BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of the California Energy Commission for Approval of Electric Program Investment Charge Proposed 2015 through 2017 Triennial Investment Plan.	))))	Application 14-04-034 (Filed April 29, 20014)
And Related Matters.	)))	Application 14-05-003 Application 14-05-004 Application 14-05-005

SOUTHERN CALIFORNIA EDISON COMPANY'S (U-338-E) ANNUAL REPORT ON THE STATUS OF THE ELECTRIC PROGRAM INVESTMENT CHARGE PROGRAM

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Dated: **February 28, 2017**

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I.

INTRODUCTION AND SUMMARY

In Ordering Paragraph 16 of Decision 12-05-037, the California Public Utilities Commission (CPUC or Commission) ordered Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and the California Energy Commission (CEC), collectively known as Electric Program Investment Charge (EPIC) Administrators, to file annual reports concerning the status of their respective EPIC programs; a copy is also to be served on all parties in the most recent EPIC proceedings; the most recent general rate cases of PG&E, SCE and SDG&E; and each successful and unsuccessful applicant for an EPIC funding award during the previous calendar year.

Subsequently, in D.13-11-025, Ordering Paragraph 22, the Commission required the EPIC Administrators to follow the outline contained in Attachment 5 when preparing the EPIC Annual Reports. In Ordering Paragraph 23 of the same Decision, the Commission required the

EPIC Administrators to provide the project information contained in Attachment 6 as an electronic spreadsheet.

Furthermore, in D.15-04-020, Ordering Paragraph 6, the Commission required the EPIC Administrators to identify specific Commission proceedings addressing issues related to each EPIC project in their annual EPIC reports. In Ordering Paragraph 24 of the same Decision, the Commission required the EPIC Administrators to identify the CEC project title and amount of IOU funding used for joint projects.

In compliance with the Ordering Paragraphs of D.12-05-037, D.13-11-025 and D.15-04-020, SCE respectfully files its annual report on the status of its EPIC activities for 2016. This is SCE's third annual report pertaining to its 2012-2014 EPIC Triennial Investment Plan (Application (A.) 12-11-004) after receiving CPUC approval on November 14, 2013. This is SCE's first annual report pertaining to its 2015-2017 EPIC Triennial Investment Plan (Application (A.) 14-05-005) after receiving CPUC approval on April 9, 2015.

Respectfully submitted,

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February 28, 2017

EPIC ADMINISTRATOR ANNUAL REPORT

Epic Administrator Annual Report

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1. Executive Summary

a) Overview of Programs/ Plan Highlights

2016 represented SCE's third full year of implementing program operations of its 2012 – 2014 Investment Plan Application[1] after receiving Commission approval on November 19, 2013,[2] and almost two full years of implementing program operations of its 2015 – 2017 Investment Plan Application[3] after receiving Commission approval on April 9, 2015.[4] SCE presents the highlights from its 2012 – 2014 Investment Plan and 2015 – 2017 Investment Plan separately below.

(1) 2012-2014 Investment Plan

For the period between January 1 and December 31, 2016, SCE expended a total of \$15,617,728 toward project costs and \$35,963[5] toward administrative costs for a grand total of \$15,581,765. SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC program amount to \$31,313,240. SCE committed \$37,755,476[6] toward projects and encumbered \$23,146,836 through executed purchase orders during this period.

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1 (A.)12-11-001.
2 D.13-11-025, OP8.
3 (A.) 14-05-005.
4 D.15-04-020, OP1.
5 Administrative cost was a credit of \$35,963 due to a contractual invoice that was incorrectly recorded to EPIC I in December 2015. Because the amount should have been recorded to EPIC II, a correction was made in January 2016 to reclassify the cost from EPIC I to EPIC II. In addition, effective January 1, 2016, all administrative costs were charged to EPIC II in order to release remaining EPIC I administrative funds for use by EPIC I projects. Thus, EPIC I did not incur any additional costs in 2016 to offset the credit of \$35,963.
6 SCE's committed funding for Total Projects and Program Administration amounted to \$37,389,267 and \$1,023,292, respectively. In-house labor overheads commitment, which is calculated by SCE's accounting system separately, amounted to \$970,686. Based on SCE's available funding of \$39,749,454, total EPIC contingency funding amounts to \$366,209.

SCE continued project execution activities toward the approved portfolio of sixteen projects; four of these projects were completed during the calendar year 2016. These four completed projects include 1) Enhanced Infrastructure Technology Report; 2) Submetering Enablement Demonstration; 3) Dynamic Line Rating; and 4) Distribution Planning Tool. In accordance with the Commission's directives,[7] SCE has completed final project reports for these four projects and included those completed in 2016 in the Appendix of this annual report.

(2) 2015-2017 Investment Plan

For the period between January 1 and December 31, 2016, SCE expended a total of $4,950,128 toward project costs and $770,601 toward administrative costs for a grand total of $5,720,729. SCE's cumulative expenses over the lifespan of its 2015 – 2017 EPIC program amount to $6,284,109. SCE committed $36,679,917[8] toward projects and encumbered $12,096,976 through executed purchase orders during this period.

SCE started project execution activities toward the approved portfolio of 13 projects after two projects were cancelled. The details of these cancellations are included in this Report. SCE also recently completed the Submetering Enablement Demonstration - Phase 2 project and per the Commission's directives, SCE has included a final report.

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[7] D.13-11-025, OP14.

[8] SCE's committed funding for Total Projects and Program Administration amounted to $33,335,689 and $3,565,100, respectively. In-house labor overheads commitment, which is calculated by SCE's accounting system separately, amounted to $1,331,583. Based on SCE's available funding of $41,694,600, total EPIC contingency funds amount to $3,462,228.

b) **Status of Programs**

(1) **2012-2014 Investment Plan**

As of December 31, 2016, SCE has expended $30,256,485 [9] on project costs. Table 1 below summarizes the current funding status of SCE's EPIC projects:

Table 1: 2012-2014 Triennial Investment Plan: 2016 Projects

1. Energy Resources Integration
• 4 Projects Funded • Total Funding Committed: $3,701,323
2. Grid Modernization and Optimization

• 5 Projects Funded
  o 1 Project Cancelled in Q2 2014[10]
  o 1 Project Completed in 2015[11]
• Total Funding Committed: $8,953,493

3. Customer Focused Products and Services
• 3 Projects Funded   o 1 Project Completed in 2015[12] • Total Funding Committed: $4,396,056
4. Cross-Cutting/Foundational Strategies and Technologies
• 4 Projects Funded   o 1 Project Completed in 2015[13] • Total Funding Committed: $20,338,395
Total Projects Funded: 16 Total Funding Committed: $37,389,267[14] *Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*

Table 2 below summarizes SCE's 2016 administrative expenses:

Table 2: 2012-2014 Triennial Investment Plan: 2016 Administration

• Program Administration	Total Funding Committed: $1,023,292 Total 2016 Cost: ($35,963) Total Cumulative Cost: $1,056,754

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9 SCE's cumulative project expenses amounted to $29,423,189 based on the project spreadsheet in Appendix A. SCE's accounting system calculates in-house labor overheads separately which amounted to $833,296. As a result, SCE expended a total of $30,256,485 on project costs.

10 SCE cancelled the Superconducting Transformer project in 2014. Please refer to the project's status update in Section 4 for additional details.

11 Portable End-to-End Test System.

12 Outage Management & Customer Voltage Data Analytics.

13 Cyber-Intrusion Auto-Response and Policy Management System.

14 For additional details regarding SCE's Committed Funds, please see the attached spreadsheet.

(2) 2015-2017 Investment Plan

As of December 31, 2016, SCE has expended $5,193,434[15] on project costs. Table 3 below summarizes the current funding status of SCE's EPIC projects:

Table 3: 2015-2017 Triennial Investment Plan: 2016 Projects

1. Energy Resources Integration
• 3 Projects Funded • Total Funding Committed: $414,524
2. Grid Modernization and Optimization
• 6 Projects Funded • Total Funding Committed: $12,149,762
3. Customer Focused Products and Services
• 3 Projects Funded • Total Funding Committed: $3,156,833
4. Cross-Cutting/Foundational Strategies and Technologies
• 1 Projects Funded • Total Funding Committed: $17,614,570
Total Projects Funded: 13 Total Funding Committed: $33,335,689[16] *Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*

Table 4 below summarizes SCE's 2016 administrative expenses:

Table 4: 2015-2017 Triennial Investment Plan: 2016 Administration

• Program Administration	Total Funding Committed: $3,565,100 Total 2016 Cost: $770,601 Total Cumulative Cost: $1,090,675

2. Introduction and Overview

a) Background on EPIC (General Description of EPIC)

The Commission established the EPIC Program to fund applied research and development, technology demonstration and deployment, and market facilitation programs to serve the interests of ratepayer benefits. Please refer to Decision (D.)12-05-037. This Decision

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[15] SCE's cumulative project expenses amounted to $5,009,808 based on the project spreadsheet in Appendix A. SCE's accounting system calculates in-house labor overheads separately, which amounted to $183,626. As a result, SCE expended a total of $5,193,434 on project costs.

[16] For additional details regarding SCE's Committed Funds, please see the attached spreadsheet.

further stipulates that the EPIC will continue through 2020[17] with an annual budget of $162 million.[18] Approximately 80% of the EPIC is administered by the CEC, and 20% is administered by the investor-owned utilities (IOUs). Additionally, 0.5% of the total EPIC budget, funds Commission oversight of the Program.[19] The IOUs were also limited to only the area of Technology Demonstration and Deployment (TD&D) activities.[20] SCE was allocated 41.1% of the budget and administrative activities.[21]

The Commission approved SCE's 2012-2014 Investment Plan[22] in D.13-11-025 on November 19, 2013. SCE submitted its 2015-2017 Investment Plan Application[23] on May 1, 2014 and the Commission approved the Application in D.15-04-020 on April 9, 2015. SCE is currently executing both of its 2012-2014 and its 2015-2017 EPIC Investment Plans.

b) EPIC Program Components

The Commission limited SCE's involvement in the first two EPIC cycles (2012-2014 and 2015-2017) to technology demonstration and deployment projects, per D.12-05-037. The Commission defines technology demonstration and deployment projects as installing and operating pre-commercial technologies or strategies at a scale sufficiently large in conditions sufficiently reflective of anticipated actual operating environments to enable appraisal of the operational and performance characteristics and the financial risks.[24]

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17 D.12-05-037, OP1.
18 D.12-05-037, OP7.
19 Id, OP5.
20 Id.
21 D.12-05-037, OP 7, as modified by D.12-07-001.
22 A.12-11-004.
23 A.14-05-005.
24 D.12-05-037, OP3.B.

In accordance with the Commission's requirement for technology demonstration and deployment projects, for the 2015-2017 Investment Plan the IOUs continue to successfully utilize the joint IOU framework developed for the 2012-2014 cycle. This includes the following four program categories: (1) energy resources integration, (2) grid modernization and optimization, (3) customer-focused products and services, and (4) cross-cutting/foundational strategies and technologies. SCE's 2012 – 2014 and 2015-2017 Investment Plans proposed projects for each of these four areas, focusing on the ultimate goals of promoting greater reliability, lowering costs, increasing safety, decreasing greenhouse gas emissions, and supporting low-emission vehicles and economic development for ratepayers.

c) **EPIC Program Regulatory Process**

The Commission approved SCE's 2012-2014 Application[25] in D.13-11-025 on November 19, 2013. SCE submitted its 2015-2017 Investment Plan Application[26] on May 1, 2014 and the Commission approved the Application in D.15-04-020 on April 9, 2015. The Commission opened a phase II of the proceeding to address projects proposed after Commission approval of an Investment Plan. The Commission issued its Phase II Decision,[27] requiring the IOUs to file a Tier 3 advice letter for any new or materially re-scoped project. This advice filing would need to justify why the project should be given Commission approval, rather than simply waiting for the next investment plan funding cycle. In compliance with the Commission's requirements for the EPIC Program,[28] SCE submits its 2016 Annual Report to provide a status update to the Commission and stakeholders on its program implementation.

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[25] A.12-11-004.
[26] A.14-05-005.
[27] D.15-09-005.
[28] D.12-05-037, Ordering Paragraph (OP) 16, as amended in D.13-11-025, at OPs 53-54 and D.15-04-020 at OP 6.

d) **Coordination**

The EPIC Administrators have collaborated throughout 2016 on the execution of the 2012-2014 and 2015-2017 Investment Plans. Specific examples of the IOUs coordinating with the CEC include:

- Joint Administrators Workshop on June 22, 2016; and
- Joint Administrators Symposium on December 1, 2016.

SCE also supported the CEC's execution of its 2012-2014 and 2015-2017 Investment Plans. The EPIC Administrators met on a near-weekly basis to discuss implementing the 2012-2014 and 2015-2017 Investment Plans and to plan and coordinate the joint stakeholder workshop and joint public symposium. Moreover, SCE had several collaborative meetings with the CEC to help further coordinate the respective investments plans.

e) **Transparent and Public Process/ CEC Solicitation Activities**

In 2016, SCE participated in a stakeholder workshop and public symposium on the execution of its 2012-2014 and 2015-2017 Investment Plans. At the stakeholder workshop held at SCE's Advanced Technology Labs in Westminster, CA on June 22, 2016 the focus was on distribution automation. The workshop highlighted distribution automation and SCE provided presentations on the following projects: Demonstration Test Bed for Advanced Control Systems, Remote Intelligent Switch, and Distributed Optimized Storage (Consideration for Dual Use Operation). Public stakeholders had the opportunity to ask questions specific to project presentations and the EPIC program in general.

In addition, the IOUs and the CEC held the second annual EPIC symposium. This public symposium brought together an array of interested stakeholders to learn about the status of the respective EPIC portfolios. The EPIC symposium was held at the Sacramento Convention Center in Sacramento, CA in Sacramento, CA on December 1, 2016.

SCE supported numerous parties applying for CEC, EPIC funding in 2016. Letters of Support (LOS) and Commitment (LOC) were given to parties showing our support for their bids on CEC projects. In 2016, SCE provided 37 LOS and 8 LOC to a diverse array of parties including private vendors, universities and national laboratories. In SCE nomenclature, a LOS typically supports the premise of a project. In some instances, it will infer technical advisory support, if (A) the project is awarded to the recipient, and (B) the party and SCE come to a mutual understanding of what advisory support will actually be required.

A LOC shows early financial and/or technical support should the project be awarded to the recipient. All public stakeholders continue to have the opportunity to participate in the execution of the Investment Plans by accessing SCE's EPIC website. Through the SCE EPIC website the public can access SCE's Investment Plan Applications, request a LOS or LOC and directly contact SCE with questions pertaining to EPIC.

3. Budget

a) Authorized Budget

(1) 2012 – 2014 Investment Plan

Table 5: 2016 Authorized EPIC Budget

2016 (Jan 1 - Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	$1.3M	$11.9M	$0.33M[29]
CEC Program	$5.3M	$47.7M	

[29] Advice Letter, 2747-E, p. 6.

(2) **2015 – 2017 Investment Plan**

Table 6: 2016 Authorized EPIC Budget

2016 (Jan 1 - Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	$1.4M	$12.5M	$0.35M
CEC Program	$5.6M	$50M	

b) **Commitments/ Encumbrances**

(1) **2012 – 2014 Investment Plan**

As of December 31, 2016, SCE has committed $38,778,768 and encumbered $23,146,836 of its authorized 2012-2014 program budget.

(2) **2015 – 2017 Investment Plan**

As of December 31, 2016, SCE has committed $40,363,017 and encumbered $12,096,976 of its authorized 2015-2017 program budget.

For CEC remittances, SCE remitted $9,003,256.80 for program administration, and $88,501,768.35 for encumbered projects during calendar year 2016.

For CPUC remittances, SCE remitted $349,201 in calendar year 2016.

c) **Dollars Spent on In-House Activities**

(1) **2012 – 2014 Investment Plan**

As of December 31, 2016, SCE has spent $7,821,072[30] on in-house activities.

[30] SCE expended a total of $6,987,776 on in-house activities through 2016 based on the project spreadsheet in Appendix A. SCE's accounting systems calculates in-house labor overheads separately which amounted to $833,296. As a result, SCE expended a total of $7,821,072 on in-house costs.

(2) 2015 – 2017 Investment Plan

As of December 31, 2016, SCE has spent $1,514,634[31] on in-house activities.

d) Fund Shifting Above 5% Between Program Areas

(1) 2012 – 2014 Investment Plan

As of December 31, 2016, SCE does not have any pending fund shifting requests and/or approvals.

(2) 2015 – 2017 Investment Plan

As of December 31, 2016, SCE does not have any pending fund shifting requests and/or approvals.

e) Joint CEC/SCE Projects

As of December 31, 2016, SCE does not have any joint projects with the CEC.

4. Projects

a) High Level Summary

For a summary of project funding for both SCE's 2012-2014 and 2015-2017 Investment Plans, please refer to Table 1 and Table 3 in Section 1b.

b) Project Status Report

Please refer to Appendix A of this Report for SCE's Project Status Report.

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31 SCE expended a total of $1,331,008 on in-house activities through 2016 based on the project spreadsheet in Appendix A. SCE's accounting systems calculates in-house labor overheads separately which amounted to $183,626. As a result, SCE expended a total of $1,514,634 on in-house costs.

c) **Description of Projects:**

(i) **Investment Plan Period**

(ii) **Assignment to Value Chain**

(iii) **Objective**

(iv) **Scope**

(v) **Deliverables**

(vi) **Metrics**

(vii) **Schedule**

(viii) **EPIC Funds Encumbered**

(ix) **EPIC Funds Spent**

(x) **Partners (if applicable)**

(xi) **Match Funding (if applicable)**

(xii) **Match Funding Split (if applicable)**

(xiii) **Funding Mechanism (if applicable)**

(xiv) **Treatment of Intellectual Property (if applicable)**

(xv) **Status Update**

The following project descriptions reflect the projects' status information as of December 31, 2016.

(1) **2012 – 2014 Triennial Investment Plan Projects**

1. Integrated Grid Project – Phase 1

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Grid Operation/Market Design
Objective & Scope: The project will demonstrate, evaluate, analyze and propose options that address the impacts of Distributed Energy Resources (DER) penetration and increased adoption of Distributed Generation (DG) owned by consumers on all segments/aspects of SCE's grid – transmission, distribution and overall "reliable" power delivery cost to SCE customers	

(all tiers). This demonstration project is in effect the next step to the ISGD project. Therefore, this analysis will focus on the effects of introducing emerging and innovative technology into the utility and consumer end of the grid, predominantly the commercial and industrial customers with the ability to generate power with self-owned and operated renewable energy sources, but connected to the grid for "reliability" and "stability" operational reasons. This scenario introduces the need for the utility (SCE) to assess discriminative technology necessary for stabilizing the grid with increased DG adoption, and more importantly, consider possible economic models that would help SCE adopt to the changing regulatory policy and GRC structures. This value-oriented demonstration would inform many key questions that have been asked: • What is the value of distributed generation and where is it most valuable? • What is the cost of intermittent resources? • What is the value of storage and where is it most valuable? • How effectively can demand response manage intermittency and what is the value? • What is the value of flexible demand response (e.g. the flexibility to charge a vehicle over an extended range of time)? • What is the value of controlling a thermostat? • How are these resources/devices co-optimized? • What infrastructure is required to enable an optimized solution? • What incentives/rate structure will enable an optimized solution?
Deliverables: • An IGP cost/benefit analysis and business case • A systems requirement specification • An IGP demonstration architecture • A distributed grid control architecture capable of supporting the use of market mechanism, price signals, direct control or distributed control to optimize reliability and economic factors on the distribution grid • A data management and integration architecture supporting the overarching IGP architecture • A supporting network and cybersecurity architecture for the IGP architecture • Incentive structures that encourage technology adoption that provide benefits to overall system operations • A Volt/Var optimization strategy • RFPs to secure vendor solutions for the field demonstration phase of the IGP project • Post analyses - review, findings and recommendations on GridLAB-D models used in the IGP architecture and design • IGP lab demonstration using a simulated environment • Final project report (Phase 1)
Metrics: 1a. Number and total nameplate capacity of distributed generation facilities

1b. Total electricity deliveries from grid-connected distributed generation facilities
1c. Avoided procurement and generation costs
1d. Number and percentage of customers on time variant or dynamic pricing tariffs
1e. Peak load reduction (MW) from summer and winter programs
1f. Avoided customer energy use (kWh saved)
1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR)
1h. Customer bill savings (dollars saved)
1i. Nameplate capacity (MW) of grid-connected energy storage
3a. Maintain / Reduce operations and maintenance costs
3b. Maintain / Reduce capital costs
3c. Reduction in electrical losses in the transmission and distribution system
3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear
3e. Non-energy economic benefits
3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management
5a. Outage number, frequency and duration reductions
5b. Electric system power flow congestion reduction
5c. Forecast accuracy improvement
5f. Reduced flicker and other power quality differences
5i. Increase in the number of nodes in the power system at monitoring points
7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360);
7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360);
7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360);
7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360);
7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360);
7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360);
7j. Provide consumers with timely information and control options (PU Code § 8360);
7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360);

7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market).		
Schedule: IGP Phase 1: Q2 2014 – Q4 2017		
EPIC Funds Encumbered: $14,203,565	**EPIC Funds Spent:** $14,862,412	
Partners: TBD; SCE is currently exploring collaboration opportunities.		
Match Funding: TBD	**Match Funding split:** TBD	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update In 2016, the Integrated Grid Project (IGP) project team finalized the execution scope, lab testing requirements, and field demonstration approach. The team also completed the architectural and system design of the project as well as completed the procurements with key technology vendors. The project team adopted two additional IGP scope elements: 1) Utilize energy storage as both a reliability and a market device, and 2) Develop an interface structure between IGP systems and 3rd parties for the control and monitoring of DERs. The project team built out and equipped the Advanced Technology (AT) labs, while also beginning the testing of the control systems, Field Area Network (FAN), and integration systems that are at the core of the IGP project. The following activities were completed by the project team in 2016: • Selected the vendors and executed contracts for the IGP control systems and the Utility Integration Bus • Continued to work with site-location owners and SCE legal to secure 3rd party DER resources and associated properties • Obtained internal approvals from the Distribution Standards and Substation Standards committees to allow for timely installation of field equipment • Completed the system and design level project documentation, such as the System Design Document (SDD) and System Requirements Document (SRD) • Tested and down selected the FAN vendors		

• Selected battery energy storage system specifications and site to support IGP project requirements • Conducted collaborative working sessions, known as "Sprints", between SCE, the control vendors and the integration bus vendor to develop integration adapters • Finalized the testing environments and developed lab test plans and procedures for Factory Acceptance Testing (FAT) and Site Acceptance Testing (SAT)

2. Regulatory Mandates: Submetering Enablement Demonstration

<table>
<tr><td colspan="2">Investment Plan Period:
1st Triennial Plan (2012-2014)</td><td colspan="2">Assignment to value Chain:
Demand-Side Management</td></tr>
<tr><td colspan="4">Objective & Scope:
On November 14, 2013, the Commission voted to approve the revised Proposed Decision (PD) Modifying the Requirements for the Development of a Plug-In Electric Vehicle Submetering Protocol set forth in D.11-07-029. The investor-owned utilities (IOUs) are to implement a two phased pilot beginning in May 2014, with funding for both phases provided by the EPIC. This project, Phase I of the pilot will (1) evaluate the demand for Single Customer of Record submetering, (2) estimate billing integration costs, (3) estimate communication costs, and (4) evaluate customer experience. IOU's and external stakeholders will finalize the temporary metering requirements, develop a template format used to report submetered, time-variant energy data, register Submeter Meter Data Management Agents and develop a Customer Enrollment Form, and finalize MDMA Performance Requirements. The IOUs will also solicit a 3rd party evaluator to evaluate customer experience.</td></tr>
<tr><td colspan="4">Deliverables:
1. Submetering Protocol Report
2. Manual Subtractive Billing Procedure
3. 3PE Final Report and Recommendation</td></tr>
<tr><td colspan="4">Metrics:
6a. TOTAL number of SCE customer participants (Phase 1 & 2 each have 500 submeter limit)
6b. Number of SCE NEM customer participants (Phase 1 & 2 each have 100 submeter limit of 500 total)
6c. Submeter MDMA on-time delivery of customer submeter interval usage data
6d. Submeter MDMA accuracy of customer submeter interval usage data</td></tr>
<tr><td colspan="4">Schedule:
Q1 2014 – Q1 2017</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$0</td><td colspan="2">EPIC Funds Spent:
$1,126,459</td></tr>
<tr><td colspan="4">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td colspan="2">Match Funding split:
N/A</td><td>Funding Mechanism:
Pay-for-Performance Contracts</td></tr>
<tr><td colspan="4">Treatment of Intellectual Property</td></tr>
</table>

SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.

