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SOUTHERN CALIFORNIA EDISON

Smart Grid Annual Deployment Plan Update

October 1, 2017

Smart Grid Deployment Plan Annual Report

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I. Executive Summary

California's landmark Smart Grid legislation, Senate Bill (SB) 17, established that "[i]t is the policy of the state to modernize the state'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" various goals aimed at a cleaner energy future, energy efficiency, and more engaged customers.[1] SB 17 mandated that electric utilities submit smart grid deployment plans to the California Public Utilities Commission (CPUC or Commission) for approval. Southern California Edison Company (SCE) submitted its Smart Grid Deployment Plan on July 1, 2011.[2] The Commission ruled on these plans during their July 25, 2013 business meeting, voting unanimously to approve the plans submitted by the electric utilities.[3]

Also, SB 17 required the Commission provide an annual report to the Governor and the Legislature "on the commission's recommendations for a smart grid, the plans and deployment of smart grid technologies by the state's electrical corporations, and the costs and benefits to ratepayers."[4] In turn, the Commission ordered the California investor-owned electric utilities (IOUs) to provide an annual update on the status of their Smart Grid investments.[5] In the annual update reports, SCE explains the following: (1) deployment of Smart Grid technologies; (2) progress toward meeting the utility's Smart Grid Deployment Plan; (3) the costs and benefits to ratepayers, where such assessments were feasible; (4) current deployment and investment initiatives; (5) updates to security risk and privacy threat assessments; and (6) compliance with security rules, guidelines, and standards.[6] On August 2, 2013, the Commission issued D.13-07-024 adopting the report template and format used by the IOUs for their annual updates reporting on the progress of its smart grid projects and initiatives.

On December 4, 2014, the Commission issued D.14-12-004 closing the Smart Grid proceeding, formally known as the *Rulemaking to Consider Smart Grid Technologies Pursuant to Federal Legislation and on the Commission's own Motion to Actively Guide Policy in California's Development of a Smart Grid System.*[7]

In this latest annual report, the 6th update to the Smart Grid Deployment Plan, SCE provides an update to cover the most recent reporting period of July 1, 2016 through June 30, 2017 (Reporting Period). Through this Smart Grid Deployment Plan Update, SCE complies with its reporting obligation and assists the Commission in developing the Commission's own annual report to the Governor and the Legislature.

In the Smart Grid Deployment Plan, SCE described its deployment baseline and its vision for the Smart Grid. This Update details SCE's progress on specific projects. There are six types of projects:

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1 Pub. Util. Code § 8360.
2 *See* Application (A.) 11-07-001.
3 Decision (D.) 13-07-024.
4 PUB. UTIL. CODE § 8367.
5 Decision (D.)10-06-047, Ordering Paragraph 15.
6 *Id.*
7 R.08-12-009.

1. Customer Empowerment;
2. Distribution Automation/Reliability;
3. Transmission Automation/Reliability;
4. Asset Management & Operation Efficiency;
5. Security; and
6. Integrated & Cross-Cutting Systems.

SCE's **Customer Empowerment** efforts provide customers with information regarding their energy usage, as well as programs, rates, and technologies to enable energy conservation and peak load reductions. This energy information (e.g., interval usage data, near real-time usage, cost information and event notifications) will better facilitate customers' ability to participate in time-variant rates. These customer-oriented efforts will also provide information accessible in a variety of ways (e.g., web and mobile devices) to customers and authorized third-party service providers.

Distribution Automation/Reliability (DAR) projects improve information and control capabilities for distribution systems. These projects focus on distribution challenges posed by distributed energy resources, clustered electric vehicle charging, and also mitigate outages by developing self-healing circuit technology. DAR projects will provide a consolidated solution to manage safety, reliability, and compliance obligations.

Transmission Automation/Reliability (TAR) projects address similar issues on the transmission system. These projects allow us to incorporate utility-sized intermittent power generation such as solar and wind energy in a safe and reliable manner. TAR projects also enhance data collection and automation to prevent wide-scale blackouts.

Asset Management & Operation Efficiency projects improve the efficiency of grid operations. These projects identify infrastructure replacements based on asset health rather than time in service; the projects help prevent critical equipment failure.

Security projects address both cyber and physical security. These projects address the increased security requirements associated with developing, implementing, operating, and managing Smart Grid systems and assets.

Finally, **Integrated & Cross-Cutting Systems** refer to projects that support multiple Smart Grid domains (e.g., communications, data management and testing). An integrated approach creates a platform to deliver benefits across utility operations and share those benefits with customers. Integrated systems also enable information sharing between the utility, service partners, and customers.

With respect to benefits, these projects are intended to provide benefits to customers in the form of better system reliability, improved safety and security, increased customer choice and reduced costs. The Department of Energy's Office of Electricity Delivery and Energy Reliability (DOE) developed a methodology to quantify Smart Grid benefits as part of the American Recovery and Reinvestment Act effort. For purposes of this report, SCE's benefits calculation is based on DOE's methodology, which has been tailored to SCE's operating environment.

It is worth noting that SCE's Smart Grid vision also carries with it risks and challenges. As noted in previous updates, the grid was initially designed to carry power in one direction from the generator to the end use consumer. Changes in state and federal energy policy (e.g., distributed generation and energy storage) are causing utilities to rethink the initial design and develop a means to create a more flexible delivery system that remains safe, affordable and reliable. This will likely include a transition from more conventional technologies to smarter, computer-based assets, capable of communicating and optimizing. This update details SCE's continued activities toward these goals. Importantly, this transition will be more cost-effective if the technologies are based on common standards. As SCE has maintained since Phase 1 of the Smart Grid OIR (R.08-12-009), standards are necessary to help ensure interoperability and maximize market participation.

The importance of cybersecurity to the utility industry and to SCE has increased as systems and data have become more integral to business operations, and as cyber threats continue to grow in number and sophistication. SCE continues to work with the government and private industry to develop and deploy critical infrastructure protection as evidenced by our implementation of a Common Cybersecurity Services (CCS) platform currently deployed on our bulk electric system. SCE continues to work with the vendor community to satisfy various cybersecurity protocols, including the National American Electric Reliability Corporation (NERC) CIP standards and the National Institute of Standards and Technology's (NIST) requirements. The industry anticipates that Federal Energy Regulatory Commission (FERC) and NERC will continue to require improved CIP reliability standards over the next several years, but is prepared to meet them, as cybersecurity is critical for Smart Grid development.

As part of its smart grid efforts, SCE proactively engages with and educates residential customers, business customers, governmental entities, and other stakeholders. During the Reporting Period, SCE continued to inform customers about online energy management tools and services and develop an outage application for smart phones. SCE also provided marketing, education and outreach to its customers regarding to its web presentment tools, time-of-use (TOU) rates (including rates for plug-in electric vehicles), and Budget Assistant.

In sum, SCE continued to advance its Smart Grid initiatives, consistent with the requirements of SB 17 and Decision (D.)13-07-024. SCE will continue to work with the Commission, fellow utilities, and stakeholders to modernize the grid in support of state and federal energy policy objectives.

II. Plan Update

In this section, SCE provides an update on proceedings and benefits associated to the Smart Grid Deployment Plan.

2.1 Proceedings

SCE's decision to invest in Smart Grid technologies and fund their deployment is significantly affected by the policy environment in which it operates. This section provides a summary of key state and federal regulatory proceedings and legislative activities impacting or with the potential to impact SCE operations.

The most significant proceeding affecting Smart Grid efforts is the General Rate Case (GRC), because the GRC provides SCE with the base funding and authorization to perform Smart Grid-related work. SCE submitted its most recent GRC Application for a 2018 test year on September 1, 2016.[8] As of the end of the Reporting Period, this proceeding is still open.

On December 4, 2014, the Commission issued D.14-12-004 closing the Smart Grid Rulemaking proceeding. Per the Decision, SCE will now submit the mandated Smart Grid Deployment Plan Updates and the quarterly American Recovery and Reinvestment Act (ARRA) project reports to the director of the Energy Division and the Executive Director. [9,10]

Within the Energy Storage rulemaking,[11] on September 15, 2016, the Commission issued D.16-09-004 approving the results of SCE's 2014 Energy Storage RFO Application, totaling 16.3 MW of distribution connected energy storage; and adopted the Joint IOU's protocol, which ensures above market costs are recovered from customers who depart bundled service after an energy storage resource is procured. Also on that day, the Commission issued D.16-09-007 approving SCE's 2016 Energy Storage Procurement Plan to procure, at a minimum, 20 MW of RA-only energy storage and innovative use cases such as distribution deferral. On April 27, 2017, the Commission issued D.17-04-039 dealing with Track 2 issues, leaving storage targets unchanged. The decision implements AB 2868 by directing the IOUs to each propose, in their 2018 Storage Plans, up to 166 MW of additional investments and programs in distribution storage. The decision creates a new "limiter" mechanism to adjust downward the procurement target for ESPs and CCAs based on the quantity of IOU storage eligible for cost allocation to ESPs and CCAs. Additionally, the decision allows energy storage resources to reduce their station power rate during charging activities to a wholesale rate, provided the storage device is responding to an ISO dispatch.

The Electric Program Investment Charge (EPIC) is administrated by the Utilities (PG&E, SCE and SDG&E) and the CEC. The EPIC Program provides funding for applied research and development, technology demonstration and deployment and market facilitation of clean energy technology. EPIC's budget is annually $162 million and is collected from customers using the following allocation: PG&E (50.1%), SCE (41.1%) and SDG&E (8.8%), resulting in SCE's triennial budget of approximately $40 million. The Utilities are limited to technology demonstrations and deployments. SCE has submitted and received Commission approval for two triennial investment plan applications addressing investments in years

[8] Application (A.)16-09-001.
[9] D.14-12-004.
[10] ARRA Projects: Tehachapi Wind Energy Storage Project (TSP) per Rulemaking R.08-12-009.
[11] R.15-03-011.

2012-2014 and investments in years 2015-2017. On May 1, 2017, SCE submitted its 2018-2020 Investment Plan Application[12] to the Commission for approval.

The 21st Century Energy Systems Project (CES-21) is a $35 million, five-year cooperative research and development agreement between SCE, PG&E, SDG&E and Lawrence Livermore National Laboratory (LLNL), which addresses cybersecurity and grid integration issues. Senate Bill (SB) 96 limits the CES-21 Program budget to $33 million for cybersecurity and $2 million for grid integration over a five-year period. SCE is just participating in the cybersecurity project that addresses machine-to-machine automated threat response. The cybersecurity project is in progress and on-track to conclude at the end of the five-year period. The Joint IOUs, along with the LLNL provide periodic briefings to Commission staff on a biannual basis.

On September 25, 2013, the Commission issued R.13-09-011 to enhance the role of Demand Response (DR) in meeting California's resource planning needs and operational requirements. The Rulemaking will establish policies to inform future DR program design. On September 29, 2016, the Commission issued D.16-09-056 resolving the remaining Phase Two and Phase Three issues. The resolution of the issues provide guidance to the IOU's on their 2018-2022 DR applications, which SCE filed[13] on January 17, 2017, to fund its portfolio of existing DR programs.

On September 1, 2016, SCE filed its 2016 Rate Design Window (RDW) Application[14] to, among other things, update its standard time-of-use (TOU) periods for non-residential customers. SCE's existing TOU periods have remained relatively unchanged for three decades, and are no longer aligned with the underlying economics of today's electricity costs and grid needs. This is largely the result of the influx of renewable generation, which has caused SCE's peak costs to shift later in the day. To account for this, SCE has proposed shifting its peak period from noon to 6 p.m. to 4 p.m. to 9 p.m. SCE has also proposed a super-off-peak period from 8 a.m. to 4 p.m. in the winter season to help enable appropriate consumption price signals in periods of more abundant renewable supply. Aligning TOU periods with underlying marginal costs will send more appropriate price signals to customers, which can influence customers' consumption patterns and work to reduce costs if customers are able to shift their load to lower cost periods. As of the end of the Reporting Period, this proceeding is still open.

The Commission issued an Order Instituting Rulemaking (OIR) to consider alternative-fueled vehicle programs, tariffs, and policies.[15] This rulemaking will continue the work started in R.09-08-009, to support California Executive Order B-16-2012, which sets a target of 1.5 million zero-emission vehicles on the roads in California by 2025.[16] On March 30, 2016, the Commission issued an Amended Scoping Memo and Ruling for the AFV OIR, to include within the scope of the proceeding the transportation electrification (TE) issues contained in SB 350, and reprioritize the broad policy activities in the AFV OIR.

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12 A.17-05-005.
13 A.17-01-018
14 A.16-09-003
15 R.13-11-007.
16 California Executive Order B-16-2012 was issued on March 23, 2012.

On September 14, 2016, Commissioner Peterman issued an Assigned Commissioner Ruling[17] directing the IOUs to file applications for programs and investments in Transportation Electrification (TE). The ruling provides the IOUs flexibility to apply for programs/investments in almost all transportation sections. On January 20, 2017, SCE filed its application[18] for a portfolio of investments and programs to help accelerate the adoption of electric vehicles (EV). The application proposed a portfolio of eight pilot projects and investment programs. This application will be the first in a series of possibly annual applications for funding of TE by SCE until the state achieves its 2030 and 2050 carbon goals.

In addition to Commission proceedings and filings, smart grid deployment is also affected by federal regulatory decisions, such as the CIP standards developed by the NERC and adopted by the FERC. CIP standards set a regulatory cybersecurity framework for protecting SCE's critical assets. The CIP V5 Standards were effective July 1, 2016. On January 21, 2016 FERC issued Order 822 approving NERC CIP Version 6 with staggered implementation schedules through 2018. The proposed standards are designed to mitigate the cybersecurity risks to bulk electric system facilities, systems, and equipment, which, if destroyed, degraded, or otherwise rendered unavailable as a result of a cybersecurity incident, would affect the reliable operation of the Bulk-Power System.

Additionally, SCE is actively evaluating the impact of complying with NERC Reliability Standard CIP-014-1 (Physical Security) requirements for its bulk electric system to comport with pending legislation SB 699. The purpose of CIP-014-1 is to enhance physical security measures for the most critical Bulk-Power System against physical attacks.[19] On June 11, 2015, the CPUC approved a new OIR[20] to establish policies, procedures, and rules for the regulation of physical security risks to the electric supply facilities (Phase 1), and to establish standards for disaster and emergency preparedness plans for electric and water facilities (Phase 2). During the reporting period, three workshops have been conducted in Phase 1, with a fourth workshop to be conducted in Q3 2017. Also, parties are working on reaching consensus on a straw proposal for a common framework to guide utility plans for physical security.

