owned advanced meters with consumer devices with Home Area Network (HAN) or comparable consumer energy monitoring or measurement devices registered with the utility (by customer class, CARE, and climate zone, to extent available)	0

Consumer device capabilities have been postponed due to a delay in the adoption of the Smart Energy Profile 2.0 HAN national standard and uncertainty regarding commercial availability beyond that date. Currently, the IOUs expect this capability may become available in the 2014 timeframe. Thus, this metric will be relevant and reported as part of future Smart Grid Annual Reports.

However, SCE launched a field trial in 2010 with 36 SmartConnect customers. SCE utilized SEP 1.0 devices in order to develop SCE's understanding of future HAN operational needs. SCE expects full scale deployment of SEP 2.0 HAN technologies in 2014. Of the 36 customers participating in the field trial, 14 were CARE customers. In addition, SCE is planning to commence a pilot in the fourth quarter of 2011 with up to several thousand customers. The pilot will be focused on, among other things, providing customers with near real-time usage data through HAN devices registered with SmartConnect meters through SCE's back office systems, and obtaining customer feedback on HAN devices, enrollment processes, and behavioral changes resulting from information received through the HAN.

In future reports, this metric will only include devices that are registered with the utility's HAN. Devices that connected with a different gateway are excluded. Also, devices that are connected to an energy management system, but not registered with the utility, are excluded (even though the energy management system may be registered with the utility). SCE does not currently have the capability to track devices by CARE/non-CARE and climate zone. SCE would need to add this functionality to its data warehouse system in order to provide this data.

5. Number of customers that are on a time-variant or dynamic pricing tariff (by customer class, CARE, and climate zone, to the extent available)

Metric - TOU and Dynamic Pricing Tariffs	Customer Class	Total Customers
Number of customers that are on a time-variant or dynamic pricing tariff (by customer class, CARE, and climate zone, to the extent available)	Residential	0
	C&I < 200 kW	0
	Ag & Pumping	0
	Total	0

This metric includes those customers who are on a time variant or dynamic pricing tariff and whose usage was being measured by a program-ready SmartConnect meter (i.e., customer billed based on collected interval usage data) as of 12/31/2010. SCE began billing customers on interval usage data in late-2010 and program enrollments in available SmartConnect-enabled programs and rates are expected to begin in 2011. Thus, there were no customers on a time-variant or dynamic pricing tariff with a program-ready SmartConnect meter in 2010.

6. Number of escalated customer complaints related to (1) the accuracy, functioning, or installation of advanced meters or (2) or the functioning of a utility-administered Home Area Network with registered consumer devices

Metric - Customer Complaints	Complaint Type	Total
Number of escalated customer complaints related to (1) the accuracy, functioning, or installation of advanced meters or (2) or the functioning of a utility-administered Home Area Network with registered consumer devices	Meter Accuracy	84
	Meter Installation	30
	Meter Functioning	48
	HAN	0

For SCE, these are complaints received by SCE's Consumer Affairs department. SCE has defined the customer complaints as follows:

Meter Accuracy – Escalated complaints to SCE's Consumer Affairs department related to high bills.

Meter Installation – Escalated complaints to SCE's Consumer Affairs department regarding SCE's SmartConnect installation contractor (e.g., damaged property during meter installation).

Meter Functioning – Escalated complaints to SCE's Consumer Affairs department regarding issues such as radiofrequency/electromagnetic frequency, net energy metering reconciliation, and customer deployment opt-out requests.

Upon the widespread availability of HAN devices to customers, this metric will include all escalated complaints related to consumer devices, including those complaints that were determined to be caused by the consumer device and not the utility HAN.

7. Number of utility-owned advanced meters replaced annually before the end of their expected useful life

Metric - Meter Replacement	Total
Number of utility-owned advanced meters replaced annually before the end of their expected useful life.	8,535

This metric includes the number of SmartConnect meters that were replaced during the 12 months ending December 31, 2010, which represents a meter failure rate less than SCE's SmartConnect business case assumption, as approved in D.08-09-039.

8. Number of advanced meter field tests performed at the request of customers pursuant to utility tariffs providing for such field tests

Metric - Meter Field Tests	Total
Number of advanced meter field tests performed at the request of customers pursuant to utility tariffs providing for such field tests	604

This metric includes the number of field tests performed by SCE personnel on SmartConnect meters at the customer's request pursuant to SCE's tariffs as of December 31, 2010.