Status Update

Lessons learned that will be applied to the Submetering Phase 2 Pilot include:

1. The Submeter MDMAs were not prepared to start the Phase 1 Pilot on September 1, 2014.

   Require more stringent preliminary ED review of stakeholder's qualifications to be a Submeter MDMA including final approval by the IOUs that Submeter MDMA candidates meet all requirements stated in Advice Letter prior to the start of the Pilot.
   In addition, provide the Submetering MDMAs with more comprehensive, detailed training prior to the start of the Phase 2 Pilot to help improve their performance and level of customer satisfaction.

2. The manual customer enrollment process was challenging for our customers and the Submeter MDMAs.

   Streamline the customer enrollment process by simplifying the Customer Enrollment Agreement (CEA); replacing the Phase 1 Excel spreadsheet tracker used to record customer status throughout the Pilot with a more robust, more flexible Access database; and provide the Submeter MDMAs more details when a CEA is returned to them for correction.
3. The term submeter 'accuracy' is equivalent to the same term used in the ANSI C-12 standard or equivalent to 'tolerance' in NIST Handbook 44 Section 3.40 T.2. Require the submeter to demonstrate meter acceptance accuracy of +/-1%, and maintain accuracy of +/- 2% during the Phase 2 Pilot. Submeter MDMA is responsible for describing how they comply with this accuracy requirement prior to pilot installation.

4. Require the submeter's time be synchronized to the Universal Time Coordinate (UTC) time standard as defined by the National Institute of Standards and Technology (NIST), and be within +/- two (2) minutes of UTC, while the EVSE is in service. Submeter MDMA is responsible for describing how they comply with this accuracy requirement prior to pilot installation.

Deliverables:

Customer Enrollment

SCE enrolled and supported 92 residential submeter customers including 13 NEM accounts were limited to a maximum of 12 billing cycles.

   a. 78 0f the 92 enrolled customers completed their maximum of 12 billing cycles.
   b. 14 (15.2%) customers opted to terminate their participation early.
      i. Two customers moved out of SCE's territory.

ii. The remaining twelve customers left the Pilot primarily due to EV charging cost that did not meet their expectations as shown on next page in Figure 7. Final Report Attached for your reference.

3. Distribution Planning Tool

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Distribution
Objective & Scope: This project involves the creation, validation, and functional demonstration of an SCE distribution system model that will address the future system architecture that accommodates distributed generation (primarily solar photovoltaic), plug-in electric vehicles, energy storage, customer programs (demand response, energy efficiency), etc. The modeling software to be used allows for implementation of advanced controls (smart charging, advanced inverters, etc.). These controls will enable interaction of a residential energy module and a power flow module. It also enables the evaluation of various technologies from an end-use customer perspective as well as a utility perspective, allowing full evaluation from substation bank to customer. This capability does not exist today. The completed model will help SCE demonstrate, communicate and better respond to technical, customer and market challenges as the distribution system architecture evolves.	
Deliverables: • Grid LAB-D user interface • SCE circuit model • Updated GridLAB-D to handle Cyme 7 database • Base cases & benchmark • Specifications for test cases from stakeholders • Created test cases • Periodic updates/meetings with stakeholders • Executed test cases • Final project report	
Metrics: 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 5c. Forecast accuracy improvement 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)	

7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360); 8c. Number of times reports are cited in scientific journals and trade publications for selected projects. 8d. Number of information sharing forums held. 8f. Technology transfer 9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market).
Schedule: Q1 2014 – Q1 2017

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,225,754

Partners: N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts

Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update In 2016 the project demonstrated a fully dynamic analysis to determine the DER hosting capacity at individual nodes within two distinct areas that represent the wide variety of distribution systems within SCE's service territory. The project examined the hosting capacity based on limiting categories of thermal rating, power quality and voltage criteria including steady state voltage and voltage fluctuation, protection coordination requirements, safety and reliability, as well as substation limitations. The project employed two different methodologies to calculate the DER hosting capacities under various scenarios such as with/without reverse power flow at distribution substation bus and various loading conditions throughout the year. The Streamlined Method performs one power flow simulation for each scenario and then extracts necessary quantities and use equations to determine the hosting capacities for each of the limiting categories. The Iterative Method utilizes iterative power flow simulations to determine the hosting capacities for each of the limiting categories. The hosting capacity results were published on SCE's Distributed Energy Resource Interconnection Map (DERiM) to share with the public. Final Report attached for your reference.

4. Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Demand-Side Management
Objective & Scope: The Beyond the Meter (BTM) project will demonstrate the use of a DER management system to interface with and control DER based on customer and distribution grid use cases. It will also demonstrate the ability to communicate near-real time information on the customer's load management decisions and DER availability to SCE for grid management purposes. Three project objectives include: 1) development of a common set of requirements that support the needs of a variety of stakeholders including customers, distribution management, and customer program; 2) validation of standardized interfaces, functionalities, and architectures required in new Rule 21 proceedings, IOU Implementation Guide, and UL 1741/IEEE 1547 standards; 3) collection and analysis measurement and cost/benefits data in order to inform the design of new tariffs, recommend the deployment of new technologies, and support the development of new programs.	
Deliverables: • "Enabling Communication Unification" status report • Written specifications for all three class of devices (EVSEs, solar inverters, and RESUs) • "Industry Harmonization and Closing Gaps" report • Receive devices for testing • Complete final report and recommendations	
Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5b. Electric system power flow congestion reduction 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360);	

7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360);
7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360);
7g. Integration of cost-effective smart appliances and consumer devices (PU Code § 8360);
7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360);
7j. Provide consumers with timely information and control options (PU Code § 8360);
7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360);
7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)
8b. Number of reports and fact sheets published online
8d. Number of information sharing forums held.
8f. Technology transfer
9a. Description/documentation of projects that progress deployment, such as Commission approval of utility proposals for wide spread deployment or technologies included in adopted building standards.
9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs
9c. EPIC project results referenced in regulatory proceedings and policy reports.
9d. Successful project outcomes ready for use in California IOU grid (Path to market).

Schedule:
Q3 2014 – Q4 2017

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$2,062,026	$1,411,303

Partners:
N/A

Match Funding:	**Match Funding split:**	**Funding Mechanism:**
N/A	N/A	Pay-for-Performance Contracts

Treatment of Intellectual Property
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.

Status Update
During 2016, the project team engaged internal and stakeholder groups including Grid Modernization, Sunspec Alliance, and the Smart Inverter Working Group in order to understand and document lower-level requirements and use cases critical to SCE, including regulatory requirements (Rule 21) related to the interconnection of Beyond The Meter DERs. The technical team used the input to complete a Request for Information that

resulted in a pool of candidate vendors and a Request for Proposal to be released in early 2017.

5. Portable End-to-End Test System

Investment Plan Period: 1st Triennial Plan (2012-2014)		**Assignment to value Chain:** Transmission
Objective & Scope: End-to-end transmission circuit relay testing has become essential for operations and safety. SCE technicians currently test relay protection equipment during commissioning and routing testing. Existing tools provide a limited number of scenarios (disturbances) for testing, and focus on testing protection elements; not testing system protection. This project will demonstrate a robust portable end-to-end toolset (PETS) that addresses: 1) relay protection equipment, 2) communications, and 3) provides a pass/fail grade based on the results of automated testing using numerous simulated disturbances. PETS will employ portable Real-Time Digital Simulators (RTDS's) in substations at each end of the transmission line being tested. Tests will be documented using a reporting procedure used in the Power Systems Lab today, which will ensure that all test data is properly evaluated.		
Deliverables: • PETS portable RTDS test equipment • PETS operating instructions • PETS standard test report • Final project report		
Metrics: 3a. Maintain / Reduce operations and maintenance costs 5a. Outage number, frequency and duration reductions 6a. Reduction in testing cost 6b. Number of terminals tested on a line (more than 2 terminals/substations) 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9e. Technologies available for sale in the market place (when known).		
Schedule: Q1 2014 – Q4 2015		
EPIC Funds Encumbered: $0		**EPIC Funds Spent:** $39,564
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts

Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update The test setup yielded lessons learned that pointed the team to determining that this technology was not a viable option at this time. For example, the test set up required significant power to drive 5 Doble test sets, as well as an outdoor area to set up a GPS antenna. Additionally the test setup needed to mirror field conditions (i.e., no external monitors, all test equipment needed to be transportable, etc.), so that we would be able to perform the test in a remote location without any unexpected events. Furthermore, the setup required a mobile RTDS unit and Doble test set per terminal, meaning that 3 of each (RTDS unit and Doble test set) would be needed for lines that contained 3 terminals. The team's analysis discovered however, that in our system very few 220 lines in fact have more than 2 terminals, and that the existing test systems were adequate options for testing 2 terminal lines. The objective of the PETS project was to meet EPIC's primary principle criteria of providing greater reliability to the customers. However, it was determined that the benefits associated with this demonstration project did not outweigh the costs and ultimately it would not provide added value. The project was successful in proving that the tools exist to conduct advanced end-to-end relay testing, albeit not cost effective. Final Report was previously provided.

6. Voltage and VAR Control of SCE Transmission System

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Transmission
Objective & Scope: This project involves the demonstration of software and hardware products that will enable automated substation volt/var control. Southern California Edison (SCE) will demonstrate a Substation Level Voltage Control (SLVC) unit working with a transmission control center Supervisory Central Voltage Coordinator (SCVC) unit to monitor and control substation voltage. The scope of this project includes systems engineering, testing, and demonstration of the hardware and software that could be operationally employed to manage substation voltage.	
Deliverables: • Demonstration design specification • Construction documents: drawings, cable schedule, and bill of material • Monitoring console software and hardware	

- Advanced Volt/VAR Control (AVVC) testing
- Field deployment
- Controller operation monitoring and adjustment
- AVVC final report and closeout

Metrics:
3a. Maintain / Reduce operations and maintenance costs
3c. Reduction in electrical losses in the transmission and distribution system
3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear
7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)
8b. Number of reports and fact sheets published online
8d. Number of information sharing forums held.
8f. Technology transfer
9c. EPIC project results referenced in regulatory proceedings and policy reports.
9d. Successful project outcomes ready for use in California IOU grid (Path to market).

Schedule:
Q1 2014 – Q4 2018

EPIC Funds Encumbered: $87,875	**EPIC Funds Spent:** $407,037

Partners:
N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts

Treatment of Intellectual Property
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.

The project was re-scoped and re-baselined earlier in 2016 to better align with company goals and stakeholder needs. The current project scope includes development, customization, and implementation of a voltage and VAr management tool that optimizes the voltage of the transmission and sub-transmission systems by optimizing the control over discrete reactive power resources. An offline study was conducted to quantify the benefits and estimate dollar savings of optimizing voltage profile to minimize active and reactive power losses on the transmission grid. In addition, to gather business and system requirements needed for the development of the tool, interviews with system operators (at the substation level) were conducted to understand how voltage and VAr management is performed locally. Bi-weekly stakeholder meetings were conducted to gather requirements from multiple stakeholder groups.

7. Superconducting Transformer (SCX) Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)		**Assignment to value Chain:** Distribution
Objective & Scope: <u>This project was cancelled in 2014. No further work is planned.</u> *Original Project Objective and Scope:* SCE will support this $21M American Reinvestment and Recovery Act (ARRA) Superconducting Transformer (SCX) project by providing technical expertise and installing and operating the transformer at SCE's MacArthur substation. The SCX prime contractor is SuperPower Inc. (SPI), teamed with SPX Transformer Solutions (SPX) {formerly Waukesha Electric Systems}. SCE has provided two letters of commitment for SCX. The SCX project will develop a 28 MVA High Temperature Superconducting, Fault Current Limiting (HTS-FCL) transformer. The transformer is expected to be installed in 2015. SCE is supporting this project and is not an ARRA grant sub-recipient. SCE is being reimbursed for its effort by EPIC. SCE's participation in this project was previously approved under the now-defunct California Energy Commission's PIER program.		
Deliverables: • N/A		
Metrics: N/A		
Schedule: Project was cancelled in Q2 2014.		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $10,241	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed.		
Status Update SPX Transformer Solutions officially withdrew support from the project in Q2, 2014. As a result, SuperPower could no longer complete the delivery of the HTS-FCL transformer to SCE. SuperPower communicated the desire to identify a new transformer manufacturer as a partner, but was unable to secure one within a reasonable timeframe. At the time of SPX's withdrawal, SCE did not have an executed agreement with SuperPower. SCE formally cancelled this project in Q3 2014.		

8. State Estimation Using Phasor Measurement Technologies

Investment Plan Period:	**Assignment to value Chain:**

1st Triennial Plan (2012-2014)	Grid Operation/Market Design

Objective & Scope:
Accurate and timely power system state estimation data is essential for understanding system health and provides the basis for corrective action that could avoid failures and outages. This project will demonstrate the utility of improved static system state estimation using Phasor Measurement Unit (PMU) data in concert with existing systems. Enhancements to static state estimation will be investigated using two approaches: 1) by using GPS time to synchronize PMU data with Supervisory Control and Data Acquisition (SCADA) system data; 2) by augmenting SCE's existing conventional state estimator with a PMU based Linear State Estimator (LSE).

Deliverables:

- Demonstrated algorithm performance based on observations.
- Report that addresses tests conducted and test results.
- Final project report.

Metrics:
6a. Enhanced grid monitoring and on-line analysis for resiliency
7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
8b. Number of reports and fact sheets published online
8d. Number of information sharing forums held
8f. Technology transfer
9d. Successful project outcomes ready for use in California IOU grid (Path to market)
9e. Technologies available for sale in the market place (when known)

Schedule:
Q2 2014 – Q4 2017

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$1,046,100	$796,574

Partners:
N/A

Match Funding:	**Match Funding split:**	**Funding Mechanism:**
N/A	N/A	Pay-for-Performance Contracts

Treatment of Intellectual Property
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.

Status Update
In 2016, SCE worked with the Electric Power Group (EPG) on the State Estimation using PMU to pilot the enhanced Linear State Estimator (eLSE) at Grid Control Center to perform data validation and conditioning on the synchrophasor stream and generate an estimate of phasors of nearby stations at same synchrophasor rate to increase systems observability. The team collaborated and worked on the deployment of the Grid Control Center (GCC) Real-Time Dynamics Management System/eLSE that included:
1. RTDMS Deployment at GCC for the Pilot Project including commissioning of RTDMS.

2. eLSE deployment, integration and implementation at GCC for expanding observability and data quality. 3. Developed and documented detailed procedures on how to modify and augment LSE to accommodate the future expansion of the SCE PMU infrastructure. 4. EPG and SCE provided 6 operator training sessions to over 22 SCE dispatchers/PSC Employees.

9. Wide-Area Reliability Management & Control

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Grid Operation/Market Design	
Objective & Scope: With the planned wind and solar portfolio of 33% penetration, a review of the integration strategy implemented in the SCE bulk system is needed. The basic premise for the integration strategy is that a failure in one area of the grid should not result in failures elsewhere. The approach is to minimize failures with well designed, maintained, operated and coordinated power grids. New technologies can provide coordinated wide-area monitoring, protection, and control systems with pattern recognition and advance warning capabilities. This project will demonstrate new technologies to manage transmission system control devices to prevent cascading outages and maintain system integrity.		
Deliverables: • Lab demonstration of control algorithms using real time simulations with Hardware in the loop (RTWHIL) • Develop recommendations based on the control system testing • Final project report		
Metrics: 6a. Enhanced contingency planning for minimizing cascading outages 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer		
Schedule: Q2 2014 – Q3 2017		
EPIC Funds Encumbered: $927,510	**EPIC Funds Spent:** $441,055	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update		

In 2016, SCE has worked with Siemens on utilizing the Devers control system to increase the bulk system resilience. The project team implemented some initial test using a newly developed Devers Static Var Compensator (SVC) model into Western Electricity Coordinating Council case and test the response under different system contingencies. The next steps is for the team to finalize Devers SVC control system parameters tuning and implementing the updates to Devers SVC control system.

10. Distributed Optimized Storage (DOS)

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Distribution
Objective & Scope: This field pilot will demonstrate end-to-end integration of multiple energy storage devices on a distribution circuit/feeder to provide a turn-key solution that can cost-effectively be considered for SCE's distribution system, where identified feeders can benefit from grid optimization and variable energy resources (VER) integration. To accomplish this, the project team will first identify distribution system feeders where multiple energy storage devices can be operated centrally. Once a feeder is selected, the energy storage devices will be deployed and tested to demonstrate seamless utility integration, control, and operation of these devices using a single centralized controller. At the end of the project, SCE will have established clear methodologies for identifying feeders that can benefit from distributed energy storage devices and will have established necessary standards-based hardware and control function requirements for grid optimization and renewables integration with distributed energy storage devices.	
Deliverables: • Target feeder models • Selected feeders for the project • Requirement development for solution • RFP for all devices • Procurement of all devices • Evaluation of centralized controller and representative energy storage devices • Test platform readiness for protection evaluation • Testing of various energy storage footprints for protection • Engagement of all expected SCE departments for deployment • Procurement of M&V equipment • Deployment of M&V Equipment and energy storage devices and centralized controller • M&V complete and final report	
Metrics: 1c. Avoided procurement and generation costs 1i. Nameplate capacity (MW) of grid-connected energy storage 3b. Maintain / Reduce capital costs 5f. Reduced flicker and other power quality differences	

5i. Increase in the number of nodes in the power system at monitoring points 6a. Benefits in energy storage sizing through device operation optimization 6b. Benefits in distributed energy storage deployment vs. centralized energy storage deployment 7a. Description of the issues, project(s), and the results or outcomes 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports.
Schedule: Q2 2014 – Q4 2017

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $81,861

Partners: TBD

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts

Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update During 2016, the DOS project continued to work with the Integrated Grid Project and the SCE's Energy Storage Ownership Initiative (ESOI). The team conducted multiple workshops to develop Use Cases, including the Dual Use capability. The team also developed draft functional and non-functional requirements.

11. Outage Management and Customer Voltage Data Analytics Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Grid Operation/Market Design
Objective & Scope: Voltage data and customer energy usage data from the Smart Meter network can be collected and leveraged for a range of initiatives focused on achieving operational benefits for Transmission & Distribution. Before a full implementation of this new approach can be considered, a Pilot project will be conducted to understand how voltage and consumption data can be best collected, stored, and integrated with T&D applications to provide analytics and visualization capabilities. Further, Smart Meter outage and restoration event	

(time stamp) data can be leveraged to improve customer outage duration and frequency calculations. Various stakeholders in T&D have identified business needs to pursue more effective and efficient ways of calculating SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index), and MAIFI (Momentary Average Interruption Frequency Index) for internal and external reporting. Before a full implementation of this new approach can be considered, a Pilot project will be conducted to understand the feasibility and value of providing smart meter data inputs and enhanced methodology for calculating the Indexes. The Pilot will focus on a limited geography (SCE District or Region) to obtain the Smart Meter inputs to calculate the Indexes and compare that number with the current methodologies to identify any anomalies. A hybrid approach using the Smart Meter-based input data combined with a better comprehensive electric connectivity model obtained from GIS may provide a more efficient and effective way of calculating the Indexes. Additionally, an effort to evaluate the accuracy of the Transformer Load Mapping data will be carried out.		
Deliverables: • Voltage Analytics for Power Quality Model • Simulated Circuit Condition Model • Customer and Transformer Load Analysis Model • Enhanced Inputs and SAIDI/SAIFI Analysis • Final Project Report		
Metrics: 3a. Maintain / Reduce operations and maintenance costs 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 6a. Enhance Outage Reporting Accuracy and SAIDI/SAIFI Calculation 8b. Number of reports and fact sheets published online 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports.		
Schedule: Q1 2014 – Q4 2015		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,020,421	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update The project was successfully completed in 2015.		

The demonstration concluded with user testing/evaluation by Distribution system engineers and planners and outage reporting analysts to educate them of the value, test the functionality of this tool and to receive feedback on opportunities for improvement. The demonstration of the use cases with the analytics platform was so successful that SCE is proceeding with an enterprise-wide deployment of a platform with similar functionality that uses smart meter data. The feasibility study was on the potential use of meter outage events in SAIDI/SAIFI metric calculation. It included an evaluation of the existing outage analysis process and the changes and benefits of using meter outage events with time stamps. The study concluded with comparison/validation testing between using the existing method versus meter events time stamps in calculating Customer Minutes of Interruption (basis for System Average Interruption Duration Index/System Average Interruption Frequency Index) values on a single area outage as well as for an entire District. The general conclusion from the comparison testing was that using meter event data can be an efficient and accurate method for calculating CMI values. The study also made recommendations. These included (i) automation of some steps of the outage analysis process, (ii) implementation of interfaces between databases including Outage Management System (OMS), Outage Database and Reliability Metrics (ODRM) and Edison Smart Connect Data Warehouse (ESCDW) to enable sharing of data and (iii) conduct a study to capture outages of meters that do not generate (i.e. non-smart meters) or communicate meter events. Final Report was previously submitted.