On August 14, 2014, the Commission issued R.14-08-013 to establish policies, procedures, and rules to guide California IOUs in developing their Distribution Resources Plan (DRP) Proposals. The Rulemaking also intends to evaluate the IOUs existing and future electric distribution infrastructure and planning procedures with respect to incorporating Distributed Energy Resources (DERs) into the planning and operations of their electric distribution systems. On February 9, 2017 the Commission issued D.17-02-007 on Track 2 field demonstrations. SCE's Demo C (Demonstrate DER Net Benefits) is approved, but with a modified budget and schedule. SCE's Demo D (Demonstrate High Penetration of DER) is approved. SCE's Demo E (Demonstrate a Microgrid) is not approved, due to the high cost and the lack of the specific reliability issue at the project location. On February 27, 2017, Assigned Commissioner Picker

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17 *Assigned Commissioner Ruling Regarding the Filing of the Transportation Electrification Applications Pursuant to SB 350.*

18 A.17-01-021.

19 On July 17, 2014 FERC issued a Notice of Proposed Rulemaking to approve CIP-014-1.

20 R. 15-06-009.

issued a Ruling[21] largely consistent with the Joint IOU proposal presented at the Growth Scenarios Workshop on February 10, 2017, which included a schedule for developing growth scenarios, formation of a Working Group and guiding principles. The ruling is the first substantive decision in Sub-Track 1 of Track 3. On April 19, 2017, two ACRs were issued.[22] One posed specific questions focusing in on issues that may be resolved in a PD and the other provided a framework for future activities of the ICA and LNBA Working Groups. On June 15, 2017, the Commission issued D.17-06-012 approving the Modified Demo E proposal.

In the IDER proceeding,[23] the CPUC held a workshop on September 22, 2016, aimed at developing the parameters and method of a Societal Cost Test (SCT). The objective is to adopt an SCT for use consistently across all DER proceedings. On December 15, 2016, the Commission adopted D.16-12-036 authorizing a utility incentive and procurement pilot in the IDER proceeding. The decision requires the IOUs to utilize recommendations from the Competitive Solicitation Framework Working Group's Final Report to procure DERs to defer or displace the needs of at least one, and up to four, traditional distribution infrastructure capital projects. The IOUs would receive a 4% pre-tax incentive for such procurement, applied to annual DER contract payments, if the deferral is successful. On February 9, 2017, ALJ Hymes issued a ruling regarding a SCT, which would include a Greenhouse Gas adder and an air quality value, along with a social discount rate. The SCT could be used to determine funding levels, conduct program evaluation, or be used in any other aspect of the Commission's evaluation of DER.

SCE is committed to supporting state and federal energy policy objectives. Moreover, SCE is committed to making its grid smarter, and maintaining reliability while improving interoperability through new technologies that can accommodate disparate generation at a reasonable price. However, the rate at which SCE is able to study, test, deploy and enable smart grid technology is largely dependent upon the pace and outcome of regulatory processes and proceedings.

2.2 Benefits

In this section, SCE provides an estimate of Smart Grid benefits accrued during the reporting period. In identifying and estimating these benefits, SCE leveraged the publicly-available methodology from the U.S. Department of Energy's (DOE's) Office of Electricity Delivery and Energy Reliability. Using this approach, SCE developed a set of smart grid assets, functions, and benefits, modifying DOE's terminology when necessary to reflect SCE's specific Smart Grid investments. For this annual report, SCE reviewed the status of all Smart Grid projects to determine which assets and functions were in place and producing benefits during the reporting period.

21 Setting Schedule for Submission of Distributed Energy Resources Growth Scenarios and Distribution Load Forecasting

22 1.) Requesting Comments on the ICA and LNBA Working Group Reports and 2.)Proposing Scope and Schedule for Long Term Refinement of ICA and LNBA.

23 R.14-10-003

SCE's methodology categorizes benefits into five areas:

1. Operational;
2. Reliability;
3. Demand Response/ Energy Conservation;
4. Environmental; and
5. Other.

Operational benefits consist of reduced and avoided costs of utility operations, including procurement, customer service and T&D costs. Reliability benefits include the societal value of avoided outages and reduced outage duration for all customer classes. Demand Response/Energy Conservation benefits are reflected in measured load impacts from SCE's DR resources. Environmental benefits include avoided greenhouse gas and particulate emissions. Finally, other benefits include areas that are difficult to quantify, such as safety and customer satisfaction. This annual report includes estimates of operational, reliability, and demand response/conservation benefits and provides descriptions of environmental benefits and other benefits.

Estimated benefits for the reporting period are summarized in the table below:

Estimated Smart Grid Benefits in the Reporting Period

Benefit Area	Reporting Period Value
Operational Benefits	$60,200,000
Reliability Benefits	$614,800,000
Demand Response/Energy Conservation Benefits[24]	$,14,900,000
TOTAL Estimated Benefits	**$689,900,000**

Operational benefits shown for the current reporting period[25] are associated with (1) mobile work management tools and processes developed under SCE's Consolidated Mobile Solutions (CMS) project, as described in greater detail in SCE's 2012 GRC[26] and (2) procurement benefits attributed to SCE-owned energy storage deployed in response to CPUC Resolution E-4791.

Reliability benefits come primarily from SCE's circuit automation program, which shortens the amount of time required to restore power to a portion of customers during an outage. Circuit automation is not new, and the benefits accrue from roughly two decades of deployment. In past reports, this benefit was estimated using a Value-of-Service (VOS) reliability model developed by the Lawrence Berkeley National

[24] Demand Response and Energy Conservation benefits are specifically attributed to demand response enables by Auto-DR technology and controllable programmable communicating thermostats for SCE's PTR-ET-DLC program.

[25] Refer to http://www.cpuc.ca.gov/general.aspx?id=4693 for benefit information from previous reporting periods.

[26] A.10-11-015.

Laboratory.[27] In support of SCE's 2018 GRC[28] filing, SCE has developed and implemented a more rigorous reliability forecasting methodology and has updated its VOS estimates; the improved approach indicates a significant increase in calculated reliability benefits relative to past reports.

Demand Response benefits are associated with commercial DR programs that use interval data, such as those gathered by Edison SmartConnect meters to calculate energy reductions. These programs include the Aggregator Managed Portfolio, Capacity Bidding Program, and Critical Peak Pricing. Participation in these programs can be enhanced, with corresponding benefits to customers, through AutoDR enablement. The MW of these resources are derived from the average ex post load impacts from 2015, which are based on the Load Impact Protocols adopted in D.08-04-050, and the avoided generation capacity value from the DR Cost-Effectiveness Template adopted in D.10-12-024.

Distribution and Substation Automation, and the communications networks that enable such automation, support realization of DER potential, enhancing the ability of DERs to provide new services. Environmental benefits in the form of reduced greenhouse gas emissions have resulted from several of SCE's smart grid initiatives. Energy storage deployment, peak demand reduction and energy conservation programs all result in fewer emissions. A reduction in truck usage due to the smart meter program has also produced lower emissions. This report does not provide an estimated value of these benefits. Other benefits resulting from the Smart Grid include a reduction in the risk of safety incidents affecting SCE customers and employees due to the circuit automation program, higher customer satisfaction resulting from improved outage response, and the availability of better customer data and options for managing energy use.

III. Projects Update

In this section, SCE provides an update regarding its deployment projects and pilot projects described in its July 1, 2011 Smart Grid Deployment Plan. The projects have been grouped in six categories:

1. Customer Empowerment;
2. Distribution Automation/Reliability;
3. Transmission Automation/Reliability;
4. Asset Management & Operational Efficiency;
5. Security; and
6. Integrated & Cross Cutting Systems.

Throughout Section III, the dollar amounts associated with specific projects refer to the total amount spent from July 1, 2016 through June 30, 2017.[29]

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[27] The LBNL model was published in 2009.

[28] A.16-09-001.

[29] Refer to http://www.cpuc.ca.gov/general.aspx?id=4693 for project and cost information from previous reporting periods.

A. Customer Empowerment

SCE's customer empowerment efforts support the Commission's Smart Grid vision which includes customers "who are informed about the Smart Grid and [are able] to use electricity more efficiently and save money." [30] In support of this vision, SCE's customer empowerment efforts will provide customers with accessible information regarding their energy information. Furthermore, SCE continues to develop rates and programs to encourage energy conservation and peak load reductions. SCE provides this energy information while protecting each customer's data privacy, in accordance with the Commission's decision adopting rules to protect the privacy of customer's electric usage data.[31]

Generally, projects in this area develop communication infrastructure, information systems, and energy management services, along with customer-facing tools, services, programs, dynamic rates and outreach capabilities. Furthermore, SCE's efforts will provide automated interval usage information to customer-authorized third parties.

The following discussion provides descriptions and updates regarding the customer empowerment projects.

3rd Party Smart Thermostat (PCT) Program	$3,000,000
Description: Although a retail market of smart meter connected Home Area Network (HAN) devices such as smart thermostats didn't emerge as anticipated, Internet connected (usually Wi-Fi) smart thermostats have been gaining traction with consumers. In order to take advantage of these DR capable devices that are already in the homes of many customers, SCE developed a study to partner with some of the leading Internet connected smart thermostat vendors and system providers to enroll these customers in a DR Program and utilize our smart meter interval data. Participating 3rd Party Partners (Nest and EnergyHub) recruited SCE customers with their compatible thermostats into the Save Power Day Program (using the PTR-ET-DLC profile created for this program). Participating customers received the same enabling technology incentive as customers with HAN devices ($1.25 per kWh reduced during events). When events are called, an OpenADR signal is received by the Participating 3rd Party Partners and they implement control strategies (pre-cooling, degree offset, etc.) on customer thermostats to maximize energy savings, while maintaining customer comfort. Start/End Date: 2013-2014 (Study), 2015-Ongoing (Program) Funding Source: A.12-12-017 (EM&T Funding), Customer Incentives paid from Save Power Day Program and D.16-06-029 Save Power Days Program Budget	
Update: After successfully running this project as a study for two years with approximately 3,000 customers participating, it was launched as part of the Save Power Day program in June 2015. By the end of June, there were 1,000 participants. As of April 2017, there are approximately 26,650 participants. SCE also recruited a third partner in WeatherBug joining in August of 2016. SCE	

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

[31] *See* D.11-07-056, Decision Adopting Rules To Protect the Privacy and Security of the Electricity Usage Data of the Customers of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, July 28, 2011.

continues to look for new partnerships to expand the base of qualified smart thermostats that support customer choice. SCE has a target of 35,000 participating customers by December 31, 2017.

Metering Capital Requirements	$67,000
Description: SCE plans to deploy additional Edison SmartConnect (ESC) meters to accommodate customer adoption of time-variant PEV rates through 2017. These meters will leverage the AMI network and part of back office systems deployed to acquire and manage PEV load data. Start/End Date: 2016-2017 Funding Source: GRC	
Update: During the reporting period, SCE installed a total of 271 meters for PEV customers. 231 customers selected TOU-EV-1 rate, 3 selected TOU-EV-3 (1 in 3-A and 2 in 3-B) rate, 36 selected TOU-EV-4 rate, and 1 selected TOU-EV-6 rate.	

Outage Notifications	$1,447,000
ONI Release 2a: Enable residential customers to also enroll and receive proactive digital maintenance and repair outage notifications via their channel of choice (e.g., email, voice or text message) and provide customers self-service tools to manage their outage contact information and notification preferences. Start/End Date: Jan 2015-May 2016 Funding Source: GRC Spend Jul 1, 2016 to Jun 30, 2017: $467,994 Update: Activities completed during this period included post go-live warranty support, identification and resolution of defects and transition of new capabilities to operational owners. **ONI Release 2b Part 1:** Improve the Outage Alert Preference Management self-service tools on SCE.com to be more simple and intuitive and add new search features in the employee outage alert preference management tools. Start/End Date: Jun 2016 -Jul 2017 Funding Source: GRC Spend Jul 1, 2016 to Jun 30, 2017: $447,989 Update: The project was successfully implemented in production on March 16, 2017. Activities completed during this period included design, construction, testing (integration, system, performance and user	

acceptance), implementation tasks, employee readiness activities such as training and post-implementation technical support.

ONI Release 2b Part 2:
Improve the timeliness and accuracy of outage alerts to end-use customers; simplify outage alert content; provide the reason for maintenance outages and enable new maintenance outage restore alerts.

Start/End Date: Jun 2016-Nov 2017

Funding Source: GRC

Spend Jul 1, 2016 to Jun 30, 2017: $531,300

Update:
The project will implement production on July 20, 2017. Activities completed during the above period include design, construction, testing (integration, system, performance and user acceptance) and employee readiness activities such as training.

DR Systems Enhancements	$2,007,000
Description: SCE owns and licenses a variety of systems used to dispatch and measure demand response events. These systems primarily consist of notification systems, load control dispatch systems, event status webpages, customer enrollment and reporting systems, and demand response bidding platforms. Start/End Date: 2016-2017 Funding Source: A.11-03-003	
Update: SCE continues to make modifications to its existing Demand Response (DR) portfolio processes and systems to create efficiencies with CAISO wholesale market integration. During the first quarter of 2017, SCE filed the 2018-2022 DR application to the CPUC to request these modifications. SCE requested changes such as partnering with additional third parties to extend additional technology offerings to participate in DR, reprogram meters to comply with CAISO settlements, and develop machine to machine automation from the CAISO award system to SCE back office systems to customer devices during program dispatch. SCE continues to participate in the second Demand Response Auction Mechanism (DRAM) pilot solicitation. Through this pilot, SCE procured 56.2 MW of Resource Adequacy (RA) for delivery in 2017 and included Local and Flexible Resources to Product Types in addition to System RA. A third solicitation for a two-year pilot concluded in April and is pending Energy Division approval of the contracts. The second DRAM will continue to utilize the Rule 24 program/process for third party direct participation.	