9. Number and percentage of customers with advanced meters using a utility administered internet or web-based portal to access energy usage information or to enroll in utility energy information programs

Metric - Usage Info	Total	Percentage
Number and percentage of customers with advanced meters using a utility-administered internet or web-based portal to access energy usage information or to enroll in utility energy information programs	0	0

Customers with a program-ready SmartConnect meter may begin to register in SCE's web-portal to view their interval usage data in 2011. Thus, there were no customers utilizing a utility administered internet or web-based portal to access energy usage information or to enroll in utility energy information programs as of December 31, 2010.

In future reports, this metric will measure unique customers using web-based tools and other energy information programs available that will not require customers to access the Web. Examples of these programs include Tier Alert (PG&E and SDG&E) and Budget Assistant (SCE) programs. This metric excludes customers accessing usage information through non-utility portals, and also excludes customers accessing cumulative usage information. This metric was expanded to include customers enrolling in energy management programs to better capture the penetration of customers accessing their energy information in manners other than the utility portals.

B. PEV Metrics

1. Number of customers enrolled in time-variant electric vehicles tariffs

SCE currently supports a total of four time-variant electric vehicle tariffs with the following enrollment numbers:

Metric - PEV Tariff Enrollment	Residential		Commercial	
Number of customers enrolled in time-variant electric vehicles tariffs	TOU-D-TEV	25	TOU-EV-3	14
	TOU-EV-1	57	TOU-EV-4	21

Time variant rates are a crucial part of managing PEV load and integrating PEVs onto the grid. However, over time as more market data becomes available, additional rate studies are performed, and new technologies evolve, SCE expects to offer enhanced versions of its current EV rate offerings. Also, it should be recognized that there are many factors influencing a customer's decision to adopt a PEV rate. In many cases, a PEV customer charging at 1.4 kW (and appearing as any other normal appliance) in a coastal zone will not have a financial incentive to switch from his or her tiered rate. In fact, SCE expects that most Plug-in Hybrid Vehicles will not switch to EV rates given smaller battery sizes and lower charging levels. As an example, in June of 2011, after 6 months of early market EV sales (with targeted marketing to those customers) 35 percent of residential customers owning an EV are currently opting for an EV-specific tariff.

TOU-EV-3 and TOU-EV-4 are only available to commercial customers. It should be noted that the reported value for this metric represents customer accounts which often charge many vehicles on a single dedicated meter (i.e., golf carts, electric trucking fleets, and electric forklifts). TOU-EV-4 is only available to customers above 20 kW and incorporates a demand charge while TOU-EV-3 does not.

C. Storage Metrics

1. MW and MWh of grid connected energy storage interconnected at the transmission or distribution system level

Metric - Energy Storage	# of Facilities	Total MWs	Total MWhs/yr
MW and MWh of grid connected energy storage interconnected to utility facilities at the transmission or distribution system level	1	207 MWs	500 MWhs/yr

As of December 31, 2010, SCE's Eastwood power station – a pumped storage hydro facility located within the broader Big Creek complex – represents the only energy storage facility interconnected to either SCE's transmission or distribution system. This pumped storage hydro facility has a capacity of approximately 207 MWs and produces roughly 500 MWh per year.[155]

155 The annual energy production of SCE's pumped hydro facility varies from year to year depending on hydrological reserves and resource dispatch requirements.

D. Grid Operations Metrics

1. The system-wide total number of minutes per year of sustained outage per customer served as reflected by the System Average Interruption Duration Index (SAIDI), Major Events Included and Excluded

Metric - SAIDI	Year	Major Events Included	Major Events Excluded
The system-wide total number of minutes per year of sustained outage per customer served as reflected by the System Average Interruption Duration Index (SAIDI), Major Events Included and Excluded	2001	60	45.71
	2002	52.29	44.95
	2003	89.26	53.37
	2004	74.93	55.3
	2005	92.26	72.57
	2006	142.14	96.59
	2007	151.32	85.34
	2008	118.91	99.35
	2009	105.8	88.77
	2010	140.91	98.69

As indicated in the 2010 Annual System Reliability Report, the SAIDI metrics data provided here utilizes a definition of "sustained" interruption as described in IEEE Standard 1366, 2003 Edition, which is an interruption lasting longer than 5 minutes. SCE intends to file, in the near future, an advice letter informing the Commission of its intent and schedule for fully transitioning from the calculation methods of D. 96-09-045 to those of IEEE 1366.