12. SA-3 Phase III Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Transmission
Objective & Scope: This project is intended to apply the findings from the Substation Automation Three (SA-3) Phase II (Irvine Smart Grid Demonstration) project to demonstrate real solutions to automation problems faced by SCE today. The project will demonstrate two standards-based automation solutions (sub-projects) as follows: Subproject 1 (Bulk Electric System) will address issues unique to transmission substations including the integration of centrally managed critical cyber security (CCS) systems and NERC CIP compliance; Subproject 2 (Hybrid) will address the integration of SA-3 capabilities with SAS and SA-2 legacy systems. Furthermore, as part of the systems engineering the SA-3 technical team will demonstrate two automation tools as follows: Subproject 3 (Intelligent Alarming) will allow substation operators to pin-point root cause issues by analyzing the various scenarios and implement an intelligent alarming system that can identify the source of the problem and give operators only the relevant information needed to make informed decisions; and Subproject 4 (Real Time Digital Simulator (RTDS) Mobile Testing) will explore the benefits of an automated testing using a mobile RTDS unit, and propose test methodologies that can be implemented into the factory acceptance testing (FAT) and site acceptance testing (SAT) testing process.	

<table>
<tr><td colspan="3">Deliverables:
• Bulk & Hybrid System Design Drawings & Diagrams
• Hybrid System Deployment and Demonstration
• BES System Deployment and Demonstration
• Final Project Report</td></tr>
<tr><td colspan="3">Metrics:
3a. Maintain / Reduce operations and maintenance costs
3b. Maintain / Reduce capital costs
5a. Outage number, frequency and duration reductions
5i. Increase in the number of nodes in the power system at monitoring points
6a. Increased cybersecurity
7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)
7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
8b. Number of reports and fact sheets published online
8d. Number of information sharing forums held.
8f. Technology transfer
9c. EPIC project results referenced in regulatory proceedings and policy reports
9d. Successful project outcomes ready for use in California IOU grid (Path to market)
9e. Technologies available for sale in the market place (when known)</td></tr>
<tr><td colspan="3">Schedule:
Q1 2014 – Q1 2018</td></tr>
<tr><td>EPIC Funds Encumbered:
$670,221</td><td colspan="2">EPIC Funds Spent:
$1,467,960</td></tr>
<tr><td colspan="3">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td>Match Funding split:
N/A</td><td>Funding Mechanism:
Pay-for-Performance Contracts</td></tr>
<tr><td colspan="3">Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="3">Status Update:
2016 Update :
The 2015 decision to reduce the SA-3 Phase III EPIC I budget from $10.4M to $4.1M resulted in stakeholder discussions which have now concluded, focusing the project on demonstrating SA-3 Bulk station capabilities.</td></tr>
</table>

To accomplish the required budget reduction:

1- SA-3 Hybrid scope has been completely dropped from the SA-3 phase III demonstration.
2- SA-3 intelligent Alarming has been completely dropped from SA-3 phase III demonstration and moved to the System intelligence and Situational Awareness project under EPIC II funding
3- SA-3 real Time Simulator (RTDS) Mobile Testing has been completely dropped from SA-3 phase III demonstration and moved to the System intelligence and Situational Awareness project under EPIC II funding
4- The field portion of the SA-3 Bulk station demonstration has been completely dropped from SA-3 phase III demonstration and planned to move to EPIC III funding.
5- The SA-3 Bulk station Lab demonstration schedule has been extended to December 31, 2017 as a result of protracted discussions with stakeholders.

2016 Milestone Achieved:

- Substation Engineering contractor selection complete
- Engineering design SOW has been finalized and it has issued for bid
- Engineering Design contractor RFP vendor selection has been completed
- Engineering Design contractor purchase order has issued and Engineering design has started
- SA-3 Data Concentrator Service RFP has been issued
- The Engineering preliminary standards has created and sent out to the engineering contractor
- The HMI Request for Budgetary proposal has been issued
- Engineering contractor completed the design and the Engineering design is on Stake-holder review
- HMI Service procurement has been completed
- Substation Management System RFP has been issued
- Engineering Design review has been completed
- HMI customization has been started
- HMI configuration files testing has been started

13. Next-Generation Distribution Automation

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Distribution
Objective & Scope: SCE's current distribution automation scheme often relies on human intervention that can take several minutes (or longer during storm conditions) to isolate faults, is only capable of automatically restoring power to half of the customers on the affected circuit, and needs to	

be replaced due to assets nearing the end of their lifecycle. In addition, the self-healing circuit being demonstrated as part of the Irvine Smart Grid Demonstration is unique to the two participating circuits and may not be easily applied elsewhere. As a result, the Next-Generation Distribution Automation project intends to demonstrate a cost-effective advanced automation solution that can be applied to the majority of SCE's distribution circuits. This solution will utilize automated switching devices combined with the latest protection and wireless communication technologies to enable detection and isolation of faults before the substation circuit breaker is opened, so that at least 2/3 of the circuit load can be restored quickly. This will improve reliability and reduce customer minutes of interruption. The system will also have directional power flow sensing to help SCE better manage distributed energy resources on the distribution system. At the end of the project, SCE will provide reports on the field demonstrations and recommend next steps for new standards for next-generation distribution automation.
Deliverables: • Remote Intelligent Switch demonstration and report • Overhead and Underground Remote Fault Indicators demonstration and report • Intelligent Fuses demonstration and report • Power Electronic Transformer demonstration and report • Secondary Network Monitoring demonstration and report • Final Project Report
Metrics: 3a. Maintain / Reduce operations and maintenance costs 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 5i. Increase in the number of nodes in the power system at monitoring points 6a. Improve data accuracy for distribution substation planning process 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held.

8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
Schedule: Q1 2014 – Q1 2017

EPIC Funds Encumbered: $3,062,659	**EPIC Funds Spent:** $4,175,029

Partners: N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: Remote Intelligent Switch (RIS) Following activities were accomplished during 2016 calendar year: • Enhanced system logic to accommodate expanded system requirements and behavior characteristics; • Further enhance hardware design resulting in two additional prototype designs; • Successfully accomplished Factory Acceptance Testing (FAT) and Site Acceptance Testing (SAT) activities; • Demonstrated 2.5 scheme at EDEF demonstration facility; and, • Successfully commissioned pilot (2.5 scheme) on the Poke and Bingo circuits. <u>High Impedance Fault Detection</u> Existing high impedance fault detection solutions available in the market focus on current and voltage monitoring; however, evaluation results demonstrate none of these technologies have been able to securely detect high impedance faults reliably (too many false alarms). As a result, a new approach is necessary and SCE's Advanced Technology considers the reflectometry-based solution as an innovative and promising approach. Advanced Technology and Apparatus Engineering are working with Southwest Research Institute (SWRI) to demonstrate the feasibility of implementing a reflectometry-based solution for detection of high impedance faults. <u>Long Beach Network Situation Awareness</u> • Completed the procurement of Current Monitoring Device for the Long Beach Network, and it currently in the final phase of testing.

14. Enhanced Infrastructure Technology Evaluation

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Distribution

Objective & Scope: At the request of Distribution Apparatus Engineering (DAE) group's lead Civil Engineer, Advanced Technology (AT) will investigate, pilot, and come up with recommendations for enhanced infrastructure technologies. The project will focus on evaluating advanced: distribution sectional poles (hybrid, coatings, etc.), concealed communications on assets, vault monitoring systems (temperature, water, etc.), and vault ventilation systems. Funding is required to investigate the problem, engineering, pilot alternatives, and come up with recommendations. DAE sees the need for poles that can withstand fires and have a better life cycle cost, and provide installation efficiencies when compared to existing wood pole replacements. Due to increased city restrictions, there is a need for more concealed communications on our assets such as streetlights (e.g., on the ISGD project, the City of Irvine wouldn't allow SCE to install repeaters on streetlights due to aesthetics). DAE also sees the need for technologies that may minimize premature vault change-outs (avg. replacement cost is ~$250K). At present, DAE does not have the necessary real-time vault data to sufficiently address the increasing vault deterioration issue nor do we utilize a hardened ventilation system that would help this issue by removing the excess heat out of the vaults (blowers last ~ 2 years, need better bearings for blower motors, etc.).		
Deliverables: • Vault Monitoring Technologies Demonstration Report • Vault Ventilation Field Demonstration Report • Hybrid Pole Demonstration Report • Concealed Communication Assets Demonstration Report • Final Project Report		
Metrics: 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 4g. Wildlife fatality reductions (electrocutions, collisions) 5a. Outage number, frequency and duration reductions 6a. Operating performance of underground vault monitoring equipment 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports		
Schedule: Q2 2014 – Q4 2017		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $79,119	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property:		

SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: This project was completed in 2016. Existing blowers use motors that are not enclosed and allow moisture into the motor, use un-sealed ABEC-1 bearings, and have impellers that are balanced to grade G 6.3. Key features of the hardened blower specification are: severe duty totally enclosed fan cooled motor (IEEE 841 or equivalent), double sealed ABEC-5 grade bearings, impeller balanced to a higher quality grade G 2.5, and stainless steel louver rivets. After six months in service, the blower showed no signs of corrosion, the noise level reading stayed consistent at 85 dB (install vs. 6 months later) which is indicative that bearings & balancing are as installed. Based on these results, SCE is confident that use of a hardened blower will significantly reduce the meant time between failure (2 years). Based on our engineering judgement, test results and evaluation, we expect that the new hardened vault blower could last up to 10 years. We recommend standardizing the new blower going forward. We also recommend that Engineering continues. Final Report was previously provided.

15. Dynamic Line Rating Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Transmission
Objective & Scope: Transmission line owners apply fixed thermal rating limits for power transmission lines. These limits are based on conservative assumptions of wind speed, ambient temperature and solar radiation. They are established to ensure compliance with safety codes, maintain the integrity of line materials, and ensure network reliability. Monitored transmission lines can be more fully utilized to improve network efficiency. Line tension is directly related to average conductor temperature. The tension of a power line is directly related to the current rating of the line. This project will demonstrate the CAT-1 dynamic line rating solution. The CAT-1 system will monitor the tension of transmission lines in real-time to calculate a dynamic daily rating. If successful, this solution will allow SCE to perform real-time calculations in order to determine dynamic daily rating of transmission lines, thus increasing transmission line capacity.	
Deliverables: • Installed Dynamic Line Rating System Prototypes • Final Project Report	
Metrics: 3b. Maintain / Reduce capital costs 5b. Electric system power flow congestion reduction 6a. Increased power flow throughput	

7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
Schedule: Q2 2014 – Q1 2016

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $469,079

Partners: N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: Although the project was cancelled before construction to install the equipment started, some initial studies were conducted. The main study that was conducted was a Path line-of-site survey that is essential to the success of communication. Poles M3-P4, M3-P7 and M4-P2 we surveyed for line-of-site with the antenna mounted on the transmission tower at Barre substation. It was determined that all three paths are obstructed by vegetation, which could potentially introduce interference in communication. In early 2016, a decision was made not to continue the work after the vendor decided not to support Dynamic Line Rating after the end of the demonstration phase. SCE closed this project out in 2016. Final report attached for your reference.

16. Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Grid Operation/Market Design
Objective & Scope: Viasat in partnership with SCE and Duke Energy has been awarded a DOE contract (DE-0E0000675) to deploy a Cyber-intrusion Auto-response and Policy Management System	

(CAPMS) to provide real-time analysis of root cause, extent and consequence of an ongoing cyber intrusion using proactive security measures. CAPMS will be demonstrated in the SCE Advanced Technology labs at Westminster, CA. The DOE contract value is $6M with SCE & Duke Energy offering a cost share of $1.6M and $1.2M respectively.
Deliverables: • System Requirements Artifact • Measurement and Validation Data • System Test Results • Final Project Report
Metrics: 5a. Outage number, frequency and duration reductions 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 10a. Description or documentation of funding or contributions committed by others 10c. Dollar value of funding or contributions committed by others.
Schedule: Q3 2014 – Q3 2015

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,809,323

Partners: Viasat; Duke Energy

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: This project was completed in 2015 with a Final Report attached to the EPIC Annual Report submitted in February 2016.

(2) 2015 – 2017 Triennial Investment Plan Projects

1. Integration of Big Data for Advanced Automated Customer Load Management

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Demand-Side Management
Objective & Scope:	

This proposed project builds upon the “Beyond the Meter Advanced Device Communications” project from the first EPIC triennial investment plan, and purposes to demonstrate how the concept of “big data” can be leveraged for automated load management. More specifically, this potential project would demonstrate the use of big data acquired from utility systems such as SCE’s advanced metering infrastructure (AMI), distribution management system (DMS), and Advanced Load Control System (ALCS) to determine the optimal load management scheme and execute by communicating to centralized energy hubs at the customer level.

Deliverables:

- DERMS Functional Specification
- Acceptance Test Plan and Report
- Final Project Report

Metrics:

7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)

7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)

7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)

7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360)

7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)

8e. Stakeholders attendance at workshops

8f. Technology transfer

Schedule:

2016-2017

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$92,160	$109,289

Partners:

TBD

Match Funding:	**Match Funding split:**	**Funding Mechanism:**
TBD	TBD	Pay-for-Performance Contracts

Treatment of Intellectual Property:

SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: In 2016 the team collaborated with key internal and external stakeholders including Grid Modernization, SunSpec Alliance, the CPUC Smart Inverter Working Group and IEEE to develop use cases, requirements, and architectures. The team also worked with SCE's Integrated Grip Project to determine methods to demonstrate the integration of IEEE 2030.5 interfaces and services into existing and new back office systems, including multiple control systems utilizing a bus-base architecture. This documentation was included in a Request for Proposal to procure an IEEE 2030.5 application server related services. The team evaluated the RFP responses and selected a vendor, and is currently negotiating and finalizing the contract."

2. Advanced Grid Capabilities Using Smart Meter Data

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution	
Objective & Scope: This project will examine the possibility of establishing the Phasing information for distribution circuits, by examining the voltage signature at the meter and transformer level, and by leveraging the connectivity model of the circuits. This project will also examine the possibility of establishing transformer to meter connectivity based on the voltage signature at the meter and at the transformer level.		
Deliverables: • Validated TLM algorithm • Validated Phase ID algorithm • Final project report		
Metrics: 3a. Maintain / Reduce operations and maintenance costs 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 8d. Number of information sharing forums held 8f. Technology transfer		
Schedule: Q3 2015 – Q1 2017		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $279,862	
Partners: TBD		
Match Funding: TBD	**Match Funding split:** TBD	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		

Status Update:
The project consists of two sub-project: transformer to meter correlation and service phase identification. The following activities were completed in 2016: Meter/Transformer correlations: - Successfully tested/demonstrated algorithms on two sample circuits. The stakeholders requested demonstration on additional circuits to confirm accuracy consistency. - After demonstrating consistency on the additional circuits, worked with IT to implement the algorithms in the production environment. Service Phase Identification: - Tested/demonstrated algorithms from EPRI on two sample circuits. - Contracted with a Consultant and demonstrated his algorithms on the same two sample circuits. After a comparison of the two approaches (EPRI and Consultant), the Consultant's algorithm was selected and will be demonstrated further in 2017 on additional types of circuit configurations.

3. Proactive Storm Impact Analysis Demonstration

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution
Objective & Scope: This project will demonstrate proactive storm analysis techniques prior to its arrival and estimate its potential impact on utility operations. In this project, we will investigate some technologies that can model a developing storm and its potential movement through the utility service territory based on weather projections. This information and model will then be integrated with the Geographic Information System (GIS) electrical connectivity model, Distribution Management System (DMS), and Outage Management System (OMS) functionalities, along with historical storm data to predict the potential impact on the service to customers. In addition, this project will demonstration the integration of near real time meter voltage data with the GIS network to develop a simulated circuit model that can be effectively utilized for storm management and field crew deployment.	
Deliverables: • RFP Package • Requirements / Use Cases • Measurement and Validation Plan • Supplier's Pilot Report • Technology Transfer Plan • Final project report	

Metrics: 2a. Hours worked in California and money spent in California for each project 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 8f. Technology transfer 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)		
Schedule: Q3 2015 – Q4 2017		
EPIC Funds Encumbered: $1,198,480	**EPIC Funds Spent:** $655,100	
Partners: TBD		
Match Funding: TBD	**Match Funding split:** TBD	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: In 2016 the project team demonstrated storm impact prediction models for all regions in SCE territory, at the district level, and across all asset types, including transformers, poles, and spans of wire, overhead and underground. Additionally, the team completed two user test sessions, for versions 1 and 2, respectively, with stakeholder users throughout SCE including Grid Operations, IT, Business Resiliency, and Field Services. The user test sessions served to provide key requirements for model versions 1 and 2. The team is scheduled to validate models in 2017 in a Hadoop cloud based platform to ensure production readiness by 2018.		

4. Next-Generation Distribution Equipment & Automation - Phase 2

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution
Objective & Scope: This project will leverage lessons learned from the Next Generation Distribution Automation – Phase 1 project performed in the first EPIC triennial investment plan period. This project will focus on integrating advanced control systems, modern wireless communication systems, and the latest breakthroughs in distribution equipment and sensing technology to develop a complete system design that would be a standard for distribution automation and advanced distribution equipment.	
Deliverables:	

• **Hybrid Pole:** specification and report • **Underground Antenna:** functional specification, lab test report, pilot summary and report • **Underground Remote Fault Indicator:** identify viable products, publish standard, SCE-configured prototype Mobile Application and report • **Long Beach Network:** improved situational awareness and alarm approach, AT Laboratory SCADA network, DMS back-office recommended architecture and algorithm document, Software Requirements Document, Long Beach Distribution Network Contingency Analysis and Selection Algorithm Report, Standard, FAT & SAT Test Plan/Acceptance Criteria, FAT report, SAT report, training documents and report • **Remote Intelligence Switch:** Substation Radios, Field Radios, Support Software, Underground Interrupters, Documentation and report • **Intelligent Fuse:** delivery of single phase unit, single phase unit standard approval and publication, training of single phase unit, final report of single phase unit, delivery of three phase unit, three phase unit standard approval and publication, training of three phase unit and final report of three phase unit • **High Impedance:** Prototype 1, Prototype 2, Phase 2B Test Documentation and report
Metrics: 3a. Maintain/Reduce operations and maintenance costs 3e. Non-energy economic benefits 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communication concerning grid operations and status, and distribution automation (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
Schedule: Q3 2016 – Q4 2019

EPIC Funds Encumbered:	**EPIC Funds Spent:**

$1,065,783	$1,140,254	
Partners: TBD		
Match Funding: TBD	**Match Funding split:** TBD	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: LB Monitoring Network • System Requirement Document drafted and completed. • Currently undergoing RFP process as additional information was requested from three vendors. Vendors are scheduled to present the demonstration and answer all project specific questions on 02/07/2017. Hybrid Poles • Vendor has been identified and a RFQ will be drafted and sent over by 02/03/2017. Underground RFI • Prototypes from 5 vendors have been procured in Q4 2016 and is currently undergoing testing. There is a possibility of a 6th vendor in upcoming weeks, however, all testing is expected to be completed by Q1 2017. High Impedance Fault Detection Following activities were accomplished during 2016 calendar year: • Enhanced system processes to accommodate lessons learn from various experiments; • Incorporated more advanced post processing algorithm utilizing variable windowing and thresholding to accurately identify discontinuities; • Designed prototype hardware and enclose to support extensive field testing; • Developed a SCADA interface to remotely control and monitor development hardware; and, • Expanded testing scenarios to include more complex and realistic circuit configurations.		

5. System Intelligence and Situational Awareness Capabilities

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution
Objective & Scope: This project will demonstrate system intelligence and situation awareness capabilities such as high impedance fault detection, intelligent alarming, predictive maintenance, and automated testing. This will be accomplished by integrating intelligent algorithms and advanced applications with the latest substation automation technologies, next generation control systems, latest breakthrough in substation equipment, sensing technology, and	

communications assisted protection schemes, This system will leverage the International Electrotechnical Commission (IEC) 61850 Automation Standard and will include cost saving technology such as process bus, peer to peer communications, and automated engineering and testing technology. This project will also inform complementary efforts at SCE aimed at meeting security and NERC CIP compliance requirements		
Deliverables: 1- Intelligent Alarm processing stake-holders lab demonstration 2- Testing tools lab demonstration and hand over to production team 3- Process bus lab demonstration		
Metrics: 2a. Hours worked in California and money spent in California for each project 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5a. Outage number, frequency and duration reductions 5e. Utility worker safety improvement and hazard exposure reduction 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 8e. Stakeholders attendance at workshops 8f. Technology transfer		
Schedule: Q1 2016- Q2 2018		
EPIC Funds Encumbered: $1,665,835	**EPIC Funds Spent:** $580,084	
Partners: TBD		
Match Funding: TBD	**Match Funding split:** TBD	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: This project explores three areas of improvement in system intelligence and situational awareness. The first area of focus is on operator consoles. Substation and system events are not always isolated to a single piece of equipment. One anomaly can cause what is sometimes called the Christmas tree effect in which operator screens are inundated by alarm triggered by a single event. The mass of alarms makes it difficult for operators to find the source of a problem and make critical operations decisions.		

The second area of focus is Substation testing. Testing is a critical part of installing a substation system. Existing testing practices require tedious, manual step-by-step processes that can be very time consuming. Adoption of new tools and methods that reduce testing time will be explored and demonstrated.

The third area of focus is demonstrating Process Bus technology. Advanced Technology (AT) is partnering with Engineering and Protection Automation Development to investigate IEC 61850 process bus technology to determine the feasibility of implementation on the SCE grid. Preliminary research by AT has shown there are many potential benefits but challenges in adopting the technology are significant. This project will investigate and test the conversion of existing hard-wired schemes to digital equivalents, in the areas of protection, automation, and configuration control. Additional benefits to systems engineering and testing will be explored. This project includes a laboratory demonstration of process bus technology.

2016 Milestone Achieved:

<u>Process Bus:</u>

- Technical Evaluation document has been developed
- Laboratory test planning has begun with input from Protection Automation Development (PAD)
- Held numerous meetings with vendors and utilities which are using or plan on using IEC 61850 Process Bus
- The SEL process bus equipment has been delivered to AT lab and testing has been started
- SEL Process bus has been installed on the rack and testing has started
- Continue to test process bus and learn valuable lessons on vendor (SEL, Siemens) implementations
- Optical CT vendor chosen. Lab unit to be acquired soon for testing
- Completed field conceptual design for optical CT installation

Intelligent Alarms:

- Held several internal kick off meetings which lead to the creation of the Project Outline document. The Project actual kick off scheduled for Q1 2017.