Rule 24 Click Through	$184,000
Description: In January 2016, Rule 24 was approved to support the Direct Participation for Demand Response Providers (DRPs). This allows DRPs to provide demand response programs to customers	

and receive compensation for reduction in usage. In order to show usage reduction, DRPs must receive customer authorized usage and billing data from the customer's utility company. To support this data transmittal, SCE had built manual processes to provide the data to the DRPs in order for the DRPs to claim savings at the CAISO. Unfortunately, the data was not being provided to the DRPs in time to determine if a customer is eligible to participate in the DRPs demand response program. In D.16-06-008, effective on June 6, 2016, the CPUC ordered SCE to implement a click-through "…electronic signature process to provide a demand response direct participation customer the means by which to verify and document the customer's consent to release its usage data to the third-party demand response provider." This "click through" option will streamline the existing Green button connect functionality for customers to authorize release of their data to their designated DRP. Start/End Date: 2016-2018 Funding Source: O&M and Balancing Account
Update: The project is currently in the Analysis Phase which consists of interactions between IT and business partners. Org Readiness and Training plans have been created and will be triggered in 3rd quarter 2017. A final decision on the advice letter is expected from the Energy Division by August 2017.

B. Distribution Automation/Reliability

Distribution Automation/Reliability (DAR) projects improve utilities' information and control capabilities for distribution systems. These capabilities may be used to address the complexities associated with integrating distributed energy resources and electric vehicles, advanced outage management, and/or volt/VAR control. DAR projects provide the ability to safely and reliably incorporate high penetrations of distributed energy resources by mitigating voltage fluctuations resulting from intermittent power generation. These projects would also provide the ability to safely and reliably incorporate the increasing load of charging electric vehicles (EV).

DAR would detect and isolate faults when they occur, immediately restore service to customers as soon as possible and provide information to customers about outages in real-time. "Self-healing" circuits will reduce the number of customers affected by system disturbances and enable faster service restoration. DAR would also provide optimization of voltage and reactive power on the system to enhance power quality and decrease energy consumption.

DAR helps enable electricity markets to flourish and helps deliver a Smart Grid that has the infrastructure and policies necessary to enable and support the integration of demand response, energy efficiency, distributed generation and energy storage.

Consolidated Mobile Solutions	$5,288,000

Description: Consolidated Mobile Solutions (CMS) will enable field personnel, system operators, and office workers to share real-time information related to software systems. The maps from these software systems will enhance SCE's safety, improve outage responsiveness, and contribute to SCE meeting its compliance obligations. CMS will reduce lost time, enabling the existing work force to be more productive. Start/End Date: 2010-2017 Funding Source: GRC
Update: Deployment to Grid Operations Troubleman and Substation Construction & Maintenance (SC&M) Apparatus was completed Q4 2016. The fourth CMS release was developed, tested and implemented on November 2016. Transmission, Distribution Underground Inspection (UDI) and E-crew deployment was completed Q2 2017. Remaining to complete Q3 2017 includes: hardware refresh of Apparatus and deployment of Transmission of Right of Way; stabilization activities; additional knowledge transition to our CMS Managed Services Provider (MSP) support teams; and project closure end of September 2017.

Circuit Automation	$3,860,000
Description: The primary purpose of SCE's Circuit Automation Program is to automatically or remotely restore power to customers after outages caused by faults. In providing this service, the Circuit Automation helps minimize the impact on customers of outages that occur in the ordinary course of business. The capabilities provided by the Circuit Automation Program are consistent with basic service provided by most utilities in this country. Start/End Date: 2010-Ongoing Funding Source: GRC	
Update: In order to maintain a reliable system, SCE has integrated remote control switches within its distribution system. Between July 1, 2016 and June 30, 2017, SCE installed 133 remote control switches and spent $3,860,000. SCE has recognized that automating distribution circuits can help improve overall system performance and increase the reliability of the system.	

Capacitor Automation	$500,000
Description: SCE's Capacitor Automation program automates existing manual capacitor controls and upgrades obsolete, first-generation automation equipment. Capacitor controls are used to remotely operate switched capacitor banks installed on the distribution system to provide voltage and Volt-Ampere Reactive (VAR) support. 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. Automating the control of these capacitor banks 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.	

Start/End Date: 2011-Ongoing Funding Source: GRC
Update: As part of its Capacitor Automation program, SCE is continuously deploying fully programmable capacitor controls (PCCs). By automating capacitor controls, SCE is replacing failing capacitor controls while improving voltage and VAR control. Additionally, SCE is adding the capability to remotely check and monitor capacitor bank operating status. During the reporting period, SCE installed approximately 390 PCC's and spent $500,000.

Distribution Energy Storage Integration (DESI) Program	$1,037,000
Description: The DESI program includes the deployment of several energy storage systems to provide value to local distribution circuits. The first project installed a battery energy storage system (BESS) with an active power rating between 2.0 MW and 4.0 MW, and usable stored energy capacity between 3.5 MWh and 4.0 MWh in a pilot deployment to support a primary distribution circuit that has problematic loading characteristics. This project measures the operating parameters of the BESS and determines the values created by the BESS. The first project plan and "lessons learned" are used as guidance for subsequent pilot deployments. Start/End Date: 2013-2017 Funding Source: GRC	
Update: DESI 1 continues to be a grid asset supporting the Scarlet 12kV out of the Orange Substation. During September 2016, distribution construction crews completed the installation of pole-mounted equipment in accordance with the approved Pilot Standard DESI 100P.1. This pilot standard involves the installation of an SEL-735 meter and 4G radio that collects and transmits circuit information (e.g., amps, volts, etc.) to support the operation of the DESI 1 battery energy storage system. Previously, DESI 1 was operating from partial circuit data collected at a local node near the Scarlet 12kV. The DESI 2 project planning is nearing completion. The Energy Storage Deployment team issued a purchase order to NEC Energy Solutions to install a 1.4MW/3.7MWh battery energy storage system. Initially, DESI 2 will support the Integrated Grid Project in two key areas, a virtual microgrid, and a high DER penetration circuit. In the microgrid scenario, DESI 2 will be able to zero out the targeted 1.25 MW peak load for 3 to 4 hours allowing time to exercise the control system with normal variation in load. For the high DER penetration scenario, DESI 2 will allow the control system to perform optimization of the circuit power flow and voltage control over a range of generation and load cases for a significant period of time to experience normal load and generation fluctuations. Recently proposed changes to the system specifications and the statement of work are being negotiated with NEC Energy Solutions. The ESD team expects the DESI 2 system to be operational in the first quarter 2018. The DESI 3 project is a smaller system than originally proposed due to the lack of available land. DESI 3 will be a single 710kW/510kWh system connected to the Cadmium 12kV circuit out of Camden Substation in Santa Ana. SCE's Real Properties organization is negotiating an easement to construct DESI 3 on private property. This has been a lengthy process, but the ESD team expects DESI 3 to be operational in the first quarter 2018. DESI 3 will support the Integrated Grid Project by being part of	

other distributed energy resource (DER) devices on distribution circuits out of Camden Substation. DESI 3 will provide a controllable reactive power resource that will be used to help manage voltage on circuits that contain high penetrations of variable renewable generation resources. The real power output of the battery system will be used to help shape and optimize the circuit loading to prevent overloads on these circuits. The control capabilities are expected to reduce the need for capital investments for circuit upgrades and allow the integration of increased amounts of DER.

Outage Management System	$5,054,000
Description: The Outage Management System (OMS) Refresh will deliver a system with the vendor's most current software and hardware in order to improve the level of system availability, usability, and reliability required to support the needs of our business organizations and customers, as well as provide strategic smart grid-based enhancements to the system. For example, the Refresh will provide a range of enhanced smart meter functionality including: integrated ability to perform an instantaneous voltage read on a customer's meter, including groups of meters; and, the ability to energize outage locations based on a percentage of Power Restoration Notifications received from the smart meters. The Refresh Project will be delivered in three releases: • Technology Release – Implementation of the COTS package to the newest version 6.5 • Network Connectivity Model Release– Implementation of an end-to-end outage modeling through the use of a Transmission, Sub-Transmission, and Substation As-Is Connectivity Model • Enhancement Release – Implementation of a series of enhancements that take advantage of the new version's capabilities and additional smart meter integration Start/End Date: 2014-2017 Funding Source: GRC	
Update: The Technology release has been implemented. The Trans-Sub Model is scheduled for system implementation in Q3 2017, with a staged system-wide roll-out planned for the remainder of 2017. The Enhancements Release is expected to be divided into several sub-releases that will be implemented through the first half of 2018.	

Distribution Volt/Var Control (DVVC)	$1,124,000
Description: The primary purpose of DVVC is to centralize control of the field and substation capacitors, in order to coordinate and optimize voltage and VARs across all circuits fed by a substation. Supervisory-controlled distribution substation capacitors and existing standard automated distribution field capacitors on distribution circuits are leveraged to reduce energy consumption, while maintaining overall customer service voltage requirements. Deploying DVVC at SCE as a grid integration solution will optimize voltage levels on the distribution system, reducing excess voltage, which results in avoided energy procurement and capacity costs, while not compromising the safety and reliability of service. SCE estimates these avoided energy procurement and capacity costs to provide a 1% actual savings in energy costs for customers per 1% reduction in voltage.	

Start/End Date: 2015 - Ongoing Funding Source: GRC
Update: The implementation of DVVC for the reporting period has been successfully completed at 182 substations throughout the SCE territory.

Equipment Demonstration and Evaluation Facility (EDEF)	$15,900,000
Description: Equipment Demonstration and Evaluation Facility (EDEF) is a new 12kV test circuit which allows SCE engineers to perform evaluations of largely unproven emerging technologies on energized high-voltage equipment and distribution circuits under real world conditions to determine the likelihood of operational successes and failures prior to deployment. Testing capabilities include; simulating various fault magnitude and conditions on the 12kV distribution circuits, performing simultaneous testing of up to 10 automated fault interrupting devices including overhead, padmount and underground construction/installation methods validation, and distribution and substations automation. The development and construction of an SCE owned energized EDEF will improve both engineering and power delivery processes by providing insight into equipment capabilities and operations. There is increasing pressure to replace and upgrade infrastructure, coupled with the uncertainty around emerging technologies. Thus it is increasingly imperative to validate equipment performance in an energized facility prior to piloting. Start/End Date: 2015-2017 Funding Source: Capital	
Update: Control construction has started and is scheduled to be completed by Oct. 2017.	

Aliso Canyon Energy Storage	$40,712,000
Description: In order to address the shutdown of the Aliso Canyon natural gas storage facility and resulting risk of outages, CPUC issued Resolution E-4791, which ordered SCE to hold an energy storage solicitation to address electric reliability risks and also allowed SCE to submit applications for utility-owned storage. In response, SCE managed the development and deployment of the Aliso Canyon Energy Storage (ACES) projects A & B (also known as Mira Loma Units 2 & 3) located adjacent to SCE's Mira Loma Substation in Ontario, California. Start/End Date: 2016-N/A Funding Source: A.17-03-020	
Update: The two identical 10 MW/40 MWh energy storage systems (totaling 20 MW/80 MWh) are co-located in one facility and were deemed commercially operable on December 30, 2016. The systems are bid into CAISO wholesale generation market for day ahead and real time dispatch.	

C. Transmission Automation/ Reliability

Transmission Automation/Reliability (TAR) includes projects that provide wide-area monitoring, protection and control to enhance the resiliency of the transmission system. TAR also includes projects to provide the ability to safely and reliably incorporate utility-sized intermittent power generation such as centralized solar and wind energy. TAR projects help mitigate voltage fluctuations resulting from integrating intermittent resources.

The wide-area capabilities of TAR provide the ability to monitor bulk power system conditions, including but not limited to voltage, current, frequency and phase angle, across the IOU geographic area in near real-time. This functionality provides system operators with current information about emerging threats to transmission system stability, enabling preventive action to avoid wide-scale black outs. In addition, the wide-area capabilities of TAR also include projects for coordination of high-speed communicating transmission protection equipment that detect conditions in the transmission systems and automatically respond to stabilize the system.

There are no active projects in this category during the reporting period.

D. Asset Management & Operational Efficiency

Asset Management & Operational Efficiency (AMOE) enhances monitoring, operating and optimization capabilities to achieve more efficient grid operations and improve asset management. AMOE includes projects that will allow SCE to manage the maintenance and replacement of energy infrastructure based on the health of the equipment versus a time-based approach. This functionality will prevent failures of critical energy infrastructure as well as manage costs associated with maintaining and replacing equipment.

Online Transformer Monitoring	$1,707,000
Description: Field devices will collect real-time information about the health of transmission and distribution system infrastructure. The particular field devices that enable equipment monitoring depend on the equipment targeted for monitoring. SCE uses Dissolved Gas Analysis (DGA) technology and bushing monitoring devices for bulk power transformers. SCE has targeted a total of 101 500-kV (AA) and 143 230-kV (A) transformer banks at substations to deploy online transformer monitors. This program will improve transformer reliability, reduce failure impacts, identify units in urgent need of repair or replacement, realize the full transformer useful life, and a substantial reduction of overall transformer operating risks. In addition, this pilot will provide substation operators with information regarding the condition of transformers within their substation, therefore giving them the ability to quickly de-energize a transformer showing signs of trouble. This results in a positive impact to customers due to early identification of potential Bulk Electric System Transformer Failures, preventing collateral damage of an unidentified failure. Start/End Date: 2009-2021 Funding Source: Capital	

Update: This year's testing of data from RTU, to the back office and to the outside vendor was successful. Currently, SCE is trying to resolve hardware and software issues so that a substation RTU can provide information for multiple transformers from multiple substations to the back office.

E. Security

Physical and cybersecurity protection of the electric grid is essential and becomes more important as the Smart Grid is deployed. The communications and control systems that enable Smart Grid capabilities have the potential to increase the reliability risks of Smart Grid deployments if they are not properly secured. The Security program includes a comprehensive set of capabilities to address the increased physical and cybersecurity requirements associated with the development, implementation, operation and management of Smart Grid systems and edge devices. These projects would place and execute security throughout the network to resist attack, manage compliance and risk, and support security from the physical to application layers.

The Common Cybersecurity Services (CCS) platform project was completed and deployed during the 2016 update reporting period.