2. How often the system-wide average customer was interrupted in the reporting year as reflected by the System Average Interruption Frequency Index (SAIFI), Major Events Included and Excluded

Metric - SAIFI	Year	Major Events Included	Major Events Excluded
How often the system-wide average customer was interrupted in the reporting year as reflected by the System Average Interruption Frequency Index (SAIFI), Major Events Included and Excluded	2001	1.19	0.97
	2002	1.27	1.05
	2003	1.39	1.11
	2004	1.34	1.15
	2005	1.53	1.33
	2006	1.05	0.89
	2007	1.1	0.88
	2008	1.06	0.95
	2009	0.9	0.83
	2010	1.05	0.82

As indicated in the 2010 Annual System Reliability Report, the SAIFI metrics data provided here utilizes a definition of "sustained" interruption as described in IEEE Standard 1366, 2003 Edition, which is an interruption lasting longer than 5 minutes. SCE intends to file, in the near future, an advice letter informing the Commission of its intent and schedule for fully transitioning from the calculation methods of D. 96-09-045 to those of IEEE 1366.

3. The number of momentary outages per customer system-wide per year as reflected by the Momentary Average Interruption Frequency Index (MAIFI), Major Events Included and Excluded

Metric - MAIFI	Year	Major Events Included	Major Events Excluded
The number of momentary outages per customer system-wide per year as reflected by the Momentary Average Interruption Frequency Index (MAIFI), Major Events Included and Excluded	2001	1.16	1.08
	2002	1.15	1.09
	2003	1.43	1.15
	2004	1.21	1.05
	2005	1.47	1.23
	2006	1.85	1.52
	2007	1.74	1.37
	2008	1.73	1.56
	2009	1.45	1.31
	2010	1.69	1.41

As indicated in the 2010 Annual System Reliability Report, the MAIFI metrics data provided here utilizes a definition of "sustained" interruption as described in IEEE Standard 1366, 2003 Edition, which is an interruption lasting longer than 5 minutes. SCE intends to file, in the near future, an advice letter informing the Commission of its intent and schedule for fully transitioning from the calculation methods of D.96-09-045 to those of IEEE 1366.

4. Number of customers per year and circuits per year experiencing greater than 12 sustained outages

Metric - Greater than 12 Outages	Year	Customers/yr	Circuits/yr
Number of customers per year and circuits per year experiencing greater than 12 sustained outages	2001	2605	9
	2002	1896	4
	2003	7212	19
	2004	12269	26
	2005	3123	13
	2006	93	2
	2007	741	3
	2008	1473	16
	2009	435	8
	2010	167	5

The number of customers and circuits per year experiencing greater than 12 sustained outages can be attributed to a number of natural and man-made causes. In 2010, eight out of the ten longest sustained outages were caused by contact with vegetation, wind, lightning, or fire. Only two of the ten longest outages were caused by overloaded circuit conditions created when customer demand for electricity exceeds the carrying capacity of T&D equipment or infrastructure.

5. System load factor and load factor by customer class

Metric - Load Factor	Customer Class	2010 Load Factor
System load factor and load factor by customer class	Residential	36%
	C&I < 200 kW	48%
	C&I > 200 kW	65%
	Ag & Pumping	62%
	System	53%

Load factor is defined as the average load throughout a given year divided by the peak load during that same year. This value can be calculated for an entire system or a specific customer class and is typically used as a measure of how effectively generation capacity is used. SCE calculates system load factor and load factor by customer class every year as part of its annual rate group load studies, which are leveraged for analyses in the Phase II (Rate Design) of the GRC. This process leverages statistically valid load data from over 5,000 customers, representing all classes of Edison customers, with each sampled customer exceeding 35,000 data points[156]. Since 1982, system load factor has stayed within 51.90 percent and 59.54 percent indicating ample opportunity to reduce peak demand and associated costs for customers. Load factors by customer class often reside outside of this system wide range because of their differing load profiles, or energy consumption patterns.