Substation Test Tools:

- Held several meetings with major Stake-holders
- New testing tool to improve the HMI PDI import has delivered to PAD

6. Regulatory Mandates: Submetering Enablement Demonstration - Phase 2

Investment Plan Period:	Assignment to value Chain:
2nd Triennial Plan (2015-2017)	Demand-Side Management

Objective & Scope:
This project expands on the submetering project from the first EPIC triennial investment plan cycle to demonstrate plug-in electric vehicle (PEV) submetering at multi-dwelling and commercial facilities. Specifically, the project will leverage 3rd party metering to conduct subtractive billing for various sites including those with multiple customers of record

Deliverables:

- Manual subtractive billing procedure for multiple customers of record
- 3PE final report
- PEV submetering protocol
- Final project report

Metrics:
1d. Number and percentage of customers on time variant or dynamic pricing tariffs
1h. Customer bill savings (dollars saved)
3e. Non-energy economic benefits
4a. GHG emissions reductions (MMTCO2e)
6a. The 3rd Party Evaluator, Nexant, in collaboration with the Energy Division and IOUs, will develop a set of metrics for Phase 2 to be included in the final report
7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving
technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360)
7j. Provide consumers with timely information and control options (PU Code § 8360)
7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)
8e. Stakeholders attendance at workshops
8f. Technology transfer
9c. EPIC project results referenced in regulatory proceedings and policy reports
9d. Successful project outcomes ready for use in California IOU grid (Path to market)
9e. Technologies available for sale in the market place (when known)

Schedule:
Q4 2015 – Q3 2018

EPIC Funds Encumbered:	EPIC Funds Spent:
$0	$300,450

Partners:
TBD

Match Funding:	Match Funding split:	Funding Mechanism:
TBD	TBD	Pay-for-Performance Contracts

Treatment of Intellectual Property:

SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: The project is in the final closeout stage and the final report has been completed. The project team is scheduled to present the results from the project to the stakeholders by February 2017, and will be ready undergo the closeout process. The project is under budget, and has been completed timely. Milestones achieved: • Requested and received CPUC's approval to extend the Phase 1 Pilot enrollment period six months. • Submitted Tier 1 Advice Letter to CPUC to update Phase 1 Pilot tariff due to Pilot extension. • Enrolled 92 SCE customers in the Pilot by end of extended enrollment period August 31, 2015. • Supporting 92 customers during their 12 month participation in the Phase 1 Pilot. Final Report for this project is attached.

7. Bulk System Restoration Under High Renewables Penetration

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Transmission
Objective & Scope: The Bulk System Restoration under High Renewable Penetration Project will evaluate system restoration plans following a blackout event under high penetration of wind and solar generation resources. Typically the entire restoration plan consists of three main stages; Black Start, System Stabilization, and load pick-up. The Project will be divided into two phases: * Phase I of the project will address the feasibility of new approaches to system restoration by reviewing the existing system restoration plans and it's suitability for higher penetration of renewable generation. It will include a suitable RTDS Bulk Power system to be used in the first stage of system restoration, black start and it will also include the modeling of wind and solar renewable resources. * Phase II of the project will focus on on-line evaluation of restoration plans using scenarios created using (RTDS) with hardware in the loop such as generation, transformer and transmission line protective relays. The RTDS is a well-known tool to assess and evaluate performance of protection and control equipment. This project intends to utilize the RTDS capabilities to evaluate and demonstrate system restoration strategies with variable renewable resources focusing on system stabilization and cold load pick-up. Furthermore alternate restoration scenarios will be investigated.	

After the restoration process is evaluated, tested, and demonstrated in the RTDS Lab environment, a recommendation will be provided to system operations and transmission planning for their inputs for further developing this approach into an actual operational tool.
Deliverables: TBD
Metrics: TBD
Schedule: TBD

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$0	$42,366

Partners: TBD

Match Funding:	**Match Funding split:**	**Funding Mechanism:**
TBD	TBD	Pay-for-Performance Contracts

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: In 2016, the team had numerous meetings both within the project team as well as with project stakeholders, sponsors, and advisors from SCE's Engineering, Planning, and Grid Operations groups to develop the detailed scope of work which culminated in the development of the Project Management Plan (PMP), which addresses the following. • A detailed Scope of Work statement • The project's work breakdown structure (WBS) and associated organization structure • The labor resource plan • A procurement plan that describes the materials and services that the project anticipates needing. • The project's milestone and deliverable schedule • The detailed project cost estimate Different equipment needed for Hardware in the loop testing was purchased. Also, transient models for solar PV and the system SVCs was modeled and tested. Due to organizational change within the group the project was canceled by Management.

8. Series Compensation for Load Flow Control

Investment Plan Period:	**Assignment to value Chain:**
2^{nd} Triennial Plan (2015-2017)	Transmission
Objective & Scope:	

The intent of this project is to demonstrate and deploy the use of Thyristor Controlled Series Capacitors (TCSC) for load flow control on series compensated transmission lines. On SCE's 500 kV system in particular, several long transmission lines are series compensated using fixed capacitor segments that do not support active control of power flow. The existing fixed series capacitors use solid state devices as a protection method and are called Thyristor Protected Series Capacitors (TPSC)		
Deliverables: • Project Cancelled		
Metrics: TBD		
Schedule: TBD		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $9,593	
Partners: TBD		
Match Funding: TBD	**Match Funding split:** TBD	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: A purchase order for the Controller Hardware replica for the Thyristor controlled series capacitor (TCSC) control system was about to be issued to Siemens. The project official starting date was to be January 2017. The work done in 2016 was mostly preparing the specification for the Controller Hardware replica and meetings with the vendors. However, it was determined internally by management that the deliverables for this project could easily be done via another project that was already well in flight, and so a determination was made to cancel this project.		

9. Versatile Plug-in Auxiliary Power System (VAPS)

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution
Objective & Scope: This project demonstrates the electrification of transportation and vocational loads that previously used internal combustion engines powered by petroleum fuels in the SCE fleet. The VAPS system uses automotive grade lithium ion battery technology (Chevrolet Volt and Ford Focus EV) which is also used in notable stationary energy storage projects (Tehachapi 32 MWh Storage)	
Deliverables: **Light Duty VAPS Platform – PHEV Pickup Truck:** Purchase Order for PHEV Truck, Test Result Report, Final Report	

Class 8 PHEV/BEV: Purchase Order for Class 8 PHEV/BEV, Test Result Report, Final Report
Medium Duty VAPS Platform – Class 5 PHEV 9ft. Flatbed: A Plug-in Hybrid Ford F550 Flatbed, Test Result Report, Final Report
Small, Medium and Large VAPS Systems: Purchase Order for Small VAPS, Year-end Report, Purchase Order for Medium/Large VAPS, Test Result Report, Final Project Report, New Fleet VAPS System Report

Metrics:
3a. Maintain/Reduce operations and maintenance costs
3e. Non-energy economic benefits
4a. GHG emissions reductions (MMTCO2e)
4b. Criteria air pollution emission reductions
5d. Public safety improvement and hazard exposure reduction
5e. Utility worker safety improvement and hazard exposure reduction
7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360)
8f. Technology transfer

Schedule:
Q3 2015 – Q1 2019

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$103,945	$227,473

Partners:
TBD

Match Funding:	**Match Funding split:**	**Funding Mechanism:**
TBD	TBD	Pay-for-Performance Contracts

Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.

Status Update:
A Request for Proposal (RFP) was sent to 4 qualified vendors to supply a Class 8 flatbed truck with VAPS type electric power system, and after extensive review, US Hybrid in Torrance CA was selected. They will provide a flatbed on an International platform in 2017, followed by lab test prior to beginning fleet demonstration. Efficient Drivetrain Inc. (EDI) was identified as the sole viable suppler that would be able to meet all specifications for a light duty PHEV truck with VAPS system. A base model Chevrolet Sierra 3500 was purchased and received, and the procurement process to send the vehicle for upfit to EDI was started. EDI will upfit the vehicle and evaluation will begin in 2017. EDI was also identified to be the sole supplier for a medium duty PHEV flatbed VAPS system. SCE worked with EDI to create the necessary specification and received quotes for the base Peterbilt chassis and the flatbed body upfit. The base vehicle, flatbed installation, and upfit will be performed in 2017.

For the small VAPS, the Altec Jobsite Energy Management System (JEMS) installed on a F550 Troubleman truck was received and performance testing was started. SCE requested and received from Altec a quote to install the JEMS 4A systems on F150 field service vehicles but the system did not meet all specifications and safety requirements. SCE is working with Altec to further refine the system to meet the requirements. A JEMS 4A base system was purchased and received to perform bench testing and long term evaluation testing. For the medium VAPS, SCE worked with Envoltz Inc. to evaluate a fully electric underground cable puller with VAPS type Li-ion battery system both in the lab and at two field demonstrations. The unit performed as designed and was well received by field crews. An order for one unit was placed and it will be demonstrated by multiple crews throughout SCE in 2017. A total of 44 remote data acquisition systems were purchased from FleetCarma to be placed on multiple electrified platforms to collect data from the demonstrations. The systems will be installed in 2017 and track vehicle usage for one year.

10. Dynamic Power Conditioner

<table>
<tr><td>Investment Plan Period:
2nd Triennial Plan (2015-2017)</td><td colspan="2">Assignment to value Chain:
Distribution</td></tr>
<tr><td colspan="3">Objective & Scope:
This project will demonstrate the use of the latest advances in power electronics and energy storage devices and controls to provide dynamic phase balancing as well as providing voltage control, harmonics cancellation, sag mitigation, and power factor control while providing steady state operations such as injection and absorption of real and reactive power under scheduled duty cycles or external triggers. This project aims to mitigate the cause of high neutral currents and provide several power quality benefits through the use of actively controlled real and reactive power injection and absorption</td></tr>
<tr><td colspan="3">Deliverables:
TBD</td></tr>
<tr><td colspan="3">Metrics:
TBD</td></tr>
<tr><td colspan="3">Schedule:
TBD</td></tr>
<tr><td>EPIC Funds Encumbered:
$0</td><td colspan="2">EPIC Funds Spent:
$13,166</td></tr>
<tr><td colspan="3">Partners:
TBD</td></tr>
<tr><td>Match Funding:
TBD</td><td>Match Funding split:
TBD</td><td>Funding Mechanism:
Pay-for-Performance Contracts</td></tr>
<tr><td colspan="3">Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="3">Status Update:</td></tr>
</table>

For 2016, the Dynamic Power Conditioner (DPC) activities included speaking with several vendors to understand the current state of their technology and possible system offering for the Energy Storage System (ESS) community. The team has also been discussing with other possible power conversion system (PCS) vendors to get a more in-depth understanding of their upcoming PCS applications and roadmap. Along with understanding the current state of the market we have also been working on developing the technical requirements and SOW for our upcoming RFI and RFP.

11. Optimized Control of Multiple Storage Systems

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution	
Objective & Scope: This project aims to demonstrate the ability of multiple energy storage controllers to integrate with SCE's Distribution Management System (DMS) and other decision making engines to realize optimum dispatch of real and reactive power based on grid needs		
Deliverables: TBD		
Metrics: TBD		
Schedule: TBD		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $2,565	
Partners: TBD		
Match Funding: TBD	**Match Funding split:** TBD	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: In 2016, the Optimized Control of Multiple Storage Systems project continues to evaluate the requirements and the integration of multiple control strategies to optimize multiple energy storage scenarios. This projects looks to unlock the hidden benefits of having the ability of to demonstrate multiple energy storage controllers that will support the Integrated Grid Project and the SCE's Energy Storage Ownership Initiative (ESOI).		

12. DC Fast Charging Demonstration

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Demand-Side Management

Objective & Scope:
The goal of this project is to demonstrate public DC fast charging stations at SCE facilities near freeways in optimal locations to benefit electric vehicle miles traveled (eVMT) by plug-in electric vehicles (PEVs) while implementing smart grid equipment and techniques to minimize system impact. The Transportation Electrification (TE) Organization is actively pursuing several strategic objectives, including optimizing TE fueling from the grid to improve asset utilization. Deploying a limited number of fast charging stations at selected SCE facilities that are already equipped to deliver power at this level (without additional infrastructure upgrade) will support this objective. The project will leverage SCE's vast service territory and its facilities to help PEV reach destinations that would otherwise be out-of-range

Deliverables:
Final Report

Metrics:
3a. Maintain/Reduce operations and maintenance costs
5b. Electric system power flow congestion reduction
5h. Reduction in system harmonics
8d. Number of information sharing forums held
8e. Stakeholders attendance at workshops
8f. Technology transfer

Schedule:
Q1 2016 – Q2 2017

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$0	$10,870

Partners:
TBD

Match Funding:	**Match Funding split:**	**Funding Mechanism:**
TBD	TBD	Pay-for-Performance Contracts

Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.

Status Update:
Planning was completed in Q1 2016. In order to demonstrate the feasibility and effectiveness of installing fast charging stations, initial planning was focused on assessing the impact of existing fast charging stations on the electric distribution system. A team of experts was assembled within SCE, and power quality monitoring equipment has been specified and purchased to instrument approximately 16 stations and collect data simultaneously. A schedule has been created to study 25 stations in SCE's territory. The installation of data logging equipment has begun, and the first site is instrumented and collecting data. Tesla's Buena Park Supercharger Station came online in Q4 2016 in conjunction with project monitoring, which allowed for some special tests to be performed in conjunction with Tesla. SCE is now coordinating efforts to install the remaining data

logging equipment and get telemetry up and running for remote data acquisition. The installation of all 16 stations is estimated to be completed in Q2 of 2017, and then upon completion of assessment, additional stations will be instrumented and studied. The final analysis and report will be completed in late 2017. A preliminary system impact study of the Buena Park site was completed in Q4 2016 by SCE. The results are under review among SCE's experts to assess the information contained in the study.

13. Integrated Grid Project II

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Cross-Cutting/Foundational Strategies & Technologies
Objective & Scope: The project will deploy, field test and measure innovative technologies that emerge from the design phase of the Integrated Grid Project (IGP) that address the impacts of DER (Distributed Energy Resources) owned by both 3rd parties and the utility. The objectives are to demonstrate the next generation grid infrastructure that manages, operates, and optimizes the distributed energy resources on SCE's system. The results will help determine the controls and protocols needed to manage DER, how to optimally manage an integrated distribution system to provide safe, reliable, affordable service and also how to validate locational value of DERs and understand impacts to future utility investments.	
Deliverables: • Evaluation of systems performance and field operations performance • Report on market maturity of technologies demonstrated • Final project report (Phase 2)	
Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 1h. Customer bill savings (dollars saved) 1i. Nameplate capacity (MW) of grid-connected energy storage 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 3e. Non-energy economic benefits	

3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management
5a. Outage number, frequency and duration reductions
5b. Electric system power flow congestion reduction
5c. Forecast accuracy improvement
5f. Reduced flicker and other power quality differences
5i. Increase in the number of nodes in the power system at monitoring points
7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360);
7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360);
7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360);
7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360);
7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360);
7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360);
7j. Provide consumers with timely information and control options (PU Code § 8360);
7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360);
7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)
8b. Number of reports and fact sheets published online
8d. Number of information sharing forums held.
8f. Technology transfer
9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs
9c. EPIC project results referenced in regulatory proceedings and policy reports.
9d. Successful project outcomes ready for use in California IOU grid (Path to market).

Schedule:
Q3 2016 - Q4 2018

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$7,274,568	$1,638,736

Partners:
TBD

Match Funding:	**Match Funding split:**	**Funding Mechanism:**
TBD	TBD	Pay-for-Performance Contracts

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: In 2016, the Integrated Grid Project (IGP) executed the RFP packages, contract awards, and the final procurements for core project elements including the control systems, integration bus, and the software required for lab testing. The following EPIC II activities were completed by the project team in 2016: • Completed initial RFP packages • Negotiated and awarded contracts to vendors • Received the controller software from vendors • Received the UIB (Utility Integration Bus) software • Received the lab test software

5. Conclusion

a) Key Results for the Year for SCE's EPIC Program

(1) 2012-2014 Investment Plan

For the period between January 1 and December 31, 2016, SCE expended a total of $15,617,728 toward project costs and ($35,963) toward administrative costs for a grand total of $15,581,765. SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC program amount to $31,313,240. SCE committed $37,755,476 toward projects and encumbered $23,146,836 through executed purchase orders during this period.

SCE continued project execution activities towards the approved portfolio of 16 projects; 4 of these projects were completed during the calendar year 2016. The list of completed 2012-2014 Investment Plan projects include: 1) Enhanced Infrastructure Technology Report; 2) Submetering Enablement Demonstration; 3) Dynamic Line Rating; and 4) Distribution Planning Tool. SCE has completed final project reports for these 4 projects and included them in the Appendix of this annual report.

(2) 2015-2017 Investment Plan

For the period between January 1 and December 31, 2016, SCE expended a total of $4,950,128 toward project costs and $770,601 toward administrative costs for a grand total of $5,720,729. SCE's cumulative expenses over the lifespan of its 2015 – 2017 EPIC program amount to $6,284,109. SCE committed $36,797,917 toward projects and encumbered $12,096,976 through executed purchase orders during this period.

SCE launched 12 projects during the calendar year 2016. All 12 projects received funding commitments through SCE's Advanced Technology portfolio management process.

b) Next Steps for EPIC Investment Plan (stakeholder workshops etc.)

During the calendar year 2017, SCE will continue to focus on successfully executing its remaining 9 approved projects as part of its 2012 – 2014 Investment Plan, and 11 approved projects as part of its 2015 – 2017 Investment Plan. Key program implementation activities will include finalizing demonstration plans and requirement specifications, initiating new procurements, continuing technology deployments in SCE's field and lab environments, and executing rigorous testing, measurement, and verification processes.

Furthermore, SCE will continue its open dialogue with stakeholders through two planned workshops in 2017. In these workshops, SCE and the other EPIC Administrators will provide stakeholders with an update on key accomplishments and learnings obtained from their respective EPIC programs. In addition, SCE will discuss the initiatives and proposed project activities that are being considered as part of the EPIC III investment planning process. The EPIC III Application will be filed on May 1, 2017.

c) Issues That May Have Major Impact on Progress in Projects

SCE manages its EPIC program through a structured and highly disciplined portfolio management governance framework. As part of this portfolio management process, SCE performs a critical assessment of all projects on a quarterly basis to A) review the financial and schedule status of EPIC projects vis-à-vis baselined project management plans; and, B) review the technical viability, value proposition and deployment readiness for each EPIC project in light of changing market and industry dynamics.

Given the volatility that characterizes new smart grid technologies, particularly for those in the pre-commercial stage, SCE works to help ensure that its portfolio management process incorporates a real-time feedback loop to address late-breaking market developments and information. Furthermore, the launching of new corporate or regulatory initiatives[32] after an investment plan has been approved by the Commission may warrant updates to certain EPIC projects as well. As a result of this process, SCE may find it prudent to enhance, revise, or cancel projects in order to accommodate and adapt to emergent regulatory directives or new industry guidance on specific technologies.

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[32] The CPUC's Distribution Resources Plan is one example.

Appendix A

Advanced Technology Distribution Market Demonstration and Analysis

Final Project Report

Advanced Technology
Distribution Market Demonstration and Analysis
Final Project Report

Developed by

SCE Transmission & Distribution, Advanced Technology Organization

Disclaimer

Acknowledgments

Prepared for:

Customer name and Address

Prepared by:

Principle Investigators (s)

Change Log

Version	Date	Description of Change	Project Report No.
0.3	02/14/2017	Sub-project Consolidation	
0.4	02/14/2017	Former PM review/EPIC Manager Review	

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Preface

1 Executive Summary

SCE, in its recently released whitepaper "The Emerging Clean Energy Economy," outlined a vision to accelerate the transition to a clean, reliable energy future that includes a high penetration of distribution energy resources (DERs), by facilitating customer choice of new technologies, creating opportunities for DERs to provide grid services, and modernizing the grid to ease integration and optimization of DERs.

As customers connect increasing amounts of DERs to the electric grid, the grid has been rapidly evolving. However, in order to facilitate and accommodate a high penetration of DERs, a modernized grid is needed, both technically and business-wise.

On one hand, a modernized grid needs to support multi-directional power flows from these DERs, while being resilient enough to mitigate voltage and power quality issues resulting from these DERs. To facilitate the design and planning of this evolving grid, SCE has identified the need for new advanced distribution circuit modeling tools as a necessary foundational technology solution. SCE leveraged EPIC funds allocated to Distribution Planning Tool project to conduct two sub-projects that have related objectives. The first sub-project focused on developing advanced modeling functions by leveraging GridLAB-D, an open-source research simulation software with the ability to model behind-the-meter resources and demands, created by the U.S. Department of Energy's Pacific Northwest National Lab, GridLABD (GLD). SCE contracted, Battelle, a non-profit, Federally Funded Research and Development Corporation (FFRDC), to develop new GLD modules and to assist SCE with developing new distribution models.

This sub-project was partially successful with Battelle completing approximately 50% of the planned work. In total, Battelle developed four of the originally 8 planned GLD modules and assisted SCE with successfully developing 30 distribution models. The original project scope called for Battelle to define, implement and validate 8 new GLD modules, enhance SCE's 'CYME to GLD' conversion tool and to support SCE with developing 30 GLD distribution models.

The GLD modules that were completed include:

- Commercial module capable of simulating commercial loads and commercial demand response
- Valuation framework to calculate locational value of DERs
- Enhancements to Energy Storage module
- Enhancements to Electric Vehicle module.

The planned features that were not developed included:

- Volt/VAR module
- Advanced inverter modules
- Cloud cover modules
- Modified Market Module,
- Energy Management System/ Distributed Resource Energy Management System, (EMS/DREMS).

Of the four modules developed, only the Commercial module was validated. The validation results show that the Commercial model predicts monthly usage to within 20% of actual usage. SCE validated the demand response portion of the Commercial module and results show that the demand response function performs poorly and is not currently suitable for planning purposes. The other modules, the Valuation Framework, Energy Storage and Electric Vehicle were not validated.

Both technical and human resource issues negatively affected the outcome of this project. The development of some modules proved more technically challenging than originally anticipated, resulting in project delays. SCE ultimately terminated the contact with Battelle after the lead developer, working on this project, resigned from Batelle. SCE concluded that the risk of the remaining portions of the sub-project not be properly implemented was too great.

The valuation pipeline tool can help to develop incentive structures that would compensate customers based on the locational value of their DER. This also supports the legislative requirement in AB 327 to capture the locational values of DERs. The Electric Vehicle and Energy Storage modules will also help to enhance planning capabilities by simulating more realistic charging schedules. The 30 distribution models have already provided value as they were used in a core research project to study the impacts of high PV penetration and to determine the optimal set of mitigation strategies to enable 100% PV penetration using representative circuits used in the research study.

On the other hand, a modernized grid also needs to provide transparent information for customers to understand the system condition and their options for easy and economic DER adoption and development. SCE has identified the need of sharing the hosting capacity information to the public for this purpose.

In this second sub-project, SCE demonstrated a fully dynamic DER hosting capacity analysis which would determine the hosting capacities at circuit nodes based on limiting categories of thermal rating, power quality and voltage criteria, protection coordination requirements, safety and reliability, as well as substation limitations. The demonstration evaluated two different methodologies using the existing distribution planning tool CYMDIST but with newly developed function modules, within two distinct distribution planning areas and under various power flow scenarios and loading conditions.

The first methodology, referred to as the Streamlined Method, was to perform one power flow simulation for each scenario and then extract quantities from the power flow simulation and insert them into the streamlined equations to determine the hosting capacities for each of the limiting categories. The second methodology, referred to as the Iterative Method, was to utilize iterative power flow simulations to determine the hosting capacities for each of the limiting categories. Considering the balance of accuracy of results and computational time requirements, SCE proposed a Blended Method for initial implementation of hosting capacity calculations across the SCE service territory. This method would use the Iterative Method on the typical 24-hour, light-load day in an annual period, which yields the necessary information required under the existing Rule 21 process, while developing a full 576 hourly (typical high load day and typical light load day for each month) calculation utilizing the Streamlined Method to provide information for planning purposes.