F. Integrated & Cross Cutting Systems

Integrated and cross-cutting systems refer to projects that support multiple Smart Grid domains, such as grid communications, application platforms, data management and analytics, advanced technology testing, and workforce development/technology training. An integrated approach helps to ensure that investments are managed efficiently while creating the platform to deliver a stream of benefits across utility operations and to customers.

Integrated communications systems provide solutions to connect and enable sensors, metering, maintenance, and grid asset control networks. In the mid-to-long term, integrated and cross cutting systems will enable information exchange with the utility, service partners and customers using secure networks. Data management and analytics projects will improve SCE's ability to utilize new streams of data from transmission and distribution automation and Smart Meters for improved operations, planning, asset management, and enhanced services for customers.

Advanced technology testing and standards certification are a foundational capability for the utilities to evaluate new devices from vendors and test them in a demonstration environment prior to deployment onto the electric system. This reduces the risks associated with new technology projects, and helps the utilities maximize technology performance and interoperability.

Workforce development and advanced technology training enable the successful deployment of new technologies, ensuring that the utilities' workforces are prepared to make use of new technologies and tools, maximizing the value of these technology investments.

Advanced Technology Fenwick Labs	$1,337,000

Description: SCE continues to implement smart grid technologies to create a smarter, safer and more reliable energy future. This grid of the future will provide customers with advanced tools and resources that enable informed and responsible energy consumption, and better serve customers by achieving an appropriate balance between energy policy and safety as well as reliability and affordability. Achieving this balance is a challenge, as the electric grid is an immense and complex system. To help ensure proper operation, rigorous technology evaluation must take place in a controlled environment before smart grid technologies are deployed on the grid. Thus, SCE developed the Advanced Technology Fenwick Labs to provide an integrated platform for evaluating the safety and operability of Smart Grid technologies without impacting customers by testing on distribution circuits or other equipment. Start/End Date: 2011-N/A Funding Source: GRC
Update: In order to continue providing a controlled testing environment, SCE continues to make the necessary enhancements to the Advanced Technology Fenwick Labs facility and its associated test equipment. This allows SCE to effectively and rigorously evaluate smart grid technologies safely and without impacting the grid or its customers. The following updates were made to the SCE Advanced Technology Fenwick Labs during the reporting period: **Communications and Computing Lab:** In an effort to keep the Lab testing network up to date a new network switch and backup tape drive were purchased to replace aging equipment totaling $33,000. **Substation Automation Lab:** In 2016 $3,000 was spent to evaluate a Substation meter with upgraded communications protocols and configuration files in compliance with IEC 61850 standards. Also $327,000 in relays and a circuit breaker simulator for $6,000 were purchased to further expand our abilities to simulate large substations. **Distribution Automation Lab:** $169,000 was spent on protective relay test sets to provide the capability to run multiple tests simultaneously. **Garage of the Future:** In 2016 $97,000 was spent on a photo voltaic simulator to test smart inverters by simulating a solar array. **Power Systems Lab:** In 2016 $183,000 was spent on relays, $150,000 on a gird simulator, and $142,000 on Real Time Data Simulator upgrades to expand the capabilities to simulate distribution circuits in the lab environment. An additional $67,000 was spent new oscilloscopes and $160,000 was spent on protective relay test sets to further support distribution circuit simulations.

Distribution System Efficiency Enhancement Project (DSEEP)	$5,099,000
Description: The Distribution System Efficiency Enhancement Program (DSEEP) consists of servicing and expanding the NETCOMM wireless communication system. The NETCOMM system provides the radio communication infrastructure to remotely monitor and control SCE's distribution automation devices. These automation devices include all of the devices deployed under the Circuit Automation and Capacitor Automation programs described above. Start/End Date: Ongoing	

Funding Source: GRC
Update: SCE added 1,432 distribution automation devices during the reporting period. Additionally, SCE added 38 infrastructure radios, extending communication to the new devices. These new devices include Radio Controlled Switches, New Capacitor Banks, and Automated Reclosers. The program also maintained radio infrastructure to existing devices. Maintenance efforts supported 628 automation device replacements, and 193 packet radios to maintain network performance levels. The maintenance activities also included replacing 413 end-of-life battery-backed radios.

Charge Ready Program	$5,741,000
Description: The Charge Ready Program is an initiative to deploy electric vehicle (EV) charging stations at long-dwell site locations where EVs are parked for four hours or more (including workplace, multi-family dwellings, fleet parking, and destination centers). In addition, SCE also conducts market education to develop awareness about EVs and the benefits of fueling from the grid. Start/End Date: 2016-On-going Funding Source: Application/balancing account	
Update: SCE launched the Phase 1/Pilot of the Charge Ready Program in May 2016 after receiving approval from the Commission in April 2016. As of June 2017, SCE has 72 sites and 1,087 ports committed for overall deployment. SCE completed infrastructure for 16 sites and 200 ports.	

IV. Customer Engagement Timeline

The common template for the Annual Reports, which was adopted by D.13-07-024 and initially proposed by Commission Staff in the March 2012 workshop report, requires the IOUs to include a customer roadmap that provides an overview of the IOU's customer engagement plan. SCE included its initial customer roadmap as Section IV of its 2012 Annual Report. The general outreach approach and strategy presented in the 2012 Annual Report has not changed and is not repeated in this report.

The common template requires the IOUs to include the following information in their Smart Grid Annual Reports: (1) a timeline that connects specific projects with specific marketing and outreach efforts, and (2) specific steps to overcome roadblocks, as identified in the workshops. As described in the 2012 Annual Report, SCE expanded on the sample template by recognizing that certain ME&O efforts are not confined to a single calendar year. Consistent with this approach, SCE provides its Customer Engagement Timeline (see figure below), which presents the appropriate initiatives provided in SCE's Customer Engagement Baseline and Roadmap Summary, and identifies the anticipated Smart Grid related ME&O efforts by year. Consistent with its GRC and DR application cycles, SCE provides such information from 2012 to 2017.

Customer Engagement Timeline (2012-2017)

	2012	2013	2014	2015	2016	2017
Customer Premise Devices						
A. Near Real-Time Usage (HAN)	X	X	X	X		X
Online Tools						
B. Integrated Audit Tool	X	X		X	X	X
C. Web Presentment Tools	X	X	X	X	X	X
D. Budget Assistant	X	X	X	X	X	X
E. Green Button Download My Data	X	X	X			
F. Green Button Connect My Data		X	X	X	X	
G. Mobile-Optimized Outage Center	X	X	X	X		
Rates and Programs						
H. Save Power Day (PTR)	X	X	X	X		
I. PEV Time-of-Use Rates	X	X	X	X	X	X
J. Residential TOU Rates				X	X	X

X = SCE or third party ME&O to support this initiative.

The common template also requires the IOUs to provide the following information for each identified Smart Grid related ME&O effort:

- Project description;
- Target audience;
- Sample message;
- Source of message;

- Current road blocks; and
- Strategies to overcome roadblocks.

Thus, as it did in the 2013 Annual Report, for each initiative identified in the above figure, SCE has provided such information in Appendix 1 of this report. In addition to discussing the initiatives identified above, Appendix 1 also includes SCE's customer engagement activities for certain pilots and demonstration projects and for conceptual projects.

V. Risks

In this section, SCE provides an overview of activities related to helping ensure grid reliability for its customers. The sections below provide an overview of the motivation behind developing open standards for Smart Grid infrastructure and cybersecurity investments and solutions. The motivation behind developing a smarter grid and its associated architecture remains consistent with those presented in SCE's 2011 Smart Grid Deployment Plan (A.11-07-001) and approved in D.13-07-024.

A. Introduction – Smart Grid Motivation

Progressive policy objectives and customer adoption continue SCE's efforts to integrate renewable resources, distributed generation, electric transportation, and energy storage. A thoughtfully designed, smarter electric grid will allow SCE to utilize new energy technologies to monitor, predict, and control the increasing adoption of renewable and distributed resources. The primary risks associated with the introduction of emerging technologies in general are: 1) Technology Maturity; 2) Market Structure/Regulatory Uncertainty; and 3) People/Process Change Management.

The technology evolution challenge is well understood and can be characterized through the following areas:

1) Technology evolution obsolescing existing infrastructure
2) New technology adoption being obsoleted prior to the asset's complete lifecycle
3) New technology adopted to interface to other technologies that become obsoleted
4) Misalignment of depreciation rules with technology lifecycle
5) General misalignment with depreciation rules and revenue requirements (i.e. discontinuous impacts on rates with accelerated depreciation)

The market and regulatory uncertainty present another host of challenges including the following:

1) Market structure uncertainty creating uncertainty on what entity should build and own the infrastructure resulting in reduced infrastructure investment overall
2) Market structure uncertainty creating uncertainty in the rate of technology adoption and infrastructure required

3) Regulatory input to the market structure possibly sub-optimizing the market and therefore creating misalignment with infrastructure requirements and ownership

4) Customer and third parties (e.g. aggregators) interaction and acceptance of market will evolve and influence market success/failure

The people and process issues include:

1) Significant changes in process and impacts on roles and responsibilities

2) Diverse perspectives (e.g. utilities, customers, regulators, 3rd parties) will require significant consensus building and delays may create sub-optimal results

3) Resistance to change from perceived or real failures from market/regulatory solutions creating a perception of resistance to change

These risks are mitigated and challenges managed through mechanisms like comprehensive testing of emerging technologies in lab environments, demonstration projects to further test technologies and concepts, and structured implementations of deployable technologies on the grid. The smarter grid envisioned through this deployment plan requires not only consensus on roadmaps and projects, but also fact-based results from realistic and accurate simulations, laboratory testing, demonstrations, and thoughtful implementations of emerging, smart technologies.

The Distribution Resource Plan process is working to encourage a thorough understanding across multiple stakeholders of the challenges and opportunities of high penetration of renewable and distributed energy resources. The demonstration projects proposed and the associated workshops associated with each demonstration project are mitigating opportunities to develop and deploy a modern infrastructure that attempts to optimize the technology decisions made by the utility as well as customers and resource providers. This collaborative effort and early demonstration of key technologies and processes is critical to informing stakeholders and reaching consensus.

B. Smart Grid Architecture Challenges

We are shifting today's electric grid from a system that is robust and reliable largely due to the basic laws of physics to a smarter electric grid that increasingly relies on technology to maintain stability and achieve a higher level of resilience. To do this we must obtain an in-depth understanding of systems theory, power systems, computer science and utility operations. Applying these diverse and specialized disciplines in a coordinated approach that yields cost efficient, manageable and reliable solutions requires a clear Smart Grid strategy and architecture approach. The key architecture challenge in evolving the electric grid is to help ensure that the introduction of automation, connectivity and advanced control systems do not create a system that is too complex or too fragile to manage.

Utilities have tended to rely heavily on highly customized solutions that were organized in a silo of proprietary devices, communications, security, configuration and control systems. This approach is commonly known as "security by obscurity." While this approach was efficient for each individual project with clear scope, schedule and cost objectives it results in a higher cost of maintenance and operations and a higher cost of new capabilities because each silo requires integration. If this approach is applied to grid modernization, the result will be a costly and fragile infrastructure that will impact grid reliability. An integrated approach to systems design, coupled with a common services architecture, is required to overcome this architecture challenge.

C. Cost-Efficient Smart Grid Design

A reasonably cost-efficient approach to deploying Smart Grid capabilities involves organizing technologies and systems into loosely coupled, standards-based layers capable of supporting common services. A Smart Grid common services architecture delivers the capability for any device in the forward deployed networks to access common services (such as cybersecurity, device management, network monitoring, etc.) in SCE's control centers. The common services architecture supports multi-vendor interoperability by enforcing standards across the architecture and drives implementation and operational costs down by simplifying the systems design. We simplify systems design by eliminating silos that extend from the application layer through the security, communications and device layers.

Over the past several years, SCE has been working to develop a Common Cybersecurity Service based on the premise that the level of automation and connectivity that is being introduced through grid modernization efforts requires military-grade cybersecurity to help ensure grid reliability in the face of increased cyber vulnerabilities introduced by new Smart Grid technologies.

D. Standards Overview

SCE has a long history of supporting the development of open standards. SCE recognizes that standardization of key areas can yield benefits to both consumers and service providers. Such benefits include enabling market innovation, reducing complexity, reducing equipment costs and protecting investments necessary to help ensure long term deployments. In addition, participating in standards development gives SCE the ability to prevent vendor "lock-ins" and to foster interoperability with legacy systems. Furthermore, SCE's participation in standards development brings extensive technical knowledge and experience along with utility credibility to the relevant working groups and organizations. SCE's approach to standards and interoperability includes supporting the development of the actual standard, laboratory testing and evaluation, and field trials.

SCE has identified over 70 standards of interest for Smart Grid development. Of these 70 standards, SCE's Advanced Technology organization is currently supporting the development of over 40 standards. These standards are found in specific areas, including system integration/architecture, data formats, communications, security and electrical interconnections/power quality. Many of these standards are being developed by the Institute of Electrical and Electronics Engineers (IEEE) and the International Electrotechnical Commission (IEC). SCE is or has been involved in the development of standards, testing and verification within these organizations, including:

- IEEE P2030: Guide for Smart Grid Interoperability
- IEEE1547: Distributed Energy Resource Interconnection Standard
- IEC 61850: Substation Automation

- IEC 62351: Power systems management and associated information exchange – Data and communications security
- Rule 21: California IOUs Standard to interconnect of distributed generation
- UL1741: Standard that mainly fallow IEEE 1547 but will incorporate a revision to California Rule 21

It is important to acknowledge that extensive involvement in standards development can pose many challenges to an organization. Such challenges include finding internal resources, both human and financial, to support the relatively long and exhaustive process. Standards often require fairly senior staff that is experienced and knowledgeable. Senior staff is then under significant pressure to not only support important core job functions but to also support the standards development. From a financial perspective, organizations not only need to finance staff for participating in standards development and paying applicable fees, but additionally some organizations resort to expensive consultants to fill in gaps when full time staff is severely impacted and/or unavailable. Specifically, participation in IEC standards can be rather difficult for regional electrical utilities to justify travel overseas.