6. Number of and total nameplate capacity of customer-owned or operated, grid-connected DG facilities

Metric - DG Number & Capacity	Program	# of Facilities	Capacity (MW)
Number of and total nameplate capacity of customer-owned or operated, utility grid-connected distributed generation facilities	CREST (FIT)	2	1.8
	RAM (FIT)	0	0
	SPVP	2	3
	CSI	18730	206.8
	SGIP		
	Total	18,734.00	211.6

156 *See* http://asset.sce.com/Regulatory/SCE percent20Load percent20Profiles/hist_met.pdf for details on the methodology used for SCE's annual rate group load studies.

SCE offers two state-mandated incentive programs (SGIP and CSI) for customer side of the meter DG, also called "onsite generation" or "self-generation". SGIP represents the single largest and longest running DG incentive programs in the country providing one-time, up-front incentives for qualified distributed energy resources installed on the customer's side of the meter. Qualifying technologies currently include wind turbines, fuel cells, and energy storage units (coupled with renewable power systems). Prior to 2008, the program also provided incentives for photovoltaics, micro turbines, and distributed internal combustion engines. SGIP-funded DG facilities installed in SCE's service territory represent approximately 19 percent of the program total in 2009.[157]

CSI is by far the largest contributor to both the total number and capacity of customer-owned or operated DG facilities in SCE's service territory. Since it launched in 2007, the CSI program has provided a combination of up-front, capacity-based incentives ($/Watt) for residential customers and performance based incentives ($/KWh) typically for large commercial, government and non-profit customers. The CSI program is supplemented by other renewable electricity components—namely the Single-family and Multi-family Affordable Solar Housing programs (SASH and MASH)—and is expected to provide a total of 1,940 MW of state-wide solar capacity by 2017.

SCE also supports programs and policies related to procurement of utility-side of the meter DG, also called "wholesale" or "system-side generation" because it is intended to net export onto the electrical system on the other side of the customer meter or connect to the distribution system directly. SCE offers a renewable feed-in tariff under the CREST program which executes a power purchase agreement where SCE will pay for either the total or excess energy a customer generates through facilities less than 1.5 MW. This program accommodates practically all renewable technologies up to a total of 247.690 MW, which is SCE's share of the 500 MW state cap. SCE's Solar PV Program allows SCE, over a five year period, to build and operate 250 MWs of utility-owned solar photovoltaic capacity and to execute contracts up to 250 MW for generation from similar facilities owned and maintained by IPPs through a competitive solicitation process. This program is applicable to primarily rooftop solar PV facilities with a small portion of ground mounted facilities. As of December 31st 2010, SCE owned and operated 2 DG facilities[158],[159] under the Solar Photovoltaic Program and filed for approval 29 PPAs which had not yet been brought online. Finally, SCE now offers a Renewable Auction Mechanism (RAM) which is a simplified and market-based procurement mechanism for renewable DG projects up to 20 MW on the system side of the meter. This program was

157 CPUC, Self-Generation Incentive Program Ninth-Year Impact Evaluation (June 2010).

158 SPVP brought on-line 7 additional projects in the last days of 2010, which were generating test power, however were not yet fully completed. These projects are not included on this list.

159 SPVP projects fit the definition of "DG Facilities" because they are part of the utility's own Solar PV program, however it should be noted that they are not "customer-owned or operated" as indicated in the *Report on Consensus and Non-Consensus Smart Grid Metrics* submitted by SCE, Pacific Gas and Electric Company and San Diego Gas & Electric Company, in consultation with Environmental Defense Fund.

recently implemented in 2011 and does not yet have any interconnected facilities; however, SCE is allowed to procure up to 498.4 MWs in the first two years of the program.

7. Total annual electricity deliveries from customer-owned or operated, grid-connected DG facilities

Metric - DG Electric Deliveries	Program	Total kWhs
Total annual electricity deliveries from customer-owned or operated, utility grid-connected distributed generation facilities	CREST (FIT)	7,880,161
	RAM (FIT)	0
	SPVP (FIT)	4,447,272
	NSC	0
	Total	12,327,433

Facilities brought online under SCE's CREST and SPVP programs together produced over 12 million kWh in 2010 alone. This value captures only electric deliveries to the grid; it does not represent the total energy production of distributed generators in SCE's territory. All of the energy provided by distributed generators in either the CSI or SGIP program is "customer side of the meter", meaning that it first serves customer load before feeding any excess energy onto the distribution system. As of January 1st 2011, SCE has offered a net surplus compensation (NSC) rate to be paid to NEM customers who produce more kilowatt hours than they consume in a 12-month period. Because this rate was not offered in 2010, the reported metric value is zero. This metric will be updated to reflect electric deliveries provided by CSI and SGIP customers as well as any other customers on NEM. RAM was also implemented in 2011 and as such did not provide any electric deliveries to the grid within the timeframe of this metric.