This sub-project successfully implemented all the planned tasks including area selection, model development, methodology implementation and simulations. The hosting capacity results, which indicated the maximum amount of DERs that can be connected without adversely impacting SCE's distribution system functions, were published on SCE's Distributed Energy Resource Interconnection Map (DERiM) to share with the public.

In this EPIC project, the tools developed under the first sub-project will provide great value by informing SCE's future investments towards a modernized grid, the methodologies demonstrated in the second sub-project will provide valuable information for both customers and planning engineers to move towards a grid with a high penetration of DERs. More immediately, these capabilities can help to satisfy regulatory requirements for utilities to identify locational net benefit of DERs, incorporate DERs into grid planning activities and support demonstration projects such as the Integrated Grid Project which satisfies requirements under the Distribution Resource Plan (DRP) Demo D.

2 Sub-project 1: Distribution Planning Tool

2.1 Project Summary

This project involves the development and validation of advanced modeling capabilities necessary for the planning of the future distribution system. SCE contracted Battelle to develop new capabilities within GLD, develop an export tool from Cyme to GLD, and assist SCE in developing 30 distribution models.

2.1.1 Project Objective

The primary goal of this project was to develop advanced modeling capabilities and distribution models necessary to inform SCE's future distribution system. To achieve this goal, SCE contracted Battelle, a non-profit, Federally Funded Research and Development Corporation (FFRDC), to modify and enhance the existing GLD software. SCE developed a list of 8 core functional requirements to be developed under this project. Additionally, the project involved the development of 30 distribution circuit models in GLD format and a tool to convert Cyme models to GLD.

The capabilities to be developed under this project included (1) a framework to determine true cost of DERs (2) a module to simulate SCE specific Commercial customer loads and demand response (3) enhancements to the Energy Storage module, (4) improvements to the Electric Vehicle module, (5) implementation of a SCE specific Volt/VAR scheme, (6) a Distributed Energy Resource Managing System to coordinate all DER functions, (7) an asynchronous Cloud cover module and others, and (8) revisions to the demand response functions to include SCE specific Demand Response programs.

2.1.2 Problem Statement

The electric industry is being transformed due to advances in technology; regulatory requirements and increased customer demand for choice. The success of this transformation will depend largely on the distribution planning tools available to that will inform this new grid. There are currently large gaps between the modelling capabilities available in the electric industry today and those that are needed to help plan this future grid. This project seeks to bridge some of these gaps by identifying and implementing new functionalities within the existing open source power simulation tool, GLD. Some of these new functionalities were guided by regulatory requirements under AB 327, such as the development of a framework to help determine the locational net benefit of DERs.

2.1.3 Scope

Originally the project scope involved only the services defined under the Phase 1 scope and this included the development and validation of 8 GLD modules, a 'CYME to GLD' conversion tool and support services to help SCE develop GLD distribution models. Approximately 6 months into the project, a new project phase was developed, the 2nd project phase, to align with SCE's changing priorities and due to some of technical difficulties with the development of some modules. Three of the modules scheduled for phase 1 were moved into phase 2. Below is a summary of the scope of works defined under both phases.

<u>Phase 1 Scope:</u>

Phase 1 tasks represent the total scope as defined at the start of the project. The three main tasks are:

1) Define, implement and validate 8 new modules within GLD. Below is a listing of these modules.
    - Commercial & Industrial Load Models

- Advanced Inverter Module
- Electric Vehicle Charger Module
- Energy Storage Module
- Market Module (Demand Response)
- Solar Irradiance Module (Cloud Cover)
- Volt/VAR module
- Distributed Energy Renewable Management System (DERMS)

2) Enhance SCE's 'CYME to GLD' conversion tool to include features
3) Support SCE with model building and fix bugs that SCE may encounter while building the distribution models.

Phase 2 Scope:

The 2nd phase was developed, during the phase 1 execution stage, to capture some of the challenges and changing priorities of the project. Three of the four modules defined in the 2nd phase were originally to be developed during the 1st phase. The main tasks included in the 2nd phase are:

1) Define, implement and validate 4 new modules within GLD. These include:
    - Solar Irradiance Module (From 1st phase)
    - Volt/VAR module (From 1st phase)
    - Distributed Energy Renewable Management System (From 1st phase)
    - Valuation Pipeline Framework (New in 2nd phase)
2) PV adoption script which places new PV devices at locations based on a PV adoption methodology.

2.1.3.1 Phase 1 & 2 Module Description:

Below is a brief description of each planned module:

2.1.3.1.1 Commercial & Industrial Load Models

The purpose of the Commercial module is to model SCE specific commercial load types and to enable demand response simulations on the HVAC components of the commercial loads. GLD has built in capability to model residential homes, which are generally single zone buildings between 500 and 4000 sq. ft, and the major devices within the homes such as HVAC, ovens, water heaters, pool pumps. There was no module available, capable of modeling and simulating commercial buildings which are multi-zonal and diverse in size and business functions. The Commercial module was built to fill this gap. This module should simulate SCE specific commercial loads and HVAC demand response.

2.1.3.1.2 Volt-VAR Control Module

The Volt-VAR module is a control algorithm that simulates the Distributed Volt/VAR control system currently in operation at SCE. It attempts to minimize average circuit voltage while ensuring that voltages, as measured throughout a circuit, remain within specified limits. The AVVC module will be designed to execute optimization both at regular intervals and in the event that measured voltage is outside set limits. As part of the optimization procedure, the module will attempt to find capacitor switching configurations that minimize both voltage and reactive power while ensuring that both remain within set limits. The module will also have the ability to detect which capacitors are available for use in optimization at execution time, to flag unresponsive or poorly-performing capacitors as failed, and to determine if previously failed capacitors are functional again.

2.1.3.1.3 Advanced Inverter Module

The existing inverter module in GLD would be extended to include additional smart capabilities. Some of these capabilities include:

- Adjusted power factor control based upon PCC voltage
- Adjusted power factor control based on time of day
- Adjusted power factor control based on predetermined modes for the day (eg a once a day SCE control system communicates with the inverter to notify of weather conditions)
- Inverter control communications based upon a delay setting (eg 1 minute).
- Develop, Implement, Test, Validate and Refine support for the “FOUR_QUADRANT” inverter type and control modes “CONSTANT_PQ” and “VOLT_VAR”

2.1.3.1.4 Electric Vehicle Charger Module

The existing Electric Vehicle module would be enhanced to allow more flexible schedules. In the standard build of GLD the schedules of EV usage defined by the user is equally applied to all seven days of the week. Changes to the module would allow for more flexible scheduling so that more realistic usage patterns could be applied to the electric vehicle usage.

2.1.3.1.5 Market Module (Demand Response)

The existing Market Module would be enhanced to simulate SCE specific Demand Response Programs and to add functionality that would incorporate wholesale market prices and behavior to devices.

2.1.3.1.6 Energy Storage

The existing Electric Storage module would be enhanced to include (1) a MW size (Sodium Sulfur – NaS) battery object, (2) a Community Energy Storage (CES) controller object which coordinates operation of multiple energy storage devices and (3) enhanced inverter object which includes 4 quadrant controls. The CES controller coordinates energy storage devices to achieve (1) peak shaving, (2) load following, and (3) islanding functions

2.1.3.1.7 Solar irradiation stochastic variance (cloud cover)

The Solar Irradiance module would simulate the effects of cloud cover by varying the irradiance detected by nearby PV objects on the same circuit. The standard version of GLD does not support this. Some of the new features include:

- Turn the stochastic feature on/off
- Set bandwidth for variance
- SCE would analyze/provide irradiance data

2.1.3.1.8 EMS/DERMS

An Energy Management System (EMS)/Distributed Energy Resource Management System (DERMS) module would model a central control mechanism to optimize the usage of multiple DER resources based on a user defined objective function. The objects to be controlled by the DERMS include (1) photovoltaic (PV) inverters, (2) Energy Storage device controllers, (3) Electric Vehicle Chargers, and (4) demand response of residential and commercial HVAC and pool systems.

The DERMS module coordinates the behavior of the subsystems to achieve system-wide goals, possibly by modifying or overriding independent goals of the individual subsystems. Upgrades would be made to the DER classes (PV, Demand Response, Electric Vehicle and Energy Storage) to enable participation with the DERMS during simulation. The DERMS would have the following characteristics.

- An independent objective function
- A scheduling feature
- A list of points to monitor to use for its state estimation
- A generic stochastic failure of communication

2.1.3.1.9 VALUATION PIPELINE:

The Valuation Pipeline framework is needed to help understand the true cost of installing technology on the circuit. It performs a cost-benefit analysis from installing technologies to the circuit and it evaluates cost from the perspective of the customer, utility and society.

The technologies included are energy storage, demand response (HVAC & pool pumps), renewable generation (specifically solar PV), electric vehicles, and conservation voltage reduction (utility controlled capacitors). The tasks to develop the tool include the following:

- Modification of GridCommand Distribution
- Apply organized recorder methodology to track relevant simulation values

2.1.3.2 Phase 1 CYME import tool

This task would make improvements to a 'CYME to GLD' conversion tool originally developed by SCE. SCE's conversion tool does not currently model line capacitance and cannot handle single-phase center tapped transformers. Battelle was tasked with implementing these features and also make changes ensuring that CYME spot loads can be validated against GLD loads.

2.1.3.3 Phase 2: Scripting Services

The Scripts to be developed will accomplish the following functions:

- Distribute solar to house and commercial objects based on usage bin parameter and inputs from SCE PV Adoption model
- Distribute EVs and PHEVs in a similar method to Solar PV, with SCE forecasts as input
- Distribute Energy Storage based on total installed capacity

2.1.4 Schedule

The initial project schedule involved the development of eight modules to be completed within 8 months. The project commenced in May 2014 and was scheduled to be completed by the end of Jan 2015. At the end of January, only the EV Charger and the Energy Storage modules were completed while the Commercial Model was still being developed. Due to the project delays and shifting priorities a 2nd phase of the project was implemented in the early part of 2015. The scheduled tasks for Phase 1 and Phase 2 of the project are shown in Tables 1 and 2 below respectively.

Table 1: First Phase Project Schedule (9/19/14)

Updated Schedule of tasks as of (9/18/14)				
#	Task	Duration (Days)	Start Date	End Date
1	Kickoff meeting	3	5/12/2014	5/14/2014
2	Commercial Model	105	5/19/2014	10/10/2014
3	EV Charger	73	6/16/2014	9/24/2014
4	Energy Storage	73	6/16/2014	9/24/2014
5	Commerical Demand Response	40	9/15/2014	11/7/2014
6	Cloud Cover	41	10/10/2014	12/5/2014
7	Solar PV Inverter (enhanced)	30	10/24/2014	12/4/2014
8	Generic Residential Demand Response	46	10/17/2014	12/19/2014
9	Volt VAR Control	56	9/26/2014	12/12/2014
10	EMS/DERMS	80	9/19/2014	1/8/2014
11	Monthly Reports	155	6/30/2014	1/30/2014

Table 2: Second Phase Project Schedule

Phase 2 Schedule		
#	Task	Duration (Days)
1	EMS/DERMS	120
2	Volt VAR Control	90
3	Cloud Cover	30
4	Valuation Pipeline	120
5	Scripting Support	Duration of project

2.1.5 Milestones and Deliverables

Battelle was required to provide a document defining module functionality, source code, and Validation results for each module developed. Table 3 below shows the final status of the planned modules and table 4 shows the milestones of the supporting tasks.

Table 3: Module Development Status

Milestone/Deliverables (Module Development)	Source Code	Requirement Document	Validation	Project Phase
Commercial Model with Demand Response	Complete	Complete	Complete	1,2
EV Charger	Complete	Complete	Incomplete	1
Energy Storage	Complete	Complete	Incomplete	1
Valuation Pipeline	Complete	Complete	Incomplete	2
Volt VAR Control	Incomplete	Complete	Incomplete	1,2
EMS/DERMS	Incomplete	Complete	Incomplete	2
Cloud Cover	Incomplete	Incomplete	Incomplete	1
Solar PV Inverter (enhanced)	Incomplete	Incomplete	Incomplete	1
Generic Residential Demand Response	Incomplete	Incomplete	Incomplete	1

Table 4: Additional Tasks Status

Milestone/Deliverables (Additional Services)	Status	Project Phase
Training on new and existing GridLABD modules	Complete	1,2
Scripting Services for distribution model buidling	Complete	1,2
General support for SCE distribution model building efforts	Complete	1,2
Import Tool from Cyme to GridLAB-D	Incomplete	1
Fix Bugs encountered by SCE modeling effort	Complete	1,2

Much of the originally planned project scope was not completed. In total only four of eight planned modules were implemented with only one of these, the Commercial module, also being validated. The remaining four modules were either not completed or cancelled during the course of the project. There were unforeseen difficulties with the development of some modules, especially the Commercial module, and this resulted additional time being spent on these modules and thus other modules could not be developed.

The contract with Battelle was based on the “time” spent on the project. Both SCE and Battelle acknowledged that all the works may not be completed within the planned schedule due to uncertainties regarding the exact amount of time that would be needed. The project was ultimately cut short and cancelled after one of the key developers working on the project had resigned from Battelle.

2.2 Test Set-Up/Procedure

Battelle wrote specification documents defining the various functionalities and features to be included in each module. Battelle then wrote software code to implement the modules in GLD. Below is a description of the functions, features and methods used to develop the four completed GLD modules and a description of the additional tasks performed by Battelle.

2.2.1 Commercial Module Development and Validation

The Commercial module was developed to simulate SCE commercial loads and demand response events. It consists of two major components. The first component is a model of the building’s HVAC system and the second component is a model of the commercial customer’s load profile due to their typical business processes and HVAC. The Implementation procedure of these two components is described below

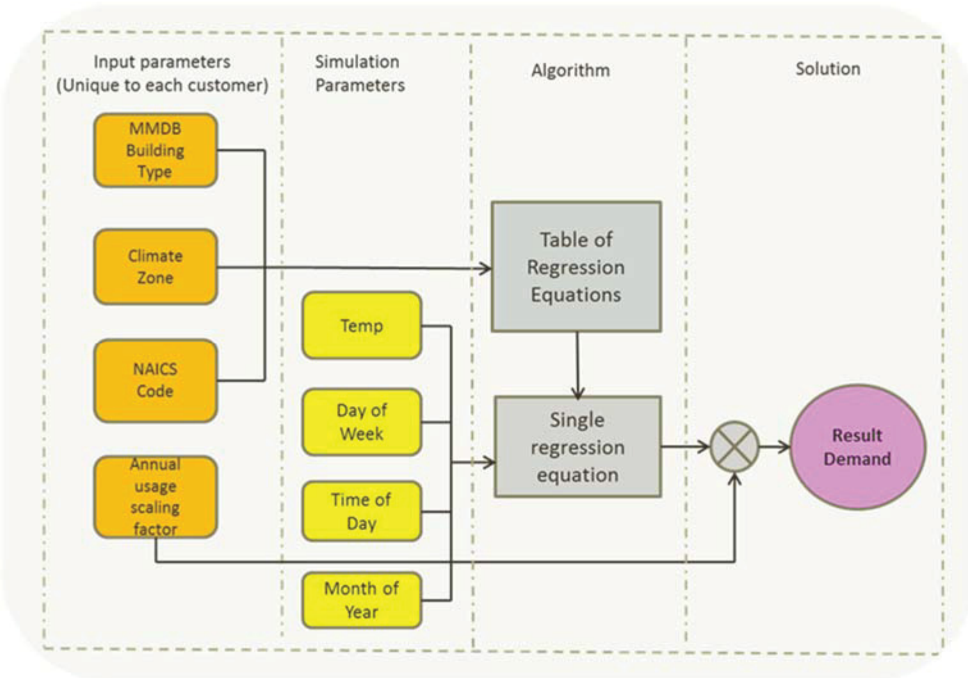
Commercial load component:

The underlying behavior of the Commercial Load Module is governed by a regression equation that considers the customer’s building type, climate zone, North American Industry Classification System (NAICS) code, and average daily energy usage, as well as the current date, time, and outdoor temperature to compute a load value. The building type, climate zone, and NAICS code are used to select a set of coefficients that describe the time- and temperature-dependent behavior of the customer’s load. The average daily usage serves to scale the calculated load value. SCE provided Battelle with masked customer historical usage and AMI data along with other customer characteristics such as the customer’s NAICS code and the climate zone they are situated in.

The major steps to create the commercial models involved (1) defining 33 Building types and map each of the North American Industry Classification System (NAICS) code to one of the 33 Building Types, (2) groups customers into cohorts based on similar characteristics (Building Type, North American Industry Classification System (NAICS) code and Climate Zone and (3) perform a regression on each cohort using historical customer usage data, to build a statistical model that predicts the customer's scaled usage based on Temperature, Hour of the Day, Day of the Week and Month of the Year

To run the model, the user enters the customer's Building Type, NAICS, Climate zone and average annual usage. A set of regression coefficients is then selected and the customer's demand is calculated, at each time step, as the solution to the regression equation.

Figure 1: Commercial Module Process Flow



Commercial HVAC Demand Response Component:

The ultimate goal of the commercial module was to simulate demand response events on the HVAC component of the commercial load. Battelle's initial approach was to model a simplified HVAC system using a set of differential equations that models energy exchange between the HVAC and the outside of the building. This model did not perform well. Battelle then attempted a more simplified method using the temperature dependent nature of loads to affect change by simply adjusting the outside temperature during a demand response event. This method also did not provide good results.

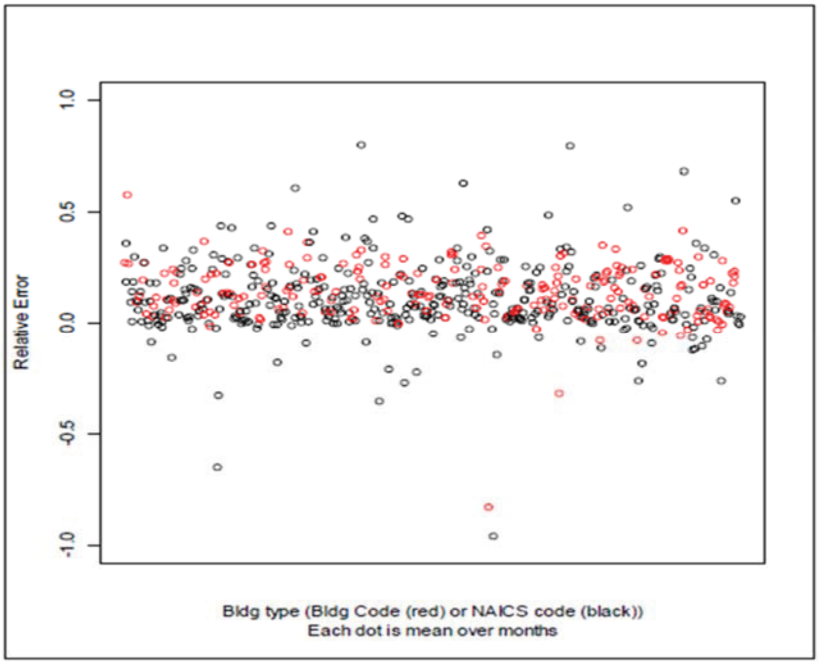
Table 5: Commercial Building Types

ID	MMDB-Building Type
1	Agricultural
2	Assembly
3	Education - Primary School
4	Education - Secondary School
6	Education - Community College
7	Education - University
8	Grocery
9	Food Store
10	Health/Medical - Hospital
11	Health/Medical - Nursing Home
12	Health/Medical - Clinic
13	Lodging - Hotel
14	Lodging - Guest Rooms
15	Lodging - Motel
17	Manufacturing - Light Industrial
18	Industrial
19	Misc. Commercial
20	Office - Large
21	Office - Small
23	Residential - Multifamily
25	Restaurant - Fast-Food
26	Restaurant - Sit-Down
27	Retail - Multistory Large
28	Retail - Single-Story Large
29	Retail - Small
31	Storage - Unconditioned
32	Transportation - Communication - Utilities
33	Warehouse - Refrigerated

Commercial Module –Validation (Load model component):

Battelle validated the module's ability to model usage. Actual monthly usage data was compared against the predicted hourly data for the same month and the same ambient temperature profile for that month. Figure 2 below shows the results of this prediction with the y axis representing the relative error. The model is over predicting usage generally below 30%

Figure 2: Commercial Load Model Validation Results



Note: The y axis shows the relative error. The error is generally below 30%

Commercial Module – Validation (Demand Response Component[AV1]):

As part of a CSI high PV penetration study, SCE considered traditional demand response to mitigate the impact of high solar PV penetration. SCE intended to utilize the commercial modules developed by Battelle to simulate commercial demand response events. However, unlike the residential load modules which are fully developed, the result of the validation performed as part of this effort showed the new GridLAB-D commercial models developed by Battelle are not ready to accurately simulate commercial demand response events to assess demand response potential of temperature sensitive loads mainly HVAC systems. The team heavily leveraged AMI data to develop the modules used in the study; more detailed data about commercial load are needed to develop more accurate commercial models.

In addition, the study showed traditional demand responses is not well suited to mitigate the vast majority of operational violations which involve high voltage conditions during periods of high solar. This can be exacerbated by the reduction of load which also has the effect of raising voltage across the circuit. Under these conditions, what would be required is a demand response scheme that incentivizes load to turn *on*; or directly energizes load through a direct load control system. Therefore, the commercial module further development work need to ensure capability is built in the commercial modules to simulate turning load on contrary to traditional demand response schemes which are designed to reduce load.

2.2.2 Energy Storage Module Enhancements

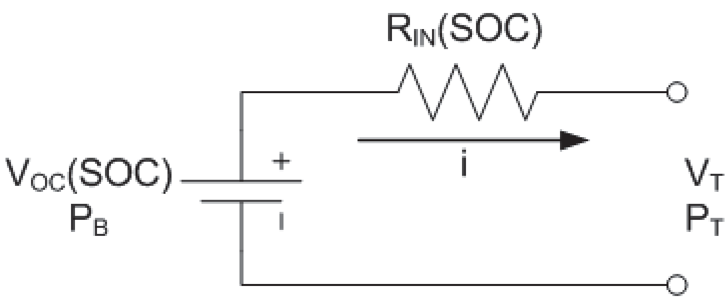
Battelle implemented new features enhancing the capabilities of the existing Energy Storage module. These features include (1) a MW size (Sodium Sulfur – NaS) battery object, (2) a Community Energy Storage (CES) controller object which coordinates operation of multiple energy storage devices and (3) enhanced inverter object which includes 4 quadrant controls.

Inverter Object:

One of the most significant updates to the inverter object was the inclusion of four quadrant control, which is upgraded from the previous single quadrant control, which provided only real power. A four quadrant inverter can provide power across all four quadrants of the power unit circle, which allows the inverter to supply or sink real power while also providing positive or negative reactive power support to the electric grid. These updates allow the inverter to function with the updates to the battery object, and to accommodate the control functionality required by NaS and CES.