Since 2013 SCE has been reducing its involvement with many smart grid standards. The reduction in participation stems from the fact that many of the standards that used to be infant or nonexistent are now mature enough be demonstrated. Standards like Smart Energy 2.0, OpenADE and OpenADR2.0 are available and ready for use. SCE helped drive and mature standards during the early days of smart grid technology and now has made a strategic decision to continue supporting the industry by focusing on the application and demonstration of these standards through continued involvement in some industry alliances (such as the OpenADR Alliance) and by requiring open standards for program participation. SCE also still maintains some involvement in key standards groups including IEEE, SAE and IEC.

SCE has been testing U.S and European Solar PV Inverters where it acquired extensive knowledge of their performance. Furthermore, this testing has provided assessment of what advanced inverter features can make an impact and provide grid support during higher penetration of these resources. SCE with sponsorship of DOE has been installing power quality monitors in the distribution system to gather actual field data in order to propose standards that will be meaningful and provide actual benefits to the grid. Since 2013, SCE has been proactively involved in California Rule 21 Smart Inverter Working Group. This standard created the first set of advanced features of solar PV inverter in the U.S. These features are meant to reduce their effects of higher penetrations in the grid. SCE has been also strongly involved with the IEEE1547 where it has been providing technical support to this standard. The technical support includes field knowledge of distribution circuit performance, laboratory testing knowledge on how solar PV inverters perform, and what advanced features would be beneficial to the U.S. grid. SCE has published over 30 reports and research papers (DOE, IEEE, etc.) on solar PV inverters that has been used to the development of standards.

1. NIST Smart Grid Standards Coordination

The 2007 Energy Independence and Security Act (EISA) gave the National Institute of Standards and Technology (NIST) the “primary responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of Smart Grid devices and systems." To achieve this mandate, NIST devised a three-phased approach to identify an initial set of standards, while providing a robust process for continued development and implementation of standards as needs and opportunities arise and as technology advances.

In 2009, NIST created the Smart Grid Interoperability Panel (SGIP) as a public/private partnership to coordinate the identification and development of Smart Grid standards. Since then the SGIP has grown to an organization representing twenty-two stakeholder categories and over 770 member organizations ranging from electric utilities to consumer electronics providers. One of the obligations of the SGIP is to produce and maintain a Catalog of Standards that could be used for developing and deploying a robust and interoperable Smart Grid.[32]

SCE is a strong supporter of the NIST/SGIP standards process. Since its onset, SCE has participated in the effort and held leadership positions within the governing board, the architecture committee and various Priority Action Plans (PAPs). SCE's director of Advanced Technology (AT) is a former governing board member for the "at-large" category. Additionally, AT's director of Engineering Advancement is a former member of SGIP's Implementation & Methods Committee (IMC). Furthermore, SCE has received various SGIP recognitions for its efforts in PAPs. SCE has participated in the first 16 PAPs, including:

- PAP 5: Standard Meter Data Profiles
- PAP 8: CIM for Distribution Grid Management
- PAP 11: Common Objective Models for Electric Transportation
- PAP 15: Harmonize Power Line Carrier Standards for Appliance Communication in the Home

PAPs have been an effective tool in identifying gaps among Smart Grid standards while providing standards development organizations (SDOs) with meaningful recommendations. However, PAP groups occasionally expand their focus beyond the immediate task. PAPs require proper NIST/SGIP leadership and oversight to avoid "scope creep." SCE has demonstrated this leadership by providing sound technical advice.

SCE remained a committed leader of the NIST standards effort through its final transition to the SGIP. SCE's decision to withdraw from the SGIP came when it was time to focus on system demonstrations and deployments. Resources that were previously allocated to standards development were transitioned to large demonstration projects such as the Irvine Smart Grid Demonstration (ISGD) project.

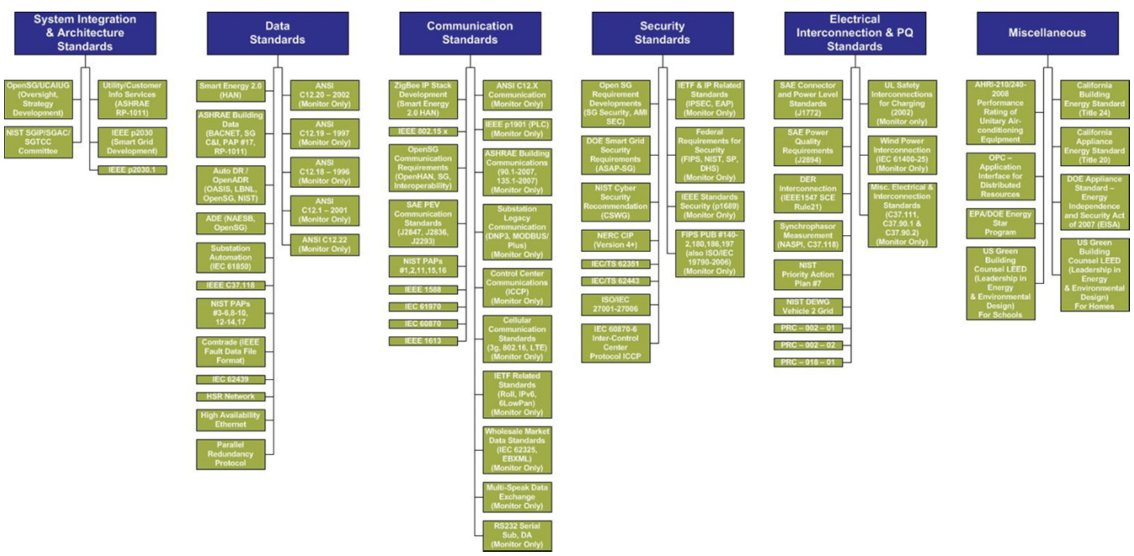
2. Standards Development

SCE's vision of a Smart Grid requires developing, evaluating and implementing open standards. SCE identified five categories that represent the bases for developing the Smart Grid: System Integration & Architecture, Data, Communication, Security, and Electrical Interconnection standards. SCE has identified existing standards within these major categories and identified "gaps" within the existing standards. SCE prioritized the standards and assigned resources to either lead, support or monitor the

[32] Energy Independence and Security Act of 2007, Title XIII, Section 1305.

particular standard. Using this process, SCE identified over seventy applicable standards and assigned resources to lead or support over forty standards. Some of the more notable standards either led or actively supported by SCE include:

- IEC 61850: Substation Automation
- Smart Energy 2.0: Home Area Network Communications
- NAESB ESPI: Automated Metered Data Exchange (e.g. Green Button)
- SAE J2836 & J2847: Electric Vehicle to Grid Communications
- SAE J2894: Electric Vehicle Charging Power Quality
- IEEE 1547: Distributed Energy Resources Interconnection
- ANSI C37.118: Synchrophasor Measurements
- IEEE P2030: Guide for SG Interoperability of Energy Technology
- OpenADR: Automated Demand Response
- Rule 21: California IOUs Standard to interconnect of distributed generation
- UL1741: Standard that mainly fallow IEEE 1547 but will incorporate a revision to California Rule 21

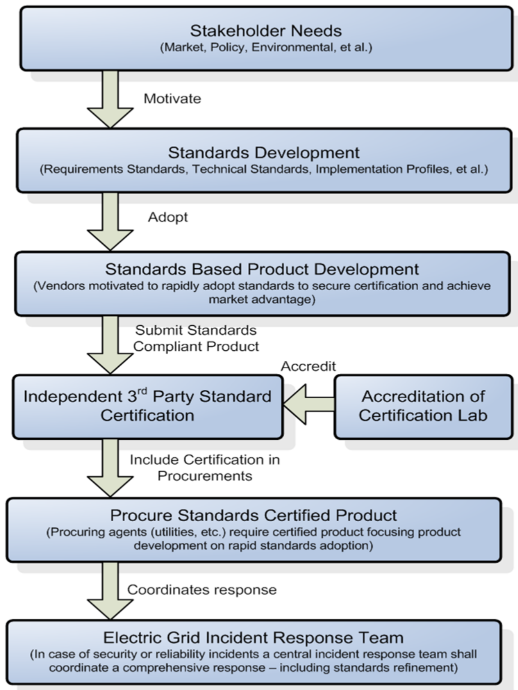


*SCE's Categorized List of Smart Grid Standards

3. *Standards Conclusion*

SCE leads the industry in its development and support of interoperability standards. The strategic standards development effort is focused on enabling grid modernization while maximizing system reliability, safety and customer value. SCE believes that proper standards development and adoption will ultimately lead to minimized risk to full Smart Grid deployments.

SCE continues to believe that standards are the key to minimizing risk and advancing the deployment of smart grid technologies. This is why SCE is now focus on demonstration of standards in order to encourage product manufacturers move to the "standards based product development" stage of the standards life cycle. Until product manufacturers adopt these standards it will be nearly impossible for electric utilities adopt. SCE is helping along this process by introducing a series of technology demonstrations and pilots that will hopefully lead to the systematic adoption of the smart grid standards portfolio.



* Standards Life Cycle

E. Cybersecurity Overview

The importance of cybersecurity to the utility industry and to SCE has expanded as systems and data have become more integral to business operations, and as the electric infrastructure has become more essential to national commerce and communication capabilities. Cyber attacks are continually growing in number and sophistication, and the availability of cyber weapons is on the rise as well. Therefore, maintaining a strong defense against cyber-attacks requires a continually evolving set of strategies. SCE's cybersecurity strategy continues to adhere to industry standard NIST 800-53 framework and "Defense-in-depth" practices that utilize a central set of services which allows more cost effective system management and a more robust cybersecurity posture. It is paramount to the success of securing the electric grid that cybersecurity system engineering principles achieve cybersecurity risk reduction while aligning with operational requirements. The following cybersecurity system engineering principles will govern the implementation of our grid cybersecurity deployments in the future.

- Maximize Isolation from Internet Facing Technology Service Layers
  The most common threat vectors are malicious code delivered through web pages, sophisticated malware sent through email, and compromise of external facing systems with known vulnerabilities. All of these threat vectors are perpetrated via the Internet and are risks SCE's office automation networks face as part of doing business. Electric grid networks have no need for Internet services and must have their supporting service layers isolated from these threats. This requires dedicated service layers to support grid systems and minimizing cross-domain functions. This does not mean all systems must be individually isolated, but IT systems supporting Internet facing services inherently carry higher risk that should not be transferred to the electric grid through shared services when avoidable.

- Centralized Monitoring and Response
  Establishing centralized monitoring across grid assets is critical to advancing SCE's grid cybersecurity posture. Systems isolated from central monitoring force SCE into a disjointed and reactive security posture. There is far greater cost to remediate a cybersecurity incident when forced into a reactive posture than heading off an incident with early detection. This is especially true in the event of a coordinated attack across multiple systems simultaneously. Cybersecurity architecture must be able to support centralized detection of threats across systems to facilitate incident response coordination to minimize incident impact.

- Nonrepudiation of System Activity
  The greatest potential threat impact to SCE control systems would be from a malicious insider. Insiders have the ability to use their privileged physical and electronic access to compromise systems or add unauthorized systems to grid networks for nefarious purposes. Establishing nonrepudiation and attribution of all system activities to an individual is the greatest deterrent to an insider threat. This requires a combination of preventative and detective controls that force users and devices to identify and authenticate themselves prior to being granted access and enables correlation of all activity in support of centralize cybersecurity monitoring and response.

- Grid System Network Segmentation
  In the event of a cybersecurity incident, it is imperative that a compromised system can be segmented from other control systems to contain a breach. Control systems that are architected in a flat network design, relying upon each other for operation, reduce the ability to contain threats. Each control system must have the ability to operate on its own and automated triggers for segmentation upon breach detection are critical to minimizing the potential impact from attack.

- Operational Alignment with Technology
  Deploying advanced cybersecurity technology without operational alignment and process integration does very little to reduce risk. Grid system operations have evolved around the organizational unit providing custodianship to each individual grid system. The future cybersecurity architecture must align with operations support groups to prevent disruption of operations and facilitate coordinated response to cybersecurity threats.

- Legacy Grid System Capability Integration
  The lifecycle of many grid systems is far longer than the typical IT system lifecycle. Thus many legacy systems that do not support modern networking and operating systems are critical components of the grid network. Implementation of cybersecurity capabilities that affect these systems must be configured in a manner that does not impact the reliable operation of these critical systems and should be evaluated as part of any architecture or technology changes.

The end goal of this strategy is to develop an enhanced cybersecurity service layer architected in a manner that can be scaled to protect a wide-scale routable grid network hosting multiple systems. Enhancing the current state to support this direction requires a series of coordinated infrastructure initiatives. The following cybersecurity initiatives are in scope for our grid cybersecurity enhancement efforts:

- Secure administration environments
- Device access controls
- User access controls
- Advanced malware protections
- Vulnerability management
- Data encryption services
- System monitoring services

These initiatives must aim to both rectify cybersecurity deficiencies in current system architectures as well as develop a scalable architecture to support future grid applications.

Secure Administration Environments

Privileged credentials are the primary target of cybersecurity adversaries. Loss of control of these accounts can result in catastrophic system failure and prolonged service outage. Attacks which compromise these accounts are most commonly perpetrated by either privilege escalation attacks or malicious insiders. The purpose of designing secure administration environments is to prevent and deter both of these threats.

Malicious insiders are primarily deterred by implementing strong nonrepudiation controls. This effort will extend strong multifactor authentication from the control network across all grid systems for interactive user access. Additionally, all shared accounts and service accounts (accounts without a person's name) will be managed by a password vaulting system requiring users to authenticate with their multifactor token prior to granting access to the account. This ensures attribution of all system activity to a user ID and ensures that malicious insiders will know their activity is being logged.
The other common threat vectors previously mentioned are privilege escalation attacks. These attacks initially occur when a lower tiered system, such as a workstation or Human Machine Interface, is compromised with a virus that has taken full control over that particular machine. Part of the implementation of a secure administration environment is to minimize network account privileges to minimum required and implement access tiers to minimize the potential loss of control from any one system or account. This will require the implementation of additional security monitoring systems and access management applications to segment and monitor access without hindering operational productivity.