8. Number and percentage of distribution circuits equipped with automation or control equipment, including Supervisory Control and Data Acquisition (SCADA) systems

Metric - Circuit Automation	# of Automated Circuits	Total Circuits	% Automated
Number and percentage of distribution circuits equipped with automation or control equipment, including Supervisory Control and Data Acquisition (SCADA) systems	2,079	4,459	46.60%

As of December 31, 2010, SCE had a total of 4,459 distribution circuits in operation—2,079 of which are automated with mid and/or tie remote control switches. This metric indicates that just over 46 percent of circuits can be remotely monitored and controlled through SCE's existing DMS system to protect critical distribution equipment, restore outages, and minimize customer minutes interrupted.

X. Appendix A – Baseline Privacy Practices

1. What data is the utility now collecting?

See Section VIII.B.4.a). However, on December 31, 2010, SCE was only collecting Usage and Meter Configuration changes.

2. For what purpose is the data being collected?

See Section VIII.B.4.a).

3. With whom will the utility currently share the data?

Please see SCE's response to question #7 below.

4. How long will the utility currently keep the data?

See Section VIII.B.4.f).

5. What confidence does the utility have that the data will is accurate and reliable enough for the purposes for which the data will be used?

SCE is highly confident that the data it collects in the SmartConnect meter are accurate and reliable and serve the purposes for which they are collected. SCE's SmartConnect meters go through extensive testing and certification. SCE has a rigorous Meter Quality Program (MQP) that adheres to the Direct Access Standards for Metering and Metering Data (DASMMD). DASMMD specifies the minimum standards for safety, accuracy, and reliability of: meter equipment; meter communications; meter data management and meter reading; and meter installation, testing, and calibration. SCE's MQP also abides by Tariff Rule 17 and follows ANSI Standards as required by DASMMD.

As part of its MQP, SCE requires meter vendors to test 100 percent of meters shipped to SCE and to provide their test results. Factory meter tests are conducted with equipment certified by the National Institute of Standards and Technology (NIST). SCE also conducts quality audits at its vendor's factories. All new meter products procured by SCE undergo quality control testing to ensure the products meet

SCE's quality requirements. Once meters are deployed to the field, SCE follows a field meter test and maintenance schedule required by DASMMD to assure that SCE's meter population is accurate as long as the meters are in service.

6. How does the utility protect the data against loss or misuse?

See Section VIII.B.4.g).

7. With whom does the utility share customer information and energy data currently? With whom does the utility reasonable foresee sharing data in the future? What does the utility anticipate is or will be the purpose for which the third party will use the data? What measures are or will be employed by the utility to protect the security and privacy of information shared with other entities? What limitations and restrictions will the utility place on third-part use and retention of data and on downstream sharing? How will the utility enforce those limitations and restrictions?

As of December 31, 2010, SCE did not share any data collected from its smart meters with any third parties. In the future, SCE expects to share customer usage data with SCE's contracted vendors for EE and DR. SCE will also share customer usage data, when authorized to do so by the customer, with third parties. The reason for providing data to a third party will ultimately be between the customer and the third party, though SCE anticipates that third parties will generally use the data to help customers better understand their energy usage and to offer energy management solutions. To protect the security and privacy of information shared with other entities, SCE will follow all applicable laws and regulations, including any applicable requirements in the Commission's Decision Adopting Rules to Protect the Privacy and Security of the Electricity Usage Data of the Customers of Pacific Gas & Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company when it becomes final. Similarly, any limitations and restrictions SCE places on third party use and retention of data will be guided by applicable laws and regulations.

8. How do individuals have access to the data about themselves?

As of December 31, 2010, customers were not yet able to view their interval usage data online. However, beginning in 2011, customers with operational smart meters were able to view their interval usage on SCE.com.

9. What audit, oversight and enforcement mechanisms does the utility have in place to ensure that the utility is following its own rules?

See Sections VIII.B.4.g) and VIII.B.4.h).

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 APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) FOR APPROVAL OF ITS SMART GRID DEPLOYMENT PLAN 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 **1st day of July, 2011**, at Rosemead, California.

/s/ NORMA PEREZ

Norma Perez
Project Analyst
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770

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