Sodium Sulfur (NaS) object:

The battery object in GLD was updated to support the electrical and chemical characteristics of the NaS battery type. The battery object uses a simple model to simulate the battery losses by taking into account the internal resistance and the voltage curve with respect to state of charge (SOC). Parameters provided by the user along with the characteristics of the battery type are used to calculate the internal efficiency of the battery. The round trip efficiency is used to determine an internal efficiency based on the open circuit voltage (V_{OC}) curve of the battery. The simplified circuit used in the battery object to represent the efficiency of the battery is shown in **Error! Reference source not found.**.



For each battery type, there is a specific voltage vs. SOC curve. Using this curve, as well as a specified round trip efficiency, an internal resistance can be found that is assumed constant for all battery loading. Given the round trip efficiency, the rated power into and out of the battery is found by equations 3.1 for charging and 3.2 for discharging.

Charging: $$P_{BR} = P_R\sqrt{\eta_{RT}} \quad (3.1)$$

Discharging: $$P_{BR} = \frac{P_R}{\sqrt{\eta_{RT}}} \quad (3.2)$$

Where:

- P_{BR} is the actual rated power out of the battery
- P_R is the rated power of the inverter into the inverter on the DC side
- η_{RT} is the round trip efficiency of the battery at rated power

Community Energy Storage Controller:

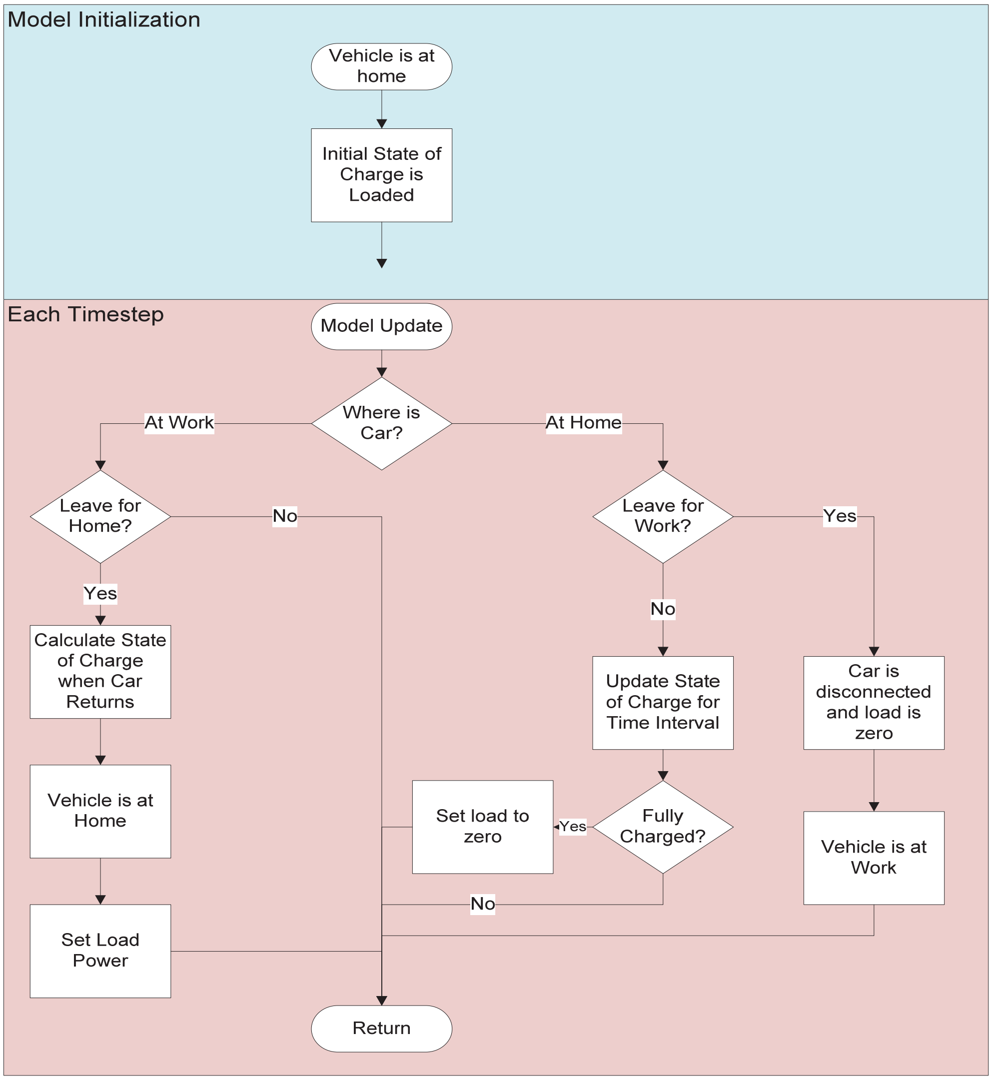
The Community Energy Storage (CES) controller is used to control/coordinate CES, which consists of multiple independent batteries and associated inverters. The CES controller can coordinate energy storage units to achieve one of three functions including (1) Var support, (2) Islanding and (3) Peak shaving (scheduled or load-following).

The controller looks at power measurements for each phase on a given sense node and then determines whether the measurements are within a specified bound. Depending on these criteria, the controller instructs all of the CES and NaS units (battery and inverter objects) under its control to output a certain power level up to, but not exceeding, the rated inverter power for each unit.

2.2.3 Electric Vehicle Module Development

An existing Electric Vehicle (EV) module is available with GLD. The standard version only supports scheduling trips from home to work and back and it is not able to distinguish between weekdays and weekends. The goal of this effort was to provide more scheduling flexibility allowing for more realistic EV use patterns. Battelle initially anticipated that changes were needed to the EV module source code, however they later proposed that GLD's scheduling functions could be leveraged in innovative ways to achieve the desired outcomes. Ultimately no change to the source code was needed. Figure 3 below is a diagram of how the EV module operates.

Figure 3: Electric Vehicle Module Operation



2.2.4 Valuation Pipeline Framework

The Valuation Pipeline tool was built to be a flexible cost-benefit framework to capture the value streams (benefits and burdens) of DERs from the perspective of the Customer, Utility and Society. From the customer perspective, the value streams include (1) cost of technology and (2) the savings from change in consumption, rebates and incentives. GLD directly calculates the change in customer energy consumption while the user inputs values for the cost of energy, technology and rebates into a configuration file. The total customer value stream is calculated from the below formula:

Customer value streams = Cost of Technology + Energy Savings

From the Utility perspective, value streams can be attributed to Generation, Transmission and Distribution. Since GLD is limited to distribution level simulations, the Generation and Transmission value streams are not directly computed by GLD but can be provided by the user via a configuration file. The Distribution value streams include (1) Deferred Distribution Upgrade

Project Costs, (2) Required Distribution Upgrade costs and (3) Net energy losses. The total distribution value stream is calculated as:

Utility Distribution Value Streams = Costs of deferred projects + required distribution upgrades + Net energy loss

To perform the cost benefit analysis on the distribution circuit certain measurements are made to help quantify the cost of the distribution system and to flag equipment that need to be upgraded. These measurements include:

1. Feeder head (Power Factor, Reverse Power Flow and Load imbalance
2. Capacitor switching operations
3. Bill dumps which includes detailed customer usage
4. Violation records to record (Line voltages, transformer loading, line thermal limits, load imbalances and reverse power flow

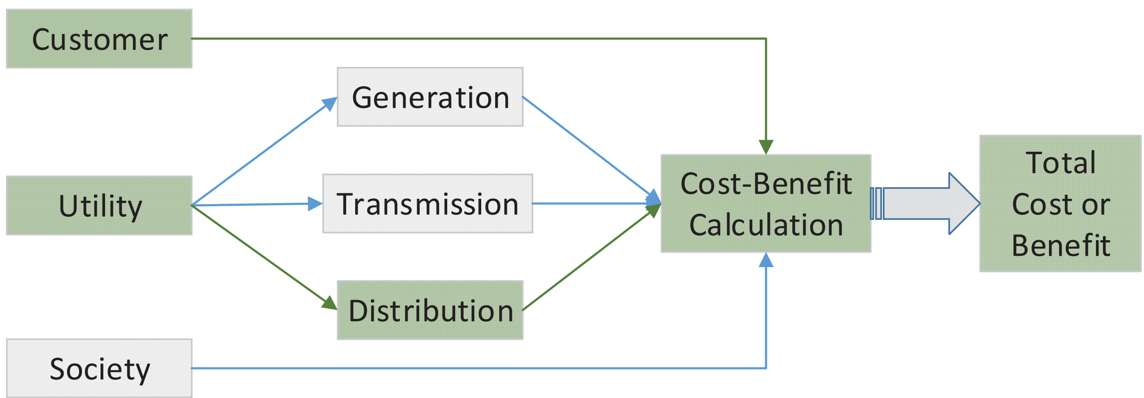
Both the trigger flags and the costs of the infrastructure to mitigate these issues are provided by the user. An example of the distribution value stream configuration file is given in Figure 5 below:

Figure 4: Example of Distribution Upgrade Triggers & Costs

Category	Criteria	Infrastructure	Trigger/Flag	Costs
Voltage	Overvoltage	House (meter)	≥ 1.05 Vpu	7.15 $/ft
	Voltage Deviation	Lines	≥ 3% at primary nodes	OH 55.88 $/ft UG 76.70 $/ft
		Secondaries	≥ 5% at secondary nodes	See above
		Regulators	≥ half bandwidth at regulators	$112551/each
	Unbalance	Sub, Lines	≥ 3%	See above for line costs $250000/rephasing
Loading	Thermal	Lines, Secondaries	≥ 100% normal rating	See above
		Transformers	≥ 150% normal rating	See chart
	Unbalance	Sub, Lines	≥10%	See above for line costs/rephasing
	Reverse Flow	Sub	< 10% of Peak	$100000/relay upgrade

The value streams from the society perspective can be defined by the user. This can include costs associated with reductions of carbon emissions or any other benefit that can be attributed to society. Figure 5 below shows the three main value streams. In the current framework, the streams colored in green are directly calculated via GLD simulations. The other value streams must be manually entered by the user.

Figure 5: Value Stream Calculation Process Flow



Valuation Framework Development:

The development of the Valuation framework required modifications to the existing GridCommand Distribution software. GridCommand Distribution is a front end addition to GridLAB-D providing a user interface to streamline and simplify the model building process easier. For the valuation framework, new functionalities were implemented in GridCommand Distribution which allowed recorders and collectors to be automatically placed at strategic locations throughout the distribution circuit. A configuration file to enter cost information and criteria for flagging upgrades is also provided via GridCommand Distribution.

2.3 Project Results

Battelle developed new pieces of source code and compiled this with the rest of the core GridLAB-D source code to make one executable. The following is a list of the modeling features and additional tasks that were provided by Battelle under this project.

- New Commercial module including Validation works
- New Valuation pipeline tool
- Enhanced Electric Vehicle module
- Enhanced Energy Storage module
- Documentation describing module development logic and functions
- Support services to develop 30 distribution models
- Training provided to SCE employees

There were some functions that were not implemented. The Contractor required more time than originally anticipated to develop some of the module and since the contract was "time based", these delays put a strain on the project budget and some of the planned modules could not be developed. SCE ultimately decided to cut the contract short after one of the main software developers working on the project resigned from Battelle.

2.3.1 Technical Results, Findings, and Recommendations

Battelle validated the Commercial module and the results how that the Commercial load model is able to predict the customer's monthly usage to within approximately 20% of the actual monthly usage. SCE validated the demand response features of the Commercial module and found that the commercial demand response features performs poorly and should not be used for planning purposes in its current state. The Valuation Framework, Energy Storage and Electric Vehicle modules were not validated.

Improvements need to be made to the Commercial module to properly simulate commercial AC/Heater demand response events. The Commercial load model predicted monthly usage to roughly 20% of the actual value. It is likely however that the predictions at smaller time scales, than 1 month, will be less accurate. The Valuation Pipeline framework seems to be promising tool. SCE will conduct validation tests on the valuation pipeline tool to determine if it can be leveraged for planning.

2.3.2 Technical Lessons Learned

The development of certain modeling features using GLD proved to be more challenging that initially anticipated. This was especially true with the development of the Commercial demand response functions. The difficulty was not so much with regards to the programming aspect of it, but with regards to the mathematical work necessary to properly fit the model and to decompose the customer AMI data into theoretical load components.

Potential factors that may have contributed to the poor performance of the HVAC model include (1) the number of distinct commercial customer groups defined, (2) the sample size of the historical demand customer usage information provided and (3) the validity of coefficients used to perform the multiple regression analysis to predict usage and the cooling and heating load components. For example the customer demand sample size was 6,700 customers, which represents approximately 1% of the total commercial customer base. This sample size may not have been large enough to extract meaningful data.

2.3.3 Value Proposition

SCE has identified the need for new advanced distribution circuit modeling tools as one of the foundational technology solutions necessary to help realize a modernize grid. The tools developed under this project help to satisfy this need and will provide great value as it guides SCE's future investments towards a modernized grid. More immediately, these capabilities can help to satisfy regulatory requirements for utilities to identify locational net benefit of DERs, incorporate DERs into grid planning activities and support demonstration projects such as the Integrated Grid Project which satisfies the requirement to perform Distribution Resource Plan Demo D.

The 30 distribution models developed were used in a core research project to study the impacts of high PV penetration and to determine the optimal set of mitigation strategies to enable 100% PV penetration on the circuits studied. Additionally the results from this simulation were used to compare SCE's initial DRP Integrated Capacity Analysis (ICA), which determined the hosting capacity on the same set of 30 distribution circuit, but using a different set of criteria and a different power simulation tool, CYME.

The modeling functionalities developed under this project support the primary and some of the secondary EPIC guiding principles. The valuation pipeline tool is used to determine the locational value of DERs. This information can help the utility align incentives with DER value thus promoting increased DER adoption in areas where there is most benefit to the grid. Likewise the Commercial, Electric Vehicle, and Energy Storage modules will all help to enhance the accuracy of the simulations. This will help to optimize DER resource deployments and thus reduce cost and reduce emissions.

2.3.4 Technology/Knowledge Transfer Plan

SCE will work with Battelle to ensure that the specific changes made to GLD, the work done collaboratively on this project and the reasoning behind the major decisions made during the project are made publically available, drawing conclusions about the realized and expected societal benefit from this work.

2.4 EPIC Metrics

List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation)	
2. Job creation	
a. Hours worked in California and money spent in California for each project	See 5.1
3. Economic benefits	
a. Maintain / Reduce operations and maintenance costs	See 5.2
c. Reduction in electrical losses in the transmission and distribution system	See 5.3
4. Environmental benefits	
a. GHG emissions reductions (MMTCO2e)	See 5.4
7. Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy	
b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360);	See 5.5
c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360);	See 5.6

2.4.1 Hours worked in California:

Labor costs were supported for the engineers working at Southern California Edison. This included time spent on the project management, validation works, and works done in developing 30 distribution circuit models.

2.4.2 Reduce O&M costs:

The valuation pipeline framework will help determine the burdens that Distributed Energy Resources will have on the system. This tool automatically flags equipment that need to be upgraded as a result of new DERS and thus giving the planner greater visibility into potentially issues before they occur. This can help prevent equipment from prematurely failing. The Energy Storage controller will help inform actual energy storage coordination schemes to regulate extreme circuit loading conditions and also regulate VAR flow which can help reduce capacitor operations.

2.4.3 Reduction in electrical losses:

Each of the new features developed will play a role in informing the planning and design of the future distribution system. These planning activities routinely revolve around making the distribution system more efficient. The Energy storage module can be used to help smooth out peaks in circuit load, the Electric Vehicle module can help inform the planner about potential overloading issues due to EV adoption. The valuation pipeline tool likewise can be used to help incentive customers to utilize DERs in a way that can reduce losses on the transmission and distribution lines.

2.4.4 Reduction in GHG emissions:

The tool developed will be used to help design the distribution system so that it can safely and reliably support increasing amounts of DERs. The more DERs are connected to the grid the less GHG emissions can be expected.

2.4.5 Increased use of digital information and control technology:

The Energy Storage controller can be used to coordinate the operation of multiple energy storage devices to achieve various objective functions such as VAR support, peak shaving and load following. These capabilities can help to provide insight on the best mix of objective functions to inform future control schemes and technology.

2.4.6 Dynamic optimization of grid operations:

The 30 distribution models were used to perform numerous high PV penetration scenarios. These included scenarios to determine the optimal mix of traditional upgrades and support services from DERs to enable up to 100% PV penetration levels. SCE developed the 30 distribution models, in part by leveraging the Commercial module and using support services and training provided by Battelle.

3 Sub-project 2: Hosting Capacity Analysis

3.1 Project Summary

This project demonstrated the methodology to determine the level of DERs that could be interconnected to the distribution system without adversely affecting the critical distribution system components and developed the process of sharing the hosting capacity results to the public in order to facilitate DER adoption economically.

3.1.1 Project Objective

The primary goal of this project was to demonstrate a dynamic hosting capacity methodology, within selected study areas, that could be used to determine the capacity of distribution system to integrate DERs down to a line section or node level.

3.1.2 Problem Statement

SCE, in its recently released whitepaper "The Emerging Clean Energy Economy," outlined a vision to accelerate the transition to a clean, reliable energy future that includes a high penetration of DERs, by facilitating customer choice of new technologies, creating opportunities for DERs to provides grid services, and modernizing the grid to ease integration and optimization of DERs.

The expected high levels of DERs on SCE's distribution system will have significant impacts on all critical distribution system functions. These include: maintaining distribution system electrical components within thermal limits, maintaining power quality within applicable industry standards, and maintaining the necessary level of protection to provide safe and reliable electrical service to customers. The determination of the maximum amount of DERs that can be connected without adversely impacting SCE's distribution system functions (referred to as the hosting capacity) involves rigorous engineering analysis and review.

3.1.3 Scope

The project was planned to demonstrate a fully dynamic analysis which would determine the DER hosting capacity at line sections and/or nodes within the distribution system.

The demonstration was to be performed in two distinct areas that represent the wide variety of distribution systems within SCE's diverse service territory, such as a typical urban service area and a typical rural service area. Through this analysis, the project was to investigate and demonstrate the impact of the characteristics of local distribution systems the level of DERs that can be interconnected to the distribution grid without adversely affecting the critical distribution system components.

The demonstration would examine 576 hours over a 12-month period, which composed of one day per month of typical high-load conditions and one day per month of typical light-load conditions.

The project was to examine the hosting capacities under two power flow scenarios: a) power does not flow towards the transmission system beyond the distribution substation bus; b) the technical maximum amount of interconnected DERs that the system is capable of accommodating irrespective of power flow direction.

The demonstration was planned to examine the hosting capacity based on limiting categories of thermal rating, power quality and voltage criteria including steady state voltage and voltage fluctuation, protection coordination requirements, safety and reliability, as well as substation limitations.

Two different methodologies of calculating the DER hosting capacities would be demonstrated. The first methodology, referred to as the Streamlined Method, was to perform one power flow simulation for each scenario and then extract quantities from the power flow simulation and insert them into the streamlined equations to determine the hosting capacities for each of the limiting categories. The second methodology, referred to as the Iterative Method, was to utilize iterative power flow simulations to determine the hosting capacities for each of the limiting categories.

The hosting capacity results would be published on SCE's Distributed Energy Resource Interconnection Map (DERiM) to share with the public.

All the above scopes were completed in this project.

3.1.4 Schedule

The project was officially commenced in May 2016, with necessary preparations carried out earlier, and was scheduled to complete by the end of 2016.

Table 6: Project Schedule

Project Schedule				
#	Taks	Duration (Days)	Start Date	End Date
1	Area Selection	34	5/2/2016	6/16/2016
2	Circuit Model Development	31	6/17/2016	7/29/2016
3	Load Shape Development	31	6/17/2016	7/29/2016
4	DER Portfolio Development	54	6/17/2016	8/31/2016
5	Script Development	31	6/17/2016	7/29/2016
6	Hosting Capacity Simulation	55	8/1/2016	10/14/2016
7	Comparative Assessment	54	9/1/2016	11/15/2016
8	Map Development	121	7/15/2016	12/30/2016
9	Project Report	50	10/17/2016	12/31/2016

3.1.5 Milestones and Deliverables

The project deliverables were composed of 1) an implementation plan outlining the detailed project plan including area selection and scenario development; 2) an intermediate status report presenting the project status and the final methodology; 3) a final project report summarizing the project activities and results; and 4) an online map presenting the results to public. All the milestones and deliverables have been completed on time.

Table 7: Project Milestones and Deliverables

Milestone/Deliverable	Status	Date
Implementation Plan	Completed	6/16/2016
Intermediate Status Report	Completed	9/30/2016
Final Project Report	Completed	12/23/2016
Online Map Display	Completed	12/23/2016

3.2 Test Set-Up/Procedure

3.2.1 Area Selection

SCE's service territory covers a wide area varying in electrical and physical characteristics. Two areas were selected to represent a broad range of physical and electrical conditions within SCE's distribution system as presented in Table 8. The selected distribution planning areas (DPAs) are an urban and a rural DPA, as their geographic locations shown in Figure 4.

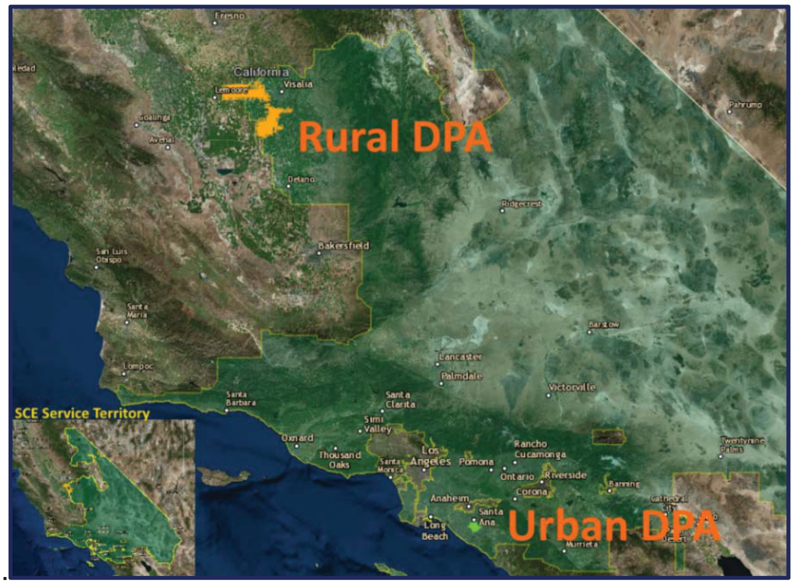


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Figure 4: Geographic Locations of Selected Areas

Table 8: Overview of Area Characteristics

	Urban DPA	Rural DPA
Area	Orange County	Central Valley
Service Area Size	18 mi^2	120 mi^2
No. Feeders	38	44
No. Customers	25,100	49,700
2016 Projected Load	217 MVA	314 MVA
No. Service transformers	2,375	9,617
Load types	Mixture of residential, commercial, and light Industrial loads	Mixture of residential and commercial, with significant agricultural loads
Substations	Johanna 66/12, Camden 66/12, Fairview 66/12, Edinger 12/4.16	Goshen 66/12, Hanford 66/12, Mascot 66/12, Octol 66/12, Tulare 66/12
Special Notes:	Within PRP region	Load growth driven by drought conditions

3.2.2 Methodology

Figure 5 illustrates the general process of the hosting capacity calculation. After the system model data and load data are extracted from various databases, the distribution feeder models are developed in the power flow analysis tool CYMDIST. The applicable power system criteria are examined based on 1) pre-defined equations in the Streamlined Method and 2) iterative power flow simulations in the Iterative Method. Each of these two methods identify the maximum DER integration capacity at each node. The DER hosting capacity for each criterion is calculated independently and the most limiting value is used to establish the final hosting capacity limit.