Device Access Controls

A fundamental cybersecurity control is profiling, authenticating, and monitoring devices connected to the network. Forcing an attacker to launch an attack from a compromised SCE controlled device is far easier to defend against than a device designed by an attacker. Additionally, IP connected devices outside of physically secure buildings such as cameras or control systems in the yard can be impersonated and their connections used to launch an attack. This effort will implement central network access control systems to allow authorized devices to connect to the network and provide an automated inventory of all devices. This system will be tuned to operate in a monitor-alert mode for critical control systems and automated protection control for non-critical systems.
In the event network access control is successfully circumvented, this effort also aims to deploy network fingerprinting technology to develop a baseline profile of a system's behavior and alert when that profile changes. For example, if a camera is profiled as a system that streams video and suddenly it starts trying to make remote access connections to systems, an alert will be generated for critical systems and an automated response for noncritical systems.

User Access Controls

This effort will extend multifactor authentication to all end-user interactive access from a centrally managed set of systems. The access control systems will need to have components extended into each of the grid system networks so that they may be centrally managed while still maintaining their system autonomy in the event of a network outage. This will simplify monitoring and provisioning user access as all access logs will be fed into an event monitoring and analytics system.

This effort will also include implementation of least privilege to ensure grid system users do not have access to systems outside their area of responsibility. This requires integration of user access authorizations with provisioning system access. This is achieved using a cross-domain solution between the administrative networks where the identity management systems reside and the access control systems on the grid network. This system will also be in-scope for modification to accommodate centralization of access management.

Advanced Malware Protections

Current grid system networks primarily employ a blacklisting strategy to protect against malware. Blacklisting strategies are only able to detect known malware. As exhibited in both the Stuxnet and Black Energy attacks on critical infrastructure, malware is highly likely to be customized to avoid detection by blacklisting systems. Given the nature of grid systems' mostly static application configuration compared to business networks, they are ideal for taking an application whitelisting approach. This authorizes a specific set of applications and processes to run on a given system and prevents all other applications or code from executing. This effort will implement this approach ubiquitously across grid system networks where feasible.

In the event that the application whitelisting system is defeated, behavior analysis detection systems will be implemented at both the system and network levels. This type of system analyzes the behavior of zero-day software to detect if it employs techniques common to cyber-attack. The system can then be tuned to either stop a piece of malware and/or alert on its detection. This will occur in tandem (not in-line) at the firewalls as all files pass through it and locally at the system level. Upon confirmation of malware detection, the firewalls and systems can automatically be triggered to block the malware from executing or traversing the network.

Vulnerability Management

Since the beginning of software development, there have been mistakes made in code or security control oversights that result in a system being vulnerable to a known attack logged in a public vulnerability database. A vulnerability management system (VMS) is critical to tracking known vulnerabilities and facilitating remediation. This effort will deploy new vulnerability scanning appliances to provide ubiquitous coverage of all grid networks.

Data Encryption Services

Grid networks have traditionally employed proprietary communications protocols to manage devices. This risk was traditionally accepted because grid systems were isolated and cyber-attack was not as common or as much of a risk. Given the changing risk landscape, grid network communication protocols, such a routable GOOSE and DNP, are beginning to adopt authenticated encryption into their standards. To support the use of secure communications protocols this effort will implement an encryption key management system, public key infrastructure, and integrate secure communications protocols on critical grid systems. This will greatly reduce the risk of a spoofed control message that could result in the misoperation of a system.

System Monitoring Services

Monitoring of grid system audit logs is a critical cybersecurity function required to support automated protection schemes, incident response coordination, and centralized system monitoring activities. SCE grid systems employ a number of disparate security information and event management (SIEM) systems that provide a disjointed view of cybersecurity activity on the grid. This decentralizes log monitoring and hinders detection of coordinated attacks. Integration of the disparate log monitoring systems into a centrally aggregated system is critical to achieving coordinated cybersecurity response and monitoring. Additionally, integration into SIEM will enhance compliance reporting capability as system operations event data will be centralized into a single system.

Centralizing log management and monitoring to a unified SIEM provides a great deal of data that needs to be filtered and analyzed to generate true positive alerts. This will be achieved by the implementation of log correlation to alert upon a set of rules created by cybersecurity monitoring teams. Furthermore, the log data can be fed into a system analytics platform to perform advanced log search as well as behavior baselining. This is the critical set of systems that take the data from all of the other cybersecurity systems to facilitate coordinated response.

VI. Metrics Update

The metrics presented in this section quantitatively asses the progress in implementing Smart Grid-related policy goals in California, namely those enumerated in SB 17 (codified at Public Utilities Code Section 8360). These metrics, which were adopted by D.12-01-025, will provide the Commission with information to assist in the production of its annual report to the Legislature, as required under Public Utilities Code Section 8367. The adopted metrics are broken into four categories:

1. Customer/AMI Metrics;
2. Plug-In Electric Vehicles Metrics;
3. Storage Metrics; and
4. Grid Operations Metrics.

A. Customer Metrics/ AMI Metrics

1. Number of advanced meter malfunctions where customer electric service is disrupted, and the percentage this number represents of the total of installed advanced meters.

Metric - Meter Malfunctions	Total	Percent
Number of Advanced Meter Malfunctions Interrupting Customer Service	≤3	0.00%

An AMI meter failure resulting in a disruption of customer electric service would occur if there were a malfunction in the remote service switch (RSS) or other internal catastrophic failure. During the reporting period there were ≤ 3 instances of an integrated service switch malfunction or other unplanned meter initiated customer interruptions. This metric does not include AMI meter malfunctions that do not result in service disruptions. As of June 30, 2017, SCE had installed 4,691,574 AMI meters with remote service switch capabilities.

2. Load impact in MW of peak load reduction from the summer peak and from winter peak due to smart grid-enabled, utility administered demand response (DR) programs (in total and by customer class).

Metric - Smart Grid Enabled DR	Customer Class	Load Impact Summer Peak (MW)	Load Impact Winter Peak (MW)
Load impact from smart-grid enabled, utility administered demand response programs	Residential	15.8	N/A
	C&I < 200 kW	N/A	N/A
	C&I > 200 kW	N/A	N/A
	Ag & Pumping	N/A	N/A
	Total	15.8	N/A

During the reporting period, the average residential programmable communicating thermostat (PCT) customer delivered a .49 kW load impact, resulting in a 15.8 MW aggregate reduction.[33]

[33] PCT is SmartConnect enabled communicating directly with the thermostat. The other programs do not have direct communication and utilize interval data.

3. Percentage of demand response enabled by AutoDR (Automated Demand Response) in each individual DR impact program.

Metric - % Auto DR	Price Responsive Program	Percent
Percentage of demand response enabled by AutoDR by individual DR impact program	AMP	8.0%
	CBP	8.4%
	CPP	10.8%
	DBP	27.3%
	DRAM	N/A

SCE's demand response programs with AutoDR capabilities included the Aggregator Managed Portfolio (AMP), Capacity Bidding Program (CBP), Critical Peak Pricing (CPP), Demand Bidding Program (DBP), and the Demand Response Auction Mechanism (DRAM). Based upon *ex post* load impacts for these programs, excluding DRAM, AutoDR load impact accounts for approximately 40 MW.

This table shows the AutoDR average estimated ex post load impacts relative to each program's aggregate ex post load impacts. Ex post load impacts were estimated from regression analysis of customer-level hourly load data according to the Demand Response Load Impact Protocols (D.08-04-050). These results reflect the demand reductions delivered during historical events, based on the conditions that were in effect during that time.

4. The number and percentage of utility-owned advanced meters with consumer devices with HAN or comparable consumer energy monitoring or measurement devices registered with the utility (by customer class, CARE status, and climate zone)

Metric - HAN Registered Devices	Total	Percent
The number of utility-owned advanced meters with consumer devices with HAN or comparable consumer energy monitoring or measurement devices registered with the utility (by customer class, CARE, and climate zone, to extent available)	2,138	0%

As of June 30, 2017, SCE had successfully registered 2,138 customer-owned HAN devices that remained provisioned to smart meters. This number includes both customer owned HAN devices, as well as those devices that remained provisioned to smart meters as part of SCE conducted HAN pilots in proceeding years.

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.

Note that widespread adoption of consumer HAN devices has not developed as expected due to delays with Smart Energy Profile 2.0 (no certified products as of this update), little interest to consumers for purchasing devices that provide energy consumption data, and alternative internet and home automation thermostats and other devices that provide remote access and control of electric loads. SCE expects organic growth of consumer HAN devices to be low and has seen an average of 30 new customer purchased HAN devices provisioned to smart meters each month.

5. Number and percentage of customers that are on a time-variant or dynamic pricing tariff (by type of tariff, by customer class, by CARE status, and by climate zone).

Customer Class	Program	CARE	Baseline Region 5	6	8	9	10	13	14	15	16	17	Subtotal	Total	Number of Residential Accounts: 4,383,643
Residential	CPP	CARE	-	-	-	-	-	-	-	-	-	-	-		Percentage of CPP Accounts:
		Non-CARE	-	1	2	-	-	-	-	-	-	-	3	3	0.00%
	TOU	CARE	1	803	1,460	1,225	1,933	739	1,259	482	107	-	8,009		Percentage of TOU Accounts:
		Non-CARE	13	12,307	11,398	10,151	9,707	1,161	2,582	2,004	942	-	50,265	58,274	1.33%
	PTR	CARE	-	219	529	835	1,227	143	297	143	31	-	3,424		Percentage of PTR Accounts:
		Non-CARE	1	4,695	8,879	8,459	6,900	523	974	1,433	489	-	32,353	35,777	0.82%
	EV	CARE	-	-	-	-	-	-	-	-	-	-	-		Percentage of EV Accounts:
		Non-CARE	-	277	204	323	59	1	15	12	19	-	910	910	0.02%

Customer Class	Program	CARE	Baseline Region 5	6	8	9	10	13	14	15	16	17	Subtotal	Total	Number of C&I >200 kW Accounts: 11,611
C&I >200 kW	CPP	CARE	-	394	740	522	587	46	88	43	34	-	2,454		Percentage of CPP Accounts:
		Non-CARE	-	3	32	20	17	1	1	-	-	-	74	2,528	21.77%
	TOU	CARE	-	395	743	524	588	46	88	43	34	-	2,461		Percentage of TOU Accounts:
		Non-CARE	4	1,647	2,514	1,994	1,890	300	468	240	88	5	9,150	11,611	100.00%
	RTP	CARE	-	-	-	-	-	-	-	-	-	-	-		Percentage of RTP Accounts:
		Non-CARE	-	22	43	26	25	1	5	2	4	-	128	128	1.10%
	EV	CARE	-	-	-	-	-	-	-	-	-	-	-		Percentage of EV Accounts:
		Non-CARE	-	-	-	-	-	-	-	-	-	-	-	-	0.00%

Customer Class	Program	CARE	Baseline Region 5	6	8	9	10	13	14	15	16	17	Subtotal	Total	Number of C&I <200 kW Accounts: 606,405
C&I <200 kW	CPP	CARE	-	-	-	-	-	-	-	-	-	-	-		Percentage of CPP Accounts:
		Non-CARE	-	104	174	149	154	28	48	12	14	-	683	683	0.11%
	TOU	CARE	-	34	29	47	22	5	9	2	2	-	150		Percentage of TOU Accounts:
		Non-CARE	238	130,405	150,359	134,300	99,869	26,854	31,410	19,846	12,508	-	605,789	605,939	99.92%
	RTP	CARE	-	-	-	-	-	-	-	-	-	-	-		Percentage of RTP Accounts:
		Non-CARE	-	-	-	-	-	-	-	-	-	-	-	-	0.00%
	EV	CARE	-	-	-	-	-	-	-	-	-	-	-		Percentage of EV Accounts:
		Non-CARE	-	52	25	26	30	4	7	15	2	-	161	161	0.03%

Customer Class	Program	CARE	Baseline Region 5	6	8	9	10	13	14	15	16	17	Subtotal	Total	Number ofAgricultural & Pumping Accounts 25,344
Agricultural & Pumping	CPP	CARE	-	-	-	-	-	-	-	-	-	-	-		Percentage of CPP Accounts:
		Non-CARE	-	4	10	4	8	8	9	2	-	-	45	45	0.18%
	TOU	CARE	-	-	-	-	-	-	-	-	-	-	-		Percentage of TOU Accounts:
		Non-CARE	64	2,305	845	2,561	2,517	12,844	1,969	763	1,453	-	25,321	25,321	99.91%
	RTP	CARE	-	-	-	-	-	-	-	-	-	-	-		Percentage of RTP Accounts:
		Non-CARE	-	5	3	1	-	1	3	-	4	-	17	17	0.07%

During the reporting period SCE discontinued its Peak Time Rebate (PTR) and its PTR-Enabling Technologies (PTR-ET) programs. PTR-ET-Direct Load Control is the only remaining PTR option.

6. Number and percentage of escalated customer complaints related to (1) the accuracy, functioning, or installation of advanced meters or (2) the functioning of a utility-administered Home Area Network with registered consumer devices.

Metric - Customer Complaints	Complaint Type	Total	Percent
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	410	8.25%
	Meter Installation	0	0.0%
	Meter Functioning	84	1.69%
	HAN	0	0%

To calculate the percentages, SCE received a total of 4,928 escalated complaints during the period July 1, 2016 through June 30, 2017. SCE defines the types of customer complaints measured by this metrics 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 Edison 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 *(NEM customers who question bill accuracy due to the meter – counted above in Meter Accuracy)*, and customer deployment opt-out requests.

7. The number and percentage of advanced meters replaced before the end of their expected useful life during the course of one year, reported annually, with an explanation for the replacement.

Metric - Meter Replacement	Total	Percent
Number of utility-owned advanced meters replaced annually before the end of their expected useful life	11,909	0.234%

Metric - Meter Replacement by Technology	Total	Percent
Hardware/Component Failure	10,881	0.214%
Firmware Related Failure	457	0.009%
Environmental Failure	224	0.004%
Communication Failure	347	0.007%

This metric includes the number of Advanced Metering Infrastructure (AMI) meters that were replaced after having been successfully installed during the three-year reporting period. The meter failure percentage is less than SCE's Edison SmartConnect™ business case assumption, as approved in D.08-09-039. The majority of AMI meters replaced before the end of their expected useful life were due to problems with the meter's Operating System, Random Access Memory, Data Flash or liquid crystal display failures. These predominant error types are consistent with previous year results. As of June 30, 2017, SCE had installed 5,073,971 AMI meters.