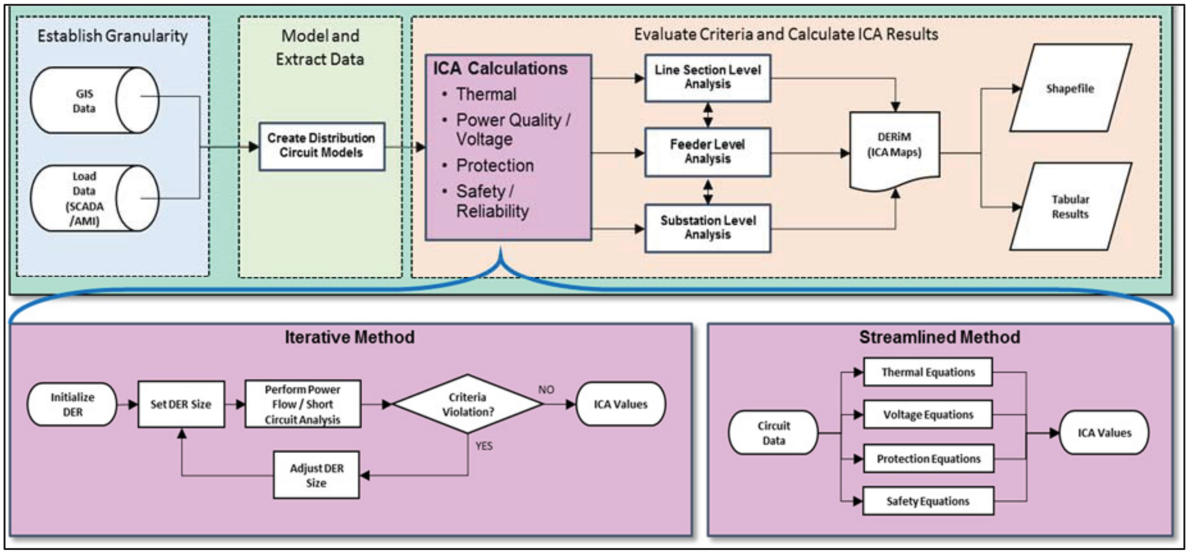

Figure 5: Process Diagram

The hosting capacity methodology composed of four general steps:

- Establish distribution system level of granularity;
- Model and extract power system data;
- Evaluate power system criterion to determine DER capacity;
- Calculate ICA results and display on online map.

The Streamlined Method applied a set of streamlined algorithms for each power system limitation category/sub-category to evaluate the DER capacity limit at each node of the distribution feeders. Figure 6 illustrates how each power system limitation criterion is evaluated at each node though power flow or short circuit duty (SCD) analyses and how the final hosting capacity values are established at each node based on the most limiting individual values. For the scenario that is to evaluate the maximum integration of DER irrespective of direction of power flow, the safety/reliability criterion (i.e., operational flexibility) will be excluded so that the maximum DER can be studied irrespective of power flow direction

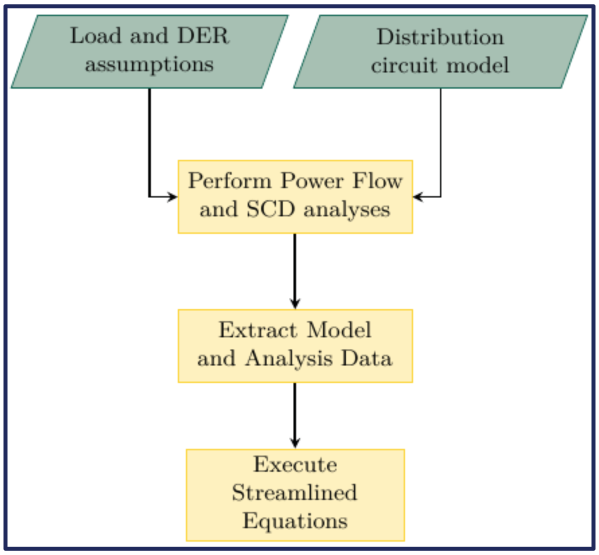

Figure 6: Criterion Evaluation Process

The Iterative Method is the direct modeling of new resources and performing iterative simulations for determining the hosting capacity at each node. Each analysis uses power flow calculation engines to compute the phase currents and voltages at every node on the network given the load and generation levels in the model. Figure 7 illustrates how each power system limitation criterion is evaluated at each node though power flow or short circuit analyses and how the final hosting capacity values are established at each node based on the most limiting individual values.

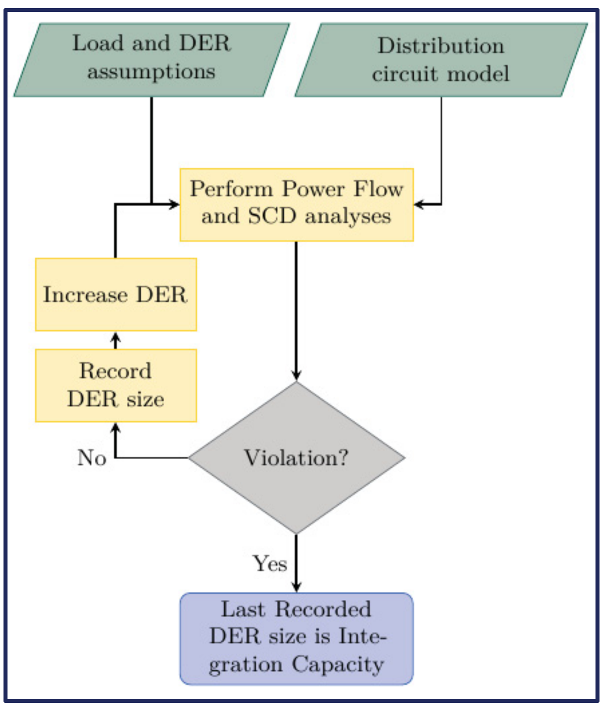

Figure 7: Simplified High-Level View of Iterative Methodology

3.2.3 Limitation Category

This section shows the equations and flags used to evaluate different limitations in the Streamlined Method and the Iterative Method, respectively.

3.2.3.1 *Thermal Criteria*

Streamlined	$\text{kW Load Limit [t]} = \left(\text{Thermal Capability} - \left(\text{Load[t]} - \text{Generation [t]}\right)\right)$ $\text{kW Generation Limit [t]} = \left(\text{Thermal Capability} + \left(\text{Load[t]} - \text{Generation [t]}\right)\right)$
Iterative	Power flow determines maximum DER without exceeding device thermal rating

3.2.3.2 *Steady State Voltage Criteria*

Streamlined	$\text{kW Limit [t]} = \frac{\left(\text{Voltage Headroom [t] (per unit)} * V_{LL}{}^{2}\right)}{\left(R * PF_{DER} + X * \sin\left(\cos^{-1}(PF_{DER})\right)\right)} * PF_{DER}$ $\text{Voltage Headroom [t]} = \frac{\lvert\text{Rule 2 Limit} - \text{Node Voltage[t]}\rvert}{\text{Base Voltage}}$
Iterative	Power flow tool flags a steady state over-voltage condition when simulated voltage at any node exceeds 126V and flags an under-voltage condition when simulated voltage drops below 114V at any node.

3.2.3.3 *Voltage Fluctuation Criteria*

Streamlined	$\text{kW Limit} = \frac{\left(\text{Deviation Threshold (per unit)} * V_{LLnom}{}^{2}\right)}{\left(R * PF_{DER} + X * \sin\left(\cos^{-1}(PF_{DER})\right)\right)} * PF_{DER}$
Iterative	a. Record voltage at node b. Simulate generation at node c. Vary generation levels until deviation threshold is surpassed d. Generation level closest to but under the allowed deviation value is the limit e. Compare node voltages with DER on and off f. Highest value recorded before deviation threshold is surpassed

3.2.3.4 Protection Criteria

Streamlined	$$\text{kW Limit} = \frac{\text{Reduction Threshold Factor} * I_{\text{Fault Duty}} * kV_{LL} * \sqrt{3}}{\left(\frac{\text{Fault Current}_{DER}}{\text{Rated Current}_{DER}}\right)} * PF_{DER}$$
Iterative	Power flow tool flags when the DER connected at a node causes the relay to detect less than 2.3*relay's phase minimum trip value (SCE's typical practice of applying minimum trip settings)

3.2.3.5 Operational Flexibility Limits

Streamlined	$\text{kW Limit}\,[t] = \left(\text{Load}[t] - \text{Generation}\,[t]\right) \mid \text{where limit} > 0$
Iterative	Power flow tool calculates the downstream load at the SCADA or VR devices and equates that load value to be the DER value which can be installed without causing reverse power flow. .

3.2.4 Map Display

The results of the calculated hosting capacity have been published as additional layers within SCE's existing Distributed Energy Resource Interconnection Map (DERiM) at http://on.sce.com/derim. DERiM is an interactive web map developed on ESRI's ArcGIS online platform. It performs calculations by collecting data from a variety of sources, such as cGIS (line routes and substation locations), Generation Interconnection Tool (interconnection queue), and Master Distribution Interface (forecast and equipment capacity). Users click on map features to obtain a variety of results, including the hosting capacity results. A sample map is shown in Figure 8.

In addition, an ArcGIS Online Web Application has been launched to publish interactive load profiles for circuits, substations, and DPAs (http://on.sce.com/derimwebapp). Lastly, SCE published comprehensive downloadable result files, by circuit, to a new webpage referred to as the DRP Demo Results Library (http://on.sce.com/drpdemos). Among all the downloadable files, there is a translator tool which interested parties may use to convert the agnostic hosting capacity values to a technology specific value, as shown in Figure 9.

All of the information published to the map or downloadable files will be subject to Personal Identifiable Information (PII) or Critical Energy Infrastructure Information (CEII) compliance requirements.

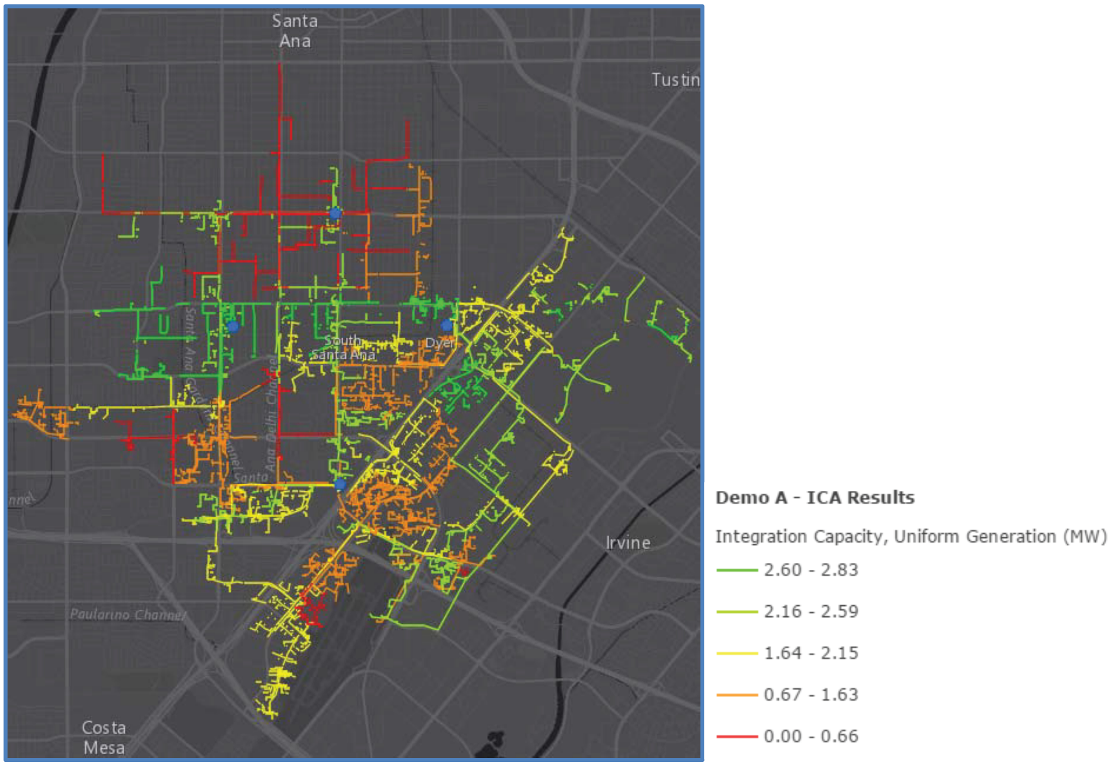

Figure 8: Hosting Capacity Sample Map

Southern California Edison ICA Translator V1.0

Instructions: Enter hourly Load Agnostic 576 Hourly ICA results in the left table to update the expected Load ICA limit based on the DER Profile category.

SCE does not guarantee the accuracy of the data. The data is intended for information only and the user is responsible for the accuracy and use of the data. SCE maintains ownership of this tool and can make changes at any time.

Technolgy specific ICA was limited to 4 times the average agnostic ICA. This was done to limit the technology ICA values to within technical reason. Not doin so would result in unrealistics technology specific ICA values at times when technology specific is very low or was zero for that hour. When techlogy specific output was zero for that hour, the techology ICA was set 4 times the average agnostics ICA.

USER SPECIFC ICA CALCULATION

Enter Agonostic Houly ICA Value			Universal Gen (Inverter)		PV		PV w/ Storage		PV w/Tracker		ENTER User Specified Gen Profile	User Specified Gen ICA Profile	
Hour	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Profile	Min	Max
1	3.136	3.136	3.1	3.1	11.5	11.5	11.5	11.5	11.5	11.5	0.033333333	11.5	11.5
2	3.134	3.134	3.1	3.1	11.5	11.5	11.5	11.5	11.5	11.5	0.033333333	11.5	11.5
3	3.134	3.134	3.1	3.1	11.5	11.5	11.5	11.5	11.5	11.5	0.033333333	11.5	11.5
4	3.121	3.121	3.1	3.1	11.5	11.5	11.5	11.5	11.5	11.5	0.033333333	11.5	11.5
5	3.111	3.111	3.1	3.1	11.5	11.5	11.5	11.5	11.5	11.5	0.033333333	11.5	11.5
6	3.111	3.111	3.1	3.1	11.5	11.5	11.5	11.5	11.5	11.5	0.033333333	11.5	11.5
7	3.111	3.111	3.1	3.1	11.5	11.5	11.5	11.5	11.5	11.5	0.033333333	11.5	11.5
8	3.111	3.111	3.1	3.1	11.5	11.5	11.5	11.5	9.3	9.3	0.335	9.3	9.3
9	3.107	3.107	3.1	3.1	9.3	9.3	11.5	11.5	4.6	4.6	0.673333333	4.6	4.6
10	3.107	3.107	3.1	3.1	6.3	6.3	11.5	11.5	4.0	4.0	0.773333333	4.0	4.0
11	3.107	3.107	3.1	3.1	5.2	5.2	11.1	11.1	3.8	3.8	0.820833333	3.8	3.8
12	3.107	3.107	3.1	3.1	4.6	4.6	8.2	8.2	3.8	3.8	0.820833333	3.8	3.8
13	3.101	3.101	3.1	3.1	4.6	4.6	7.2	7.2	3.8	3.8	0.820833333	3.8	3.8

Figure 9: Hosting Capacity Translator

3.3 Project Results

3.3.1 Technical Results, Findings, and Recommendations

SCE generated hosting capacity using a "technology-agnostic uniform generation and uniform load" approach so that the results are independent of the type of DER technology. SCE also developed a translator to translate the technology-agnostic uniform generation or load hosting capacity values into a desired, specific technology or portfolio of technologies.

Through this demonstration, SCE strived to find the proper balance of accuracy of results and computational time requirements, to produce meaningful hosting capacity values that would be useful for near-term use-cases while also allowing for continued refinements of the methodologies and calculations for long-term applications. SCE proposes that a Blended Method should be adopted for initial implementation of hosting capacity calculations across the SCE service territory. This method would use the Iterative Method on the typical 24-hour, light-load day in an annual period, which yields the necessary information required under the existing Rule 21 process, while developing a full 576 hourly (typical high load day and typical light load day for each month) calculation utilizing the Streamlined Method to provide information for planning purposes and to produce technology-specific hosting capacities. SCE believes this blended approach would establish a solid baseline for the development of a more complex, long-term hosting capacity analysis.

SCE believes that as the hosting capacity calculation methodologies continue to evolve, as tools become more effective, and as network models become more accurate through use of enhanced SCADA data, the efficiency of producing the hosting capacity values and the accuracy of the hosting capacity values will increase. Therefore, SCE recommends that for the initial phases, the proposed Blended Method should be adopted with the understanding that continuous improvements will occur based on technology improvements, tariff modifications, and improvements in network models.

Long-term, more complex hosting capacity applications would include the applicability of smart inverters and transmission-level evaluations. The most immediate use of the hosting capacity values would be in expediting the interconnection process through modifications of SCE's Rule 21 tariff filed with the California Public Utility Commission. Other likely use cases include the application of hosting capacity information by SCE in its annual planning processes to aid in forecast development.

3.3.2 Technical Lessons Learned

The calculated hosting capacity results showed significantly different patterns between the urban area and the rural area. Circuits in the rural arear tend to have lower hosting capacities. Therefore, it is necessary to study different feeder characteristics in order to obtain a complete understanding of the hosting capacity pattern.

Typically, in most rural feeders, the steady state voltage and the operational flexibility criteria are the most limiting factors for nodes towards the end of the feeders; on the other hand, in most urban feeders, the operation flexibility limitation would be the most limiting factor for nodes near the substation while the steady state voltage would commonly be the most limiting factor for nodes further away from the substation.

The Streamlined Method performs one power flow simulation per hour of analysis to extract initial circuit electrical parameters to input into external equations. This method yields results quickly, is highly efficient in terms of the computational time required to produce hosting capacity values. However, for areas with voltage regulation schemes, areas distant from the substation, or systems with low short-circuit duty values, this method may not detect violations of voltage or thermal limitations accurately. In contrast, the Iterative Method performs multiple power flow simulations with varying levels of DERs connected. This method can produce the most accurate results that could be applied more seamlessly in the interconnection process. However, thousands of simulations for each feeder are needed, which significantly increases computational time.

3.3.3 Value Proposition

Through this demonstration, essential information is provided to the public to enable strategic DER siting which could help not only expedite the interconnection process but also avoid unnecessary system upgrade in order to accommodate the DER interconnection. This will lower costs while promoting enhanced environmental sustainability.

In the long term, this information can be integrated in SCE's annual planning process so that the possible impacts and benefits of DERs can be considered during the distribution planning process in order to develop cost effective system upgrade plans to safely and reliably supply electricity to all the customers. It can put ratepayers' money in efficient use.

3.3.4 Technology/Knowledge Transfer Plan

SCE has provided detailed project reports explaining the methodologies and the equations. The reports and detailed study results were made publicly available through the online map display so that users can not only access the overall hosting capacity results but also download the detailed results for in-depth analysis. SCE also performed benchmark analysis on IEEE 123-node feeder which is publicly available so that third party users or other utilities can perform the same analysis on the test feeder to understand the process, examine the results, and even perform additional analysis.

3.4 Metrics

List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation)	
2. Job creation	
a. Hours worked in California and money spent in California for each project	See 5.1
3. Economic benefits	
a. Maintain / Reduce operations and maintenance costs	See 5.2
c. Reduction in electrical losses in the transmission and distribution system	See 5.3
4. Environmental benefits	
a. GHG emissions reductions (MMTCO2e)	See 5.4
7. Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy	
b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360);	See 5.5
c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360);	See 5.6

3.4.1 Hours worked in California:

Labor costs were supported for the engineers working at Southern California Edison. This included time spent on the project management, model and algorithm development, hosting capacity simulation and results analysis, and online map development.

3.4.2 Reduce O&M costs:

The methodologies developed, demonstrated, and recommended in this project will help DER developers to design the most economic project plans, and help SCE to expedite the interconnection process through modifications of SCE's Rule 21 tariff filed with the California Public Utility Commission. This project can also help integrate the hosting capacity information in SCE's annual planning processes to aid in forecast development.

3.4.3 Reduction in electrical losses:

Not Applicable

3.4.4 Reduction in GHG emissions:

The project will provide DER developers the available hosting capacity on the distribution system without system upgrade, this information can help developers design cost effective project and expedite the interconnection process therefore encourage and facilitate the integration of clean energies and to reduce the GHG emission.

3.4.5 Increased use of digital information and control technology:

Not Applicable

3.4.6 Dynamic optimization of grid operations:

Not Applicable.

4 Appendix

List of Acronyms

ARRA	American Reinvestment and Recovery Act
AT	Advanced Technology (the organization)
ATP	Advanced Technology Procedure, or Authority to Proceed
BOM	Bill of Materials
CCB	Change Control Board
CMO	Compliance Management Office
COTS	Commercial Off-The-Shelf
CPUC	California Public Utilities Commission
DBE	Disadvantaged Business Enterprise
DOE	Department of Energy
eDMRM	electronic Data Management/Records Management
EPIC	Electric Program Investment Charge
FY	Fiscal Year
GRC	General Case
IAW	In Accordance With
ICC	Integrated Change Management
IO#	Internal Order Number
IP	Intellectual Property
O&M	Operations and Maintenance
PDF	Portable Document Format (Acrobat file)
PfMP	Portfolio Management Plan
PM	Project Manager
PMBOK	Project Management Body of Knowledge
PMI	Project Management Institute
PMO	Portfolio Management Office
PMP	Project Management Plan
PMR	Portfolio Management Review
PO	Purchase Order
PPM	PMO Process Matrix
PPP	PMO Procurement Plan
PRR	PMO Risk Register
PSR	Project Status Review
SCE	Southern California Edison

SME	Subject Matter Expert
TFC	Termination for Convenience
TL	Technical Lead
Ts&Cs	Terms and Conditions

Glossary

Term to define	Definition here

Also see glossary's available for the electric utility industry available on the internet like this one: http://www.nwppa.org/advertise_sponsor/Facts_Figures_Glossary_of_Terms.aspx)

Appendix B

Advanced Technology Dynamic Line Rating

Final Project Report

Advanced Technology
Dynamic Line Rating
Final Project Report

Developed by

SCE Transmission & Distribution, Advanced Technology
Organization

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Southern California Edison – Advanced Technology
14799 Chestnut St.
Westminster, Ca 92683

Disclaimer

Acknowledgments

Prepared for: Southern California Edison, Advanced Technology, Public Utilities Commission of the State of California

Prepared by: Backer Abu-Jaradeh

Principle Investigators (s) Backer Abu-Jaradeh, Farrokh Habibi-Ashrafi

Change Log

Version	Date	Description of Change	Project Report No.
0.01			

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None

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Preface

1 Executive Summary

Transmission Line ratings are currently preset based on many environmental and engineering factors such as cable material, weather conditions... etc. Usually, Line ratings are set to be conservative to prevent exceeding minimum clearance above ground and line overheating. Dynamic Line Rating is an approach that uses sensors to measure current operating conditions and develop a real time rating that reflects the current conditions of the line. This may allow better utilization of the line and increase in line transfer capacity during normal operating conditions.