8. Number and percentage of advanced meters field tested at the request of customers pursuant to utility tariffs providing for such field tests, and the number of advanced meters tested measuring usage outside the Commission-mandated accuracy bands.

Metric - Meter Field Tests	Total	Percent
Number of advanced meter field tests performed at the request of customers pursuant to utility tariffs providing for such field tests	2,284	0.04%
Number of advanced meters tested measuring usage outside the Commission-mandated accuracy bands.	46	0.00%

This metric includes the number of field tests performed by SCE personnel on Advanced Metering Infrastructure (AMI) meters at the customer's request pursuant to SCE's tariffs (number of customer request tests completed 2,284), and the number of AMI meters tested that measured usage outside of the Commission-mandated accuracy bands for the reporting period (outside of accuracy bands 46). A meter that is not registering or exhibits variable accuracy is also considered outside accuracy bands and, as such, included in the total. As of June 30, 2017, SCE had installed 5,073,971 AMI meters.

9. Number and percentage of customers using a utility web-based portal to access energy usage information or to enroll in utility energy information programs or who have authorized the utility to provide a third-party with energy usage data.

Metric - Usage Info	Applicable Customer Class	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	Unique Customers with Access to Interval Usage Data	2,530,510	49.2%
	Unique Customers that have Accessed their Interval Usage Data	530,101	29.7%
	Customers Enrolled in Energy Information Programs	666,047	2.9%

This metric reports the number of customers that have enrolled in SCE's MyAccount and have access to their interval usage data through SCE's website, and the number of customers who accessed their interval usage data during the Reporting Period. In addition, this metric reports customers enrolled in SCE's Budget Assistant Program, which provides customers with automated proactive performance notifications based on a preset monthly spending goal. This metric excludes customers accessing usage information through non-utility portals, and also excludes customer accessing cumulative usage information. As of June 30, 2017, there were 5,114,775 customers with an Edison SmartConnect meter.

10. Various SmartMeter related information.[34]

Metric - SmartMeters	Total
Amount of SmartMeters installed	69,852
Amount of SmartMeters activated	69,095
Number of Opt-Outs	757
Amount of NON-SmartMeters manually read Amount of SmartMeters manually read	43,717 1,638

B. Plug-in Electric Vehicle Metrics

1. Number of customers enrolled in time-variant electric vehicles tariffs.

SCE offers three time-variant electric vehicle tariffs with the following enrollment as of June 30, 2017:

<table>
<tr><th>Metric - PEV Tariff Enrollment</th><th colspan="2">Residential</th><th colspan="2">Commercial</th></tr>
<tr><td rowspan="4">Number of customers enrolled in time-variant electric vehicles tariffs</td><td rowspan="2">TOU-EV-1</td><td rowspan="2">913</td><td>TOU-EV-3-A</td><td>32</td></tr>
<tr><td>TOU-EV-3-B</td><td>8</td></tr>
<tr><td></td><td></td><td>TOU-EV-4</td><td>120</td></tr>
<tr><td></td><td></td><td>TOU-EV-6</td><td>1</td></tr>
</table>

34 Metric requested by CPUC Energy Division in August 15, 2017 email.

TOU-EV-1 is available to residential customers. TOU-EV-3 (A and B), and TOU-EV-4 and TOU-EV-6 are only available for non-residential customers charging electric vehicles on a single dedicated meter. TOU-EV-3 (A and B) is available to customers whose monthly maximum demand is 20 kW or less while TOU-EV-4 is available to customers whose monthly maximum demand is above 20 kW, but does not exceed 500 kW. TOU-EV-6 has two different voltage ranges that service can be metered and delivered to. These voltage ranges are 2kV to 50kV and above 50kV.

C. Storage Metrics

1. MW and MWh per year of utility-owned or operated energy storage interconnected at the transmission or distribution system level. As measured at the storage device electricity output terminals.

Metric - Energy Storage	# of Facilities	Total MWs	Total MWhs/yr
MW and MWh per year of utility-owned or operated energy storage interconnected at the transmission or distribution system level. As measured at the storage device electricity output terminals	1pumped stored hydro	200 MWs pump load -177 MW's generation	200,000 MWhs/yr

As of July 30, 2017, SCE's Eastwood power station – a pumped storage hydro facility located within the broader Big Creek complex – represents the largest energy storage facility interconnected to either SCE's transmission or distribution system. This pumped storage hydro facility has a capacity of approximately 200 MWs and produces about 200,000 MWh per year.[35]

[35] 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 for each year starting on July 1, 2011 through the latest year that this information is available.[36]

Metric - SAIDI	Year	Major Events Included	Major Events Excluded
System-wide total number of minutes per year of sustained outage per customer served as reflected by SAIDI	2002	52.29	44.95
	2003	89.26	53.37
	2004	74.93	55.30
	2005	92.26	72.57
	2006	134.39	87.21
	2007	163.15	95.89
	2008	107.48	95.43
	2009	119.18	90.70
	2010	141.20	100.25
	2011	223.42	107.98
	2012	100.45	98.23
	2013	106.17	88.08
	2014	106.83	96.94
	2015	148.90	114.96
	2016	125.974	102.99

36 Values provide for SAIDI represent a July-to-June snapshot and should not be confused with the values provided by SCE within its Annual System Reliability Report which is done on a calendar year basis.

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 for each year starting on July 1, 2011 through the latest year that this information is available.[37]

Metric - SAIFI	Year	Major Events Included	Major Events Excluded
How often system-wide average customer interrupted in reporting year as reflected by SAIFI	2002	1.27	1.05
	2003	1.39	1.11
	2004	1.34	1.15
	2005	1.53	1.33
	2006	1.01	0.82
	2007	1.16	0.95
	2008	1.02	0.96
	2009	0.87	0.76
	2010	1.06	0.86
	2011	1.01	0.89
	2012	0.90	0.89
	2013	0.92	0.83
	2014	0.90	0.86
	2015	1.12	0.99
	2016	1.061	0.95

[37] Values provided for SAIFI represent a July-to-June snapshot and should not be confused with the values provided by SCE within its Annual System Reliability Report pursuant to D.96-09-045.

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 for each year starting on July 1, 2011 through the latest year that this information is available.[38]

Metric - MAIFI	Year	Major Events Included	Major Events Excluded
Number of momentary outages per customer system-wide per year, as reflected by MAIFI, major events included and excluded	2002	1.15	1.09
	2003	1.43	1.15
	2004	1.21	1.05
	2005	1.47	1.23
	2006	1.78	1.41
	2007	1.90	1.60
	2008	1.50	1.38
	2009	1.55	1.38
	2010	1.62	1.38
	2011	1.49	1.33
	2012	1.31	1.29
	2013	1.29	1.19
	2014	1.28	1.23
	2015	1.65	1.43
	2016	1.60	1.40

[38] Values provided for MAIFI represent a July-to-June snapshot and should not be confused with the values provided by SCE within its Annual System Reliability Report pursuant to D.96-09-045.

4. Number and percentage of customers per year and circuits per year experiencing greater than 12 sustained outages for each year starting on July 1, 2011 through the latest year that this information is available.

Metric	Year	Customers/yr	Circuits/yr
Number of customers per year and circuits per year, experiencing greater than 12 sustained outages	2002	1,896	4
	2003	7,212	19
	2004	12,269	26
	2005	3,123	13
	2006	93	2
	2007	741	3
	2008	1,473	16
	2009	435	8
	2010	167	5
	2011	1,243	7
	2012	11,625	2
	2013	7	1
	2014	1,083	7
	2015	2,209	10
	2016	483	8

Metric	Year	Customers/yr	Circuits/yr
Percentage of customers per year and circuits per year, experiencing greater than 12 sustained outages	2002	0.04%	N/A
	2003	0.16%	N/A
	2004	0.26%	N/A
	2005	0.07%	N/A
	2006	0.00%	N/A
	2007	0.02%	N/A
	2008	0.03%	N/A
	2009	0.01%	N/A
	2010	0.00%	N/A
	2011	0.03%	N/A
	2012	0.23%	N/A
	2013	0.00%	N/A
	2014	0.02%	N/A
	2015	0.04%	0.22%
	2016	0.01%	0.18%

5. System load factor and load factor by customer class for each year starting on July 1, 2011 through the latest year that this information is available.

Metric - Load Factor	Customer Class	2015 Load Factor
System load factor and load factor by customer class	Residential	34%
	C&I < 200 kW	49%
	C&I > 200 kW	66%
	Ag & Pumping	63%
	System	52%

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 55,000 customers, representing all classes of Edison customers, with about 35,000 data points per sampled customer. Load factors by customer class often reside outside of the 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 distributed generation facilities.

Metric - DG Number & Capacity	Program	# of Facilities	Total Capacity (MW)
Number of and total nameplate capacity of customer-owned or operated, utility grid-connected distributed generation facilities * Data are as of 6/30/2017	CREST/WATER*	92	117.2
	Re-MAT*	12	21.2
	SPVP (IPP)*	27	50.2
	SPVP (UOG)*	25	67.5
	CSI	53,364	762.4
	SGIP	299	29.6
	TOTAL	**53,819**	**1048.1**

SCE offers two state-mandated incentive programs, the California Solar Initiative (CSI) and the Self-Generation Incentive Program (SGIP), for customer side of the meter DG, also referred to as "onsite generation" or "self-generation." The CSI rebate program ended last year with only 360 projects at an additional 68 MW in capacity installed as part of the incentive program within the reporting period of July 2015 to June 2016. Since July 2011, just over 49,000 CSI systems have been installed with a capacity of about 588 MW in conjunction with SCE administered incentive programs as of the end of the Reporting Period. CSI Residential Incentives were depleted in Q1 2014, while SGIP increased due to the addition of Advanced Energy Storage technology (Batteries that can pair with any existing SGIP technology (solar, fuel cells, wind, etc.). While CSI installations continued at a very heavy pace during the Reporting Period, almost none of them were part of an incentive program.

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 Renewable Market Adjusting Tariff (Re-MAT) and BioMAT programs which executes a power purchase agreement where SCE will pay for either the total or excess energy a customer generates through facilities not greater than 3 MW. The Re-MAT program accommodates all eligible renewable technologies up to a total of 39.9 MW as of August 2017. The BioMAT program accommodates only bioenergy renewable technologies up to a total of 114.5 MW as of August 2017. SCE's Solar Photovoltaic Program (SVPV) allows SCE, over a five year period, to build and operate no less than 91 MW of utility-owned solar photovoltaic capacity and to execute contracts up to 125 MW for generation from similar facilities owned and maintained by independent power producers (IPPs) through a competitive solicitation process.[39] This program is applicable to primarily rooftop solar PV facilities with a small portion of ground mounted facilities.

[39] The RAM component of SPVP involves procuring 284 MW DC of SPVP through RAM (256 MW AC). This 256 MW AC is subject to RAM protocols and practices. Please see D.13-05-033, Attachment 1.

7. Total electricity deliveries from customer-owned or operated, grid-connected distributed generation facilities, reported by month and by ISO sub-Load Aggregation Point.

Metric - DG Electric Deliveries	Program	GWhs
Total annual electricity deliveries from customer-owned or operated, utility grid-connected DG facilities * Data are as available for period 7/1/2011 – 4/30/2017	CREST/WATER*	833.6
	Re-MAT*	39.6
	SPVP (IPP)*	259.7
	SPVP (UOG)*	605.3
	NSC	92.2
	TOTAL	**1,830.4**

Facilities brought online under SCE's CREST/WATER, RE-MAT, SPVP, and net surplus compensation (NSC) programs together produced nearly 1.8 billion kWh. This value captures only electric deliveries to the grid; it does not represent the total energy production of distributed generators in SCE's service territory. All of the energy provided by distributed generators in either the CSI or SGIP programs is "customer side of the meter," meaning that it first serves onsite customer load requirements before feeding any excess energy onto the distribution system. Customers matching this load profile have the option to subscribe under SCE's NSC rate, which pays customers who produce more kilowatt hours than they consume in a 12-month period.

8. Number and percentage of distribution circuits equipped with automation or remote 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 - Reporting Start Date - July 2012	3,500	4,600	76%

This metric indicates that 76 percent of circuits have at least a primitive deployment of SCADA allowing for basic remote control of certain installed equipment and rudimentary equipment status through SCE's existing DMS system to protect critical distribution infrastructure, restore outages, and minimize customer minutes interrupted.

Appendix 1

Smart Grid Customer Engagement by Initiative

Smart Grid Engagement by Initiative. As requested by CPUC staff in its March 1, 2012 Smart Grid Workshop Report, the information presented in this appendix provides the customer engagement elements (i.e., project description, target audience, sample message, source of message, current road blocks and strategies to overcome roadblocks) for the following initiatives:

Customer Premise Devices

A. Near Real-Time Usage (HAN)

Online Tools

B. Integrated Audit Tool

C. Web Presentment Tools

D. Budget Assistant

E. Green Button Download My Data

F. Green Button Connect My Data

G. Mobile-Optimized Outage Center

Rates and Programs

H. Save Power Day (PTR)

I. PEV Time-of-Use Rates

J. Residential TOU Rates

Customer Premise Devices

A. Near Real-Time Usage (HAN)

Project Description	ME&O to educate customers on their near real-time usage data which can display the customer's current usage on a registered display device.
Target Audience	Residential and small/medium non-residential customers with demands less than 200 kW.
Sample Message	Beginning in 2010, SCE developed messaging to market Home Area Network (HAN) devices and their potential benefits to customers through a variety of pilot and production programs. These included an In-Home Display (IHD) field trial, Interim HAN Solution and Real Time Cost Pilots targeting a larger population with IHDs, and partnerships with ADT and DirecTV to provide HAN devices to SCE customers. SCE also updated SCE.com with information to educate customers about HAN devices and provide an automated way for them to register HAN devices purchased at retail. The information provided on the HAN webpage at SCE.com and the automated registration via SCE.com's My Account, has been in place and operational since 2013. The automated registration capability virtually provides any residential customer the ability to purchase and register a HAN device with their smart meter.
Source of Message	Utility and third parties that leverage the data for energy service offerings.
Current Customer Engagement Road Block(s)	Although efforts have been made to educate customers about HAN devices and potential benefits, a robust retail market of HAN devices has not developed as anticipated, results from SCE pilots and programs haven't shown long term benefits, and customers haven't seen enough value from HAN devices to justify purchasing them. In addition, a variety of internet connected thermostats and home automation systems have gained traction in the consumer marketplace as an alternative to HAN devices.
Strategy to Overcome Roadblocks	Based on consumer needs and the evolving marketplace, HAN devices have been superseded by internet connected home automation devices such as smart thermostats. SCE's strategy has been to support the needs of the marketplace and develop

	programs that utilize devices being purchased and installed by our customers. However, SCE will continue to support customers who purchase HAN devices and connect them to their smart meter.

Online Tools

B. Enhanced Energy Advisor Tool (EEAT)

Project Description	Our Enhanced Energy Advisor Tool (EEAT) is a "do-it-yourself" online survey where customers can complete a quick 5 minute survey about their home. The survey asks customers to share characteristics about their homes structure, heating & cooling, appliances and other installed equipment. Once the survey is complete and a customer is logged in, customers can: • View their historical Energy Use and compare their usage to similar neighbors • Receive helpful "Ways to Save" or customized tips based on their survey input that will help lower energy consumption. • Create a customized plan for saving energy In 2016, SCE added a single sign on feature that allow customers who are logged into SCE's My account to seamlessly link over to EEAT without the having to sign in twice.
Target Audience	Residential and business customers.
Sample Message	Answer some questions to get an analysis of your energy use, along with customized recommendations for how to save and where to start. Then, let the tool work for you by tracking your progress, updating your actions and seeing the savings.
Source of Message	Utility
Current Customer Engagement Road Block(s)	• A workpaper is not developed, in order to claim savings for activity that occurs on the site (ETA 2018/19).
Strategy to Overcome Roadblocks	• Develop marketing initiatives to drive customer participation. Once participation reaches 30,000 SCE can start developing a workpaper.

C. Web Presentment Tools

Project Description	ME&O to educate customers about online tools that provide interval energy usage and billing data that enable customers to make better energy management decisions. Online tools include: estimated bill-to-date, projected next bill, and interval data charts. See SCE Advice 2693-E[40] for more information about these tools.
Target Audience	Residential and small/medium non-residential customers with demands less than 200 kW who have a smart meter that is measuring interval data for billing purposes.
Sample Message	"Online tools can help you take control of your energy bills."
Source of Message	Utility
Current Customer Engagement Road Block(s)	• Customers need internet access to take full advantage of the tools. • Low customer adoption rate.
Strategy to Overcome Roadblocks	• Customers who do not have internet access can obtain information on their interval energy usage and billing data through the call center. • Bundle tools with other relevant products, rates and services, such as TOU rates. • Integrate relevant information into appropriate marketing materials.

[40] Advice 2693-E is pending disposition from the Commission.

D. Budget Assistant

Project Description	ME&O to educate customers regarding SCE's Budget Assistant tool which allows customers to easily monitor energy usage and costs. ME&O will be used to educate, inform and enroll customers by communicating that Budget Assistant helps eliminate end of the month bill surprises by providing alert notifications. See SCE Advice 2693-E for more information about this tool.
Target Audience	Most residential and small/medium non-residential customers with demands less than 200 kW.
Sample Message	"Manage and control your electricity costs when you set a monthly spending goal and get updated with trigger based, mid-month billing cycle or weekly notifications via email, text or voice message – eliminating any end-of-the-month bill surprises."
Source of Message	Utility
Current Customer Engagement Road Block(s)	• Typically and opt-in program, therefore customers must enroll in the program to receive alerts. • Lack of customer awareness of alerts due to no dedicated marketing. • Same messaging for all customers (rates).
Strategy to Overcome Roadblocks	• Bundle tool and cross-promote with other relevant products, rates and services. • Default customers onto the program. • Develop more meaningful messaging and content for different customers (rate types).

E. Green Button Download My Data

Project Description	Green Button is a White House initiative to allow customers greater access to their usage data via a "Green Button" on sce.com. Green Button will allow customers to download up to thirteen months of historical interval usage data in a data format that is standard across utilities.
Target Audience	All Customers
Sample Message	Green Button icon and "Download My Data" message provided on SCE.com.
Source of Message	The messaging source is third parties that leverage Green Button data for their energy service offerings.
Current Customer Engagement Road Block(s)	SCE will provide the Green Button data, but does not market or offer any services that will use the Green Button data beyond providing the Green Button icon, Download My Data, or Connect My Data on SCE.com.
Strategy to Overcome Roadblocks	Third parties, CPUC, and IOUs should monitor national Green Button developments, continue discussions with the U.S. Department of Energy, and respond as appropriate.

F. Green Button Connect My Data

Project Description	SCE provides third parties access to individual customer's smart meter usage data via the utility's "backhaul" when authorized by the customer, and in a common data format consistent with the ongoing national Smart Grid standards efforts. The Customer Data Access, known as Green Button Connect, will leverage the Energy Service Provider Interface (ESPI) platform to transfer the data.
Target Audience	Green Button Connect is available for all customers.
Sample Message	SCE will provide 3rd Parties a unique URL during registration. This link will be sent to customers by their designated 3rd parties to streamline the customer authorization process. These third parties will market services to customers and develop messaging consistent with their energy service offerings.
Source of Message	Third parties that leverage Green Button Connect for their energy service offerings.
Current Customer Engagement Road Block(s)	The majority of engagement with customers regarding the use of this service will come from the third parties that offer energy management services that can leverage Green Button Connect. The Green Button Connect program was made available in November 2014.
Strategy to Overcome Roadblocks	Pursuant to D.13-09-025, SCE filed an Advice Letter providing key details about Green Button Connect My Data that leverages the ESPI platform.

G. Mobile-Optimized Outage Center

Project Description	This has now become operational as sce.com/outagecenter and is the hub for all outage information. Background: ME&O to educate customers on the mobile-optimized SCE Outage Center. Customers can view the status of outages and report outages on their smart phone or tablet. See SCE.com for more information.
Target Audience	All customers are now able to visit sce.com/outagecenter whether on desktop, tablet or mobile.
Sample Message	Historical Marketing Message: "We know you depend on your mobile phone to communicate and stay safe during an emergency. If you experience a power outage, use your phone's web connection to report outages and view outage locations as well as find out when your service may be restored. Visit sce.com/outage. You can also use this site to report street light outages and find or report current outages at any time." This message is no longer used.
Source of Message	Utility
Current Customer Engagement Road Block(s)	• There are no current roadblocks as this is the norm for online experiences.
Strategy to Overcome Roadblocks	• Customers without an internet connected device can continue to call to report an outage. • Integrate educational materials regarding this tool in appropriate marketing materials and sce.com.

Rates and Programs

H. Save Power Day (Peak Time Rebate)

<table>
<tr><td>Project Description</td><td>ME&O to educate customers on SCE's Peak Time Rebate Program (PTR) marketed as the Save Power Day (SPD) program. Customers choosing to participate need to enroll to qualify to receive program related incentives. Customer can choose to receive SPD event notifications through voice text, or email. When an SPD event is called, customers can choose to reduce electricity use between the hours of 2pm and 6pm in order to earn bill credits. The Save Power Day program is structured to provide customers with multiple enrollment and incentive options:

1. Base Program: Provides an incentive of $0.75 per kWh reduced during events (aka PTR).
2. Enhanced Program: Provides an incentive of $1.25 per kWh reduced during events for customers with a HAN device provisioned with their smart meter (aka PTR-ET).

Enhanced Program with Load Control: Provides an incentive of $1.25 per kWh reduced during events for customers with an eligible and enabled 3rd Party load control device (aka PTR-ET-DLC).

On December 9, 2015 SCE filed Advice Letter 3323-E to the commission requesting approval to discontinue PTR and PTR-ET in 2016 due to low per-customer savings, poor cost-effectiveness, and low dispatch flexibility. However, on April 1, 2016, SCE proposed, in its response to the ACR Directing Activities in Response to Natural Gas Leak at Aliso Canyon Storage and Seeking Comments, to delay the discontinuation of PTR and PTR-ET until 2017 to avoid risks associated with making system changes during the 2016 summer season and mitigate customer confusion or dissatisfaction by not giving adequate notice prior to summer. On June 9, 2016 the Commission issued D.16-06-029 adopting the proposed changes to decommission PTR and PTR-ET by summer of 2017. As of April 20, 2017, PTR and PTR-ET were discontinued.

SCE plans to retain the PTR-ET-DLC option going forward. In D.16-06-029, the Commission authorized SCE to pursue</td></tr>
</table>

	changes in 2017 that will enable the program to integrate into the CAISO wholesale market in 2018.
Target Audience	Residential customers with a smart meter that is measuring interval data for billing purposes and who purchase and install a qualifying thermostat.
Sample Message	With up to $125 in available bill credits, it has never been a better time to enroll your new or existing smart thermostat. If you are a joint customer of SCE and SoCalGas®, you'll get a $125 SCE bill credit when you successfully enroll through a qualified service provider. If you are our customer, but not a customer of SoCalGas, you'll receive a $75 SCE bill credit. A Wi-Fi smart thermostat may help reduce your electricity usage, and can potentially help you save on air conditioning (A/C) costs at home. Simply choose from a selection of qualified smart thermostats. Then, enroll in a qualified vendor's smart thermostat program that participates in our Save Power Days program. During Save Power Days events, your smart thermostat service provider may adjust the temperature and pre-cool your home – but you have the flexibility to adjust the temperature setting to help you stay comfortable. When you lower your A/C usage, you may be eligible for bill credits.
Source of Message	Utility/Authorized Smart Thermostat Service Providers (i.e., Nest, EnergyHub, Whiskerlabs)
Current Customer Engagement Road Block(s)	• Slow mass adoption rates of smart thermostats (caused by cost of thermostats and lack of program awareness)
Strategy to Overcome Roadblocks	• Continue to work with smart thermostat service providers to promote the program to new and existing thermostat owners • Continue offering a sign up rebate to help with the cost of the thermostat

I. PEV Time-of-Use Rates

Project Description	ME&O to educate customers on PEV rate options, environmental benefits, charging levels, and other aspects of PEVs. Materials encourage customers to contact the utility prior to taking delivery of a PEV which will better inform the customer and start the process for SCE to check the distribution infrastructure for safe and reliable charging. See SCE.com for more information about PEV TOU rates.
Target Audience	Residential and business customers who have shown interest in leasing or purchasing an electric vehicle or are interested in providing charging stations at their place of business.
Sample Message	Discover the potential savings of an EV. With the right rate plan, charging from 10 p.m. to 8 a.m. keeps costs down. Discover the potential savings of an EV. Our EV Rate Assistant helps you choose the right plan.
Source of Message	Utility
Current Customer Engagement Road Block(s)	• Customers do not think about contacting the utility prior to purchasing and/or taking delivery of their new PEV. • Dealers have some apprehension to introducing the role of the utility during the sales process.
Strategy to Overcome Roadblocks	• Conduct online advertising to generate awareness of electric vehicle rates. • Continue online EV Assessment Tool on SCE.com to guide visitors to website on appropriate content: EV rates, EV charging, EV benefits, EV tools and resources. • Continue "What's Your EV IQ?" banner ad campaign to inform customers about an EV's cost savings and environmental benefits, and seek to address range anxiety. Campaign aims to intrigue and engage people by challenging them with fun mini-quizzes, and provides an opportunity to inform them of EV benefits that could motivate them to consider driving an EV.

	• Developing business EV Rate Assistant Tool to allow business customers to evaluate their rate options available to serve transportation electrification charging equipment.

J. Residential TOU Rates

Project Description	Residential Time-of-Use rates provide customers with the ability to take more control over their energy costs. SCE currently offers several residential TOU rate plans. On July 3, 2015, the CPUC approved a decision on Residential Rate Reform (RROIR) which sets forth a glide path for restructuring the tiered rate plan and transitioning Residential customers to time differentiated rates. As part of that transition, SCE launched a TOU Opt-in Pilot on June 1, 2016 for 22k customers to test retention and behavior on various time-of-use rates. The pilot runs through Dec 31, 2017 and is testing impacts and reactions of three rates only available for the Pilot. In addition to the Opt-in Pilot, SCE has begun sending rate analyses via direct mail and e-mail to customers comparing their current Domestic rate costs to available TOU rates, along with information on how to enroll in those rates. Residential customers who have more than 12 months of interval data will receive a direct mail or email with information about rates, as well as a link to view what their potential savings or costs could be (based on their prior usage patterns) if they switched to a TOU rate. SCE will also be conducting a pilot with 400k residential customers that will default customers to TOU in Spring 2018. SCE will be testing a variety of communications to inform those customers so they can choose which rate is best for them.
Target Audience	Residential customers
Sample Message	Take more control of your electricity bill – new Time-of-Use rate plans offer different pricing during different times of the day/week providing you with the ability to better manage your energy costs.
Source of Message	SCE.com/My Account; targeted outreach campaigns; broad awareness campaigns; statewide communications.
Current Customer	• Information clutter • Low interest topic area • Savings require a behavior change in most cases

Engagement Road Block(s)	• Saving may not be significant enough to motivate change • Customers must take a more active role with managing their energy use
Strategy to Overcome Roadblocks	• Creative messaging • Creative engagement strategies • Improve CSRs Rate knowledge / literacy • Pilot testing • Targeted solicitations

Pilot and Demonstration Programs. In addition to the initiatives described above, SCE has launched a Customer Empowerment pilot. Generally, SCE will provide pilots to a limited target audience for a limited duration and SCE will not provide ME&O to its general customer population. However, pilots are expected to provide SCE with an improved assessment of potential messaging, customer engagement roadblocks, and potential strategies to overcome such roadblocks. Information regarding specific SCE Customer Empowerment efforts is provided below:

- **TOU Opt-in Pilot**. The TOU Opt-in Pilot was launched on June 1, 2016 an in effort to test a number of objectives in the pilot design to help inform 2019 TOU residential default. These objectives include but are not limited to the following:

    a. Assessing customer understanding /acceptance / engagement /satisfaction /retention with various TOU rate options

    b. Assessing the degree of hardship that might result from default TOU rates on senior households and economically vulnerable customers (and perhaps others) as directed by Public Utilities Code Section 745

    c. Assessing adoption rates for enabling technology for customer on TOU rates

    d. Assessing the effectiveness of education and outreach options

Appendix 2

Description of Baseline Regions

Map of Baseline Regions