The system will change the line ratings based on near real-time measurements which reflect the current operating condition of the line rather than having a fixed conservative rating for all weather conditions throughout the year.

The system will cut down O&M costs as it will delay the need of building new transmission line by better utilizing existing transmission system. The system will use the near real-time measurements to evaluate how much added ampacity can be pushed through the transmission line during cooler hours.

2 Project Summary

The objective of this project is to install advanced sensors on high-voltage transmission lines to be able to better utilize the lines by pushing more power through them when needed based on current conditions (e.g. temperature, line sag, wind… etc.). Line ratings will be dynamically changed to provide the operators with near-real time ratings based on line conditions as opposed to the fixed pre-calculated ratings.

2.1 Project Objective

Transmission Line Monitor (TLM) devices will monitor line temperature and direct line clearance of the ground in real-time to evaluate the capacity of the transmission line dynamically instead of relying on conservative static ratings. Dynamic ratings will help better utilizing the system and accurately measure transmission line capacity and loading capability in real time under current operating conditions.

2.2 Problem Statement

The existing SCE operating practice is to use fixed line ratings that are pre-calculated based on assumed-fixed conditions throughout the year. The primary DLR instrumentation deployed with CAT-1 technology is based on a tension monitoring system developed by The Valley Group, a component of Nexans. The CAT-1 system incorporates a load cell into the dead-end insulator assembly at the end of each stringing section of conductor. The load-cell measures the tension of the conductor and sends a signal to a local processor at the structure. The main units are configured to communicate by DNP 3.0 protocol via an RS-232 interface. The tension data, ambient temperature and data on the solar radiation affecting the conductor are sent to a nearby substation via radio transmission. At the substation the data is streamed via RTU and SCADA system to the Energy Management System (EMS) using any supported SCADA protocol.

Through the Nexans algorithm, the data is transformed into a conductor temperature representative of the line section the load cell is monitoring. From that information, the effective ambient conditions are measured and calculated. Then the algorithm calculates what the maximum current capacity would be before the conductor would reach the minimum clearance (maximum sag condition). This revised allowable current is the *Dynamic Line Rating* for the line section. By monitoring multiple sections of a transmission line to account for different line orientation, stringing conditions or terrain, the minimum dynamic rating can be identified and used for optimum operation of the transmission line.

2.3 Scope

The CAT-1 Transmission Line Monitoring System monitors the mechanical tension of the transmission conductor. The sag of any transmission span is inversely proportional to the horizontal component of the tension and is directly related to the temperature of the conductor; therefore CAT-1 data can be used to accurately calculate conductor temperature and report the actual current carrying capacity of the transmission line.

The CAT 1 remote unit is mounted on the transmission structure. The load cells are mounted between the "un-energized" side of the dead-end insulators and the structure. The components of the system located on the transmission structures are:

- One CAT 1 Main unit – in an aluminum enclosure, which houses the circuit board and communications device
- One CAT-PAC unit – in an aluminum enclosure, which houses the batteries and solar regulator charger
- Two 20W solar panels – mounted to the CAT-PAC enclosure
- Two stainless steel load cells - with integral hardware and shielded cables
- One ambient temperature sensor - in an aspirated shield
- Two Net Radiation Sensors – to measure the effect of solar radiation on the conductor
- One directional (Yagi) antenna and antenna cable

The radio signals used in this system require the antennae to have "line-of-sight" installation arrangement. To achieve this, a CAT 1 Repeater Unit may also be required. This unit consists of:

- Two Radios – one for communicating with the CAT 1 field equipment, the other for communicating with the Substation equipment
- Two Batteries – to power the radio equipment
- Three solar panels – to provide a charge supply for the batteries
- Two directional antennae – one for each of the radios

2.4 Schedule

A high level schedule overview is presented in the following table:

Task Name	
Authority to proceed	**Jan 2, 2015**
Publish Standard pilot approval process	**Aug 28, 2015**
Substation Construction	**Aug 28, 2015 – Sep 15, 2015**
Telecom Construction	**Sep 18, 2015 – Oct 16, 2015**
System Configuration & Testing	**Oct 19, 2015 – Dec 18, 2015**

Pilot operation	**Dec 19, 2015 – Dec 19, 2016**
Project Close out	**Dec 19, 2016 – Feb 16, 2017**
End project	

Table 1 Project Schedule

2.5 Milestones and Deliverables

Table 2 shows a list of milestones and deliverables. Due to early close-out of project, a status of "cancelled" is shown in status column.

Milestone/Deliverable	Status
PO Issued	Completed
Towers Selected and technical specs drafted	Completed
Computer based Line-of-sight analysis conducted	Completed
Equipment delivered	Completed
Pre-engineering Job walk conducted	Completed
Transmission Standards and training material drafted and approved	Completed
Engineering drawings issued	Completed
On-site Line-of-sight analysis	Cancelled
Transmission outage and construction	Cancelled
Substation construction	Cancelled
Pilot Operation	Cancelled
Final Report Out to Stakeholders	Cancelled

Table 2 Milestones and Deliverables

3 Test Set-Up/Procedure

The following test procedures were developed as part of the project to better assist in construction and implementation phases of the pilot.

1.0 Pre-Installation Checklist

Step 1. Identify dead-end hardware that may need to be changed or removes because of the extra slack that will be caused by the load cells additional length. Make sure that to have proper hardware to interface with the integral eye hardware of the load cells. It is a good practice to assemble all the pieces of hardware before going to the field. Re-check that load cells are properly rated for the maximum tension of your line.

Step 2. Check battery voltages to make sure that the CAT-1 is fully charged (over 12V reading at battery terminals). If necessary, the battery can be charged through the terminals on the control panel by using a standard battery charger. The charging current should not exceed 2A or the main fuse will open. It is a good idea to charge the batteries overnight before installation.

Step 3. Verify the line direction from line maps. The CAT-1 enclosure(s) and NRS mounting bracket should be located on the South (or North in the Southern hemisphere) face of the structure in order to maximize input to the solar panels and to reduce the possibility of shadowing of the NRS(s). For RTR systems, the azimuth for correct positioning of the radio antenna to direct it towards the CATMaster receiving site should be determined.

Step 4. Take a small electronic toolkit and a multi-meter with you, in addition to the equipment required by the linemen. Check that you have a spare fuse for CAT-1 in the main unit (component "F2"). A laptop computer and an RS 232 interface cable will allow Local mode use in the field.

Step 5. Edit the configuration table of the CAT-1 unit if necessary. Mark down, log, or print current log as well as changes made. See "Edit configuration (;E)".

Step 6. Take the right CAT-1 with the right accessories. All equipment shipped with a CAT-1 system is labeled with the intended installation location identified. The system is preconfigured with settings and offsets specific to the various components provided. It is therefore very important that the equipment for a given site is kept together and installed as indicated.

Step 7. Let us know about your planned installation dates well ahead of time. A minimum of two weeks of advance notice is suggested. We can discuss the installation with you, and ensure that technical support will be available to assist in the field as required for validation of your system warranty.

2.0 Field Installation of Hardware

2.1 Install the load cells. Depending on your company's practices, load cell installation may or may not be possible as hot line work. Insulators and extraneous hardware can be removed to lessen any slack created by the load cells. It is important to mount the load cells in a manner that does not cause torque on the load cell. Any torque exerted on the load cell may have a significant effect on the output of the cells. For connection to the eye hardware of the load cells, Y-clevis hardware is suggested. See diagram in Appendix A7 for typical load cell dimensions.

Make sure the load cell connectors do not come in contact with moisture! This will cause the load cell readings to go to full scale.

Electrically bypass and ground the load cell (for flashover current protection) with a copper braid of at least 200 kcmil. Snake the load cell cable down to where the CAT-1 main unit will be located. Temporarily attach the cable, if necessary. If installing on a wood structure, ground the load cell hardware to the structure ground.

The load cell cabling should be routed down the structure using a reliable method of affixing the cables to the structure to prevent them from blowing in the wind and abrading against structure components. Common methods include cable clamps, routing through PVC pipe, etc. Where the cable is routed along the transmission arm, it is crucial to ensure that it is not possible for the means of support to fail enabling the cable to fall into the energized phase. Wrapping the cabling around the transmission arm is one method of ensuring this.

2.2 Attach the CAT-1 main unit and CAT-PAC on the structure or to the pole using standard hardware, such as uni-strut or pole bands. The CAT-1 unit must be grounded. This is especially important to remember when installing on wood structures. Make sure that you mount the main unit on the south side of the structure, so that the solar panel(s) will point towards true south.

2.3 Mount the NRS mounting bracket to the structure on the south face of the structure at an elevation which approximates the position of mid-span sag of the conductor under normal everyday operating conditions. The NRS(s) are aligned in the same direction as the line section(s) being monitored. The NRS with the blue port connector is associated with the black port 1 load cell. The NRS with the green port connector is associated with the red port 2 load cell.

Make sure that the NRS(S) will not be shielded from the sun by the structure for any part of the day.

2.4 Attach the antenna to an antenna mounting bracket and route the antenna cable to the CAT-1 unit. Communications should be tested by taking a field strength reading using software provided with the system.

2.5 Mount the solar panels to the mounting tabs provided on the bottom of the CAT-PAC unit (as indicated in the Mounting the Solar panels and the NRS(s) section). The ambient sensor in its aspirated shield is to be installed on the top right mounting ear on the CAT-1 main unit enclosure at a 45 degree angle away from the box.

2.6 Connect the load cell cables to the bottom of the CAT-1 unit, making sure that the correct load cell is connected to the correct port (Port 1 connectors have black tape, while Port 2 has red). Do not expose the connectors to any moisture, as this may give you full scale readings. They should be hand tightened (i.e. never use a wrench).

2.7 Open the sensor's junction box. Route the cables through the strain relief openings at the bottom of the junction box. Attach black, white, green, brown, red wires to 1-5 (extension cable to CAT-1), and black, white, green, red to 6-9 (to wind sensor). Close the junction box. In most cases, these connections should already have been made at the factory. Attach the junction box to a convenient location on the structure between the anemometer and the CAT-1 unit. Be sure to ground the junction box to the structure ground. Tie or tape the wind sensor cable down. Plug the cable into the appropriate port marked "AUX" at the bottom of the main unit.

2.8 RTR systems can be tested by placing the main unit in “LOCAL” mode. The [;C] command can be used to determine if reasonable tension and temperature measurements are being taken. Next, place the system in “AUTO” mode and cycle the power. After the system has powered on it will sample its ports and wait the programmed report delay interval. The system will then attempt to communicate with the CATMaster via DNP 3.0 protocol. This will be evidenced by seeing garbled ASCII characters appear in the terminal program. This is the binary data traffic being sent over the radio. If the ASCII characters appearing on the screen repeat multiple times, this is an indication that the CAT-1 is not establishing communications with the CATMaster. Please contact TVG for further troubleshooting steps.

2.9 Set the CAT-1 to "AUTO". Cycle the power OFF, power ON. Close the cover and lock the latches. Additionally, it is recommended that a padlock be installed on the provided hasp.

3.0 Mounting the Solar Panels and the NRS(s)

3.1 With the solar panel detached from the CAT, verify proper operation of the solar panel with a multi-meter. The open circuit voltage read between pins A and B of the solar panel connector should be 16.0-17.5V in direct sunlight.

3.2 With the solar panel plugged into the CAT-1, turn the solar panel face down on the ground. Plug your multi-meter leads into the battery terminals. When the solar panel is turned face up into direct sunlight, you should see a change of about +0.2 to +1.0V.

3.3 The NRS(s) are installed on the provided NRS mounting bracket. Make sure that the five (5) thermally insulating washers are placed between the NRS and the mounting bracket (and another five (5) between the NRS's if two are used). Tighten the plastic bolt with care, as it is somewhat fragile.

3.4 Attach the 5-pin connector from the NRS with the blue tape to the corresponding connector on the bottom of the main unit, marked "NRS1". If a second NRS is to be used, it will have green tape and is attached to the corresponding port on the CAT-1 marked "NRS2". Note that the connector can only go in one orientation. Tighten the connectors hand tight only.

3.5 The solar panel you have received should be set to the correct latitude for your installation location. Adjust the bracket to match the marked indication and tighten the bolts.

3.6 Attach the solar panels to the mounting lugs at the bottom of the front face of the CAT-PAC enclosure. Do not fully tighten the bolt yet, allowing side to side movement still.

3.7 Attach the solar panel connectors from the solar panels to the corresponding connectors on the bottom of the CAT-PAC unit. Note that the connector can only go in one orientation. Tighten the connector hand tight only.

3.8 Attach the ambient temperature sensor in its aspirated shield to the upper right mounting tab on the CAT-1 enclosure. Position the sensor shield at a 45 degree angle away from the enclosure. The ambient sensor connector is attached to the corresponding connector marked "AMB" on the bottom right of the main unit. Note that the connector can only go in one orientation. Tighten the connector hand tight only.

3.9 Align the solar panels toward due south. Tighten the bolts attaching the solar panels to the CAT-1 enclosure.

4.0 Calibrating the System

In order to determine the tension-temperature behavior of the line a calibration of each load cell must be performed. This is done by taking the line out of service or by reducing the current to a level low enough to ensure that heat rise on the conductor is negligible. A line loading of 5-10% of the static rating is typically low enough to consider being equivalent to an outage.

For the most accurate calibration, it is best to collect outage data at night. Calibration data cannot be collected with rain, snow or ice present on the line because this increases conductor weight by 1-4%. The line should be de-energized a minimum of four hours to allow the conductor to reach ambient temperature and to allow for a sufficient temperature spread to be used for calibration. The ICW application will log the tension, temperature, and line loading data required for calibration. This data is then sent to TVG for generation of calibration coefficients.

For maximum accuracy, the line should be taken out of service a second time, at an ambient temperature at least 20 degrees C different from the first time. Typically this is done in the opposite season from that present during installation.

4 Project Results

The following subsections specifically address the technical results, lessons learned, and technology/knowledge transfer plan for the project.

4.1 Technical Results, Findings, and Recommendations

Although the project was cancelled before construction to install the equipment started, some initial studies were conducted. The main study that was conducted was a Path line-of-site survey that is essential to the success of communication. Poles M3-P4, M3-P7 and M4-P2 we surveyed for line-of-site with the antenna mounted on the transmission tower at Barre substation. It was determined that all three paths are obstructed by vegetation, which could potentially introduce interference in communication.

4.2 Technical Lessons Learned

As a result of all the efforts that were put into this project, it has been uncovered that the Transmission Line monitors require direct line-of-site in between communication boxes to bring the signals back from the transmitter device back to the substation. Unless the critical spans of the monitored line are close to a substation where an RTU installed, it may not be feasible to get a communication path back to EMS. In addition, longer lines will require a lot of routing devices to carry the signal back to the RTU, which makes the solution not practical with the significant increase in equipment, cost, and maintenance of devices.

4.3 Value Proposition

It has been determined from this project that although Dynamic Line Ratings might be feasible in some specific occasions, the adoption of technology with the current operating procedure is not practical. The solution proposed by this technology is not practical for deployment at the high voltage transmission system, given that longer lines will require significant increase in cost, equipment and maintenance. As for the sub-transmission adoption of technology, most of the heavily loaded sub-transmission lines are in residential areas where the establishing communication path would be extremely hard, giving the obstacles blocking the line-of-sight between communication devices.

4.4 Technology/Knowledge Transfer Plan

Findings have been shared with project stakeholders, including Transmission Engineering and Grid Operations. Testing results and preliminary finding have been communicated to the rest of the team, and documented in the project folders. Final closing report was developed and shared with the project team.

5 Metrics

None

6 Appendix

List of Acronyms

ARRA	American Reinvestment and Recovery Act
AT	Advanced Technology (the organization)
ATP	Advanced Technology Procedure, or Authority to Proceed
BOM	Bill of Materials
CCB	Change Control Board
CMO	Compliance Management Office
COTS	Commercial Off-The-Shelf
CPUC	California Public Utilities Commission
DBE	Disadvantaged Business Enterprise
DLR	Dynamic Line Rating
DOE	Department of Energy
eDMRM	electronic Data Management/Records Management
EPIC	Electric Program Investment Charge
FY	Fiscal Year
GRC	General Case
IAW	In Accordance With
ICC	Integrated Change Management
IO#	Internal Order Number
IP	Intellectual Property
O&M	Operations and Maintenance
PDF	Portable Document Format (Acrobat file)
PfMP	Portfolio Management Plan
PM	Project Manager
PMBOK	Project Management Body of Knowledge
PMI	Project Management Institute
PMO	Portfolio Management Office
PMP	Project Management Plan
PMR	Portfolio Management Review
PO	Purchase Order
PPM	PMO Process Matrix
PPP	PMO Procurement Plan
PRR	PMO Risk Register
PSR	Project Status Review

SCE	Southern California Edison
SME	Subject Matter Expert
TFC	Termination for Convenience
TL	Technical Lead
TLM	Transmission Line Monitors
Ts&Cs	Terms and Conditions

Glossary

Term to define Definition here

Also see glossary's available for the electric utility industry available on the internet like this one: http://www.nwppa.org/advertise_sponsor/Facts_Figures_Glossary_of_Terms.aspx)

Appendix C

Advanced Technology ID# FT-14-004 Enhanced Infrastructure Technology Evaluation

Final Project Report

Advanced Technology
ID# FT-14-004 Enhanced Infrastructure Technology Evaluation

Final Project Report

Developed by

SCE Transmission & Distribution, Advanced Technology Organization

SCE Advanced Technology PMO
14799 Chestnut St.
Westminster, CA 92683

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1 Executive Summary

The goal of this project was to evaluate the effectiveness of an improved vault blower. Vault blowers are used to keep distribution vaults, containing transformers, at an acceptable ambient temperature. The approach involved examining issues with current ventilation systems, developing a new equipment specification addressing these limitations, and field demonstrating a prototype built to these new specifications. Both the performance and cost of the new blower are favorable. So, a recommendation has been made to SCE's Distribution Apparatus Engineering group to adopt this new vault blower specification.

This project was funded by EPIC I.

2 Project Summary

The following subsections address the key project elements.

2.1 Project Objective

Southern California Edison's (SCE) Distribution Apparatus Engineering group asked the Advanced Techology organization to investigate and develop recommendations for an enhanced, ruggedized, cost effective vault ventilation system (strengthened, longer service life blowers & related components).

2.2 Problem Statement

Data shows that SCE vault blowers last approximately 2 years then fail due to corrosion, bearing, and balancing issues. Insufficient ventilation allows vaults to overheat, shortening vault life. Average vault replacement cost is approximately $250K.

2.3 Scope

The intent of this project was to develop a specification that improved blower life, acquire and field test a prototype based on this specification, and provide recommendations to the Distribution Apparatus Engineering group and other Independently Owned Utilities.

2.4 Schedule

This project started in 2014 was complete in 2016.

2.5 Milestones and Deliverables

- Investigate current state issues 4th Qtr. 2014
- Develop hardened blower specification 2nd Qtr. 2015
- Procure prototype vault blower 4th Qtr. 2015
- Initiate pilot December 2015
- Evaluate/inspect vault blower June 2016
- Provide Recommendations to SCE Distribution Apparatus Engineering 2nd Qtr. 2016

3 Test Set-Up/Procedure

The prototype vault blower was visually inspected to ensure it met new specifications. Noise level readings were taken in a lab environment. The prototype was installed in a vault in the field for evaluation. Noise level readings were taken in the field and at the end of the field test. The blower was visually inspected at the end of the test period (six months) for corrosion. It remains in operation.

4 Project Results

The following subsections specifically address the technical results, lessons learned, and technology/knowledge transfer plan for the project.

4.1 Technical Results, Findings, and Recommendations

Existing blowers use motors that are not enclosed and allow moisture into the motor, use un-sealed ABEC-1 bearings, and have impellers that are balanced to grade G 6.3. Key features of the hardened blower specification are: severe duty totally enclosed fan cooled motor (IEEE 841 or equivalent), double sealed ABEC-5 grade bearings, impeller balanced to a higher quality grade G 2.5, and stainless steel louver rivets.

After six months in service, the blower showed no signs of corrosion, the noise level reading stayed consistent at 85 dB (install vs. 6 months later) which is indicative that bearings & balancing are as installed. Based on these results, SCE is confident that use of a hardened blower will significantly reduce the meant time between failure (2 years).

Based on our engineering judgement, test results and evaluation, we expect that the new hardened vault blower could last up to 10 years. We recommend standardizing the new blower going forward. We also recommend that Engineeeering continues to monitor and track the performance of the new blower to find out its true lifespan.

4.2 Technical Lessons Learned

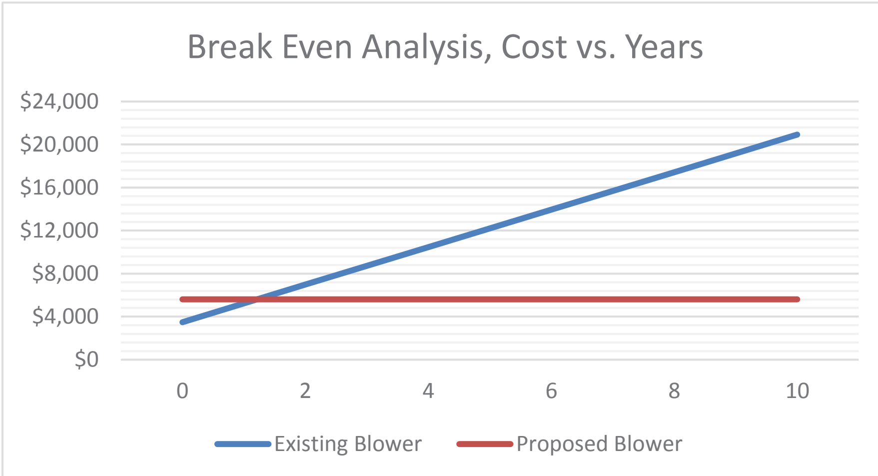
NA

4.3 Benefit Analysis

Utilizing hardened blowers in SCE distribution vaults will lower O&M and Capital costs and contribute to minimizing premature asset degradation (see analysis below). Existing blowers cost approximately $2,487 and last approximately two years. The hardened blower procured for this demonstration cost $4,613. The labor to install a blower is the same for either blower; about $1,000.

The table below shows the cost of the new and old blower over a ten year period, and an expected savings (benefit) of $7,822 (without inflation). Furthemore, the cost of the new blower is recovered in year 3.

Year	$ Old Blower	$ New Blower	Benefit
1	$ 2,487	$ 4,613	$ (2,126)
2	$ 2,487	$ 4,613	$ (2,126)
3	$ 4,974	$ 4,613	$ 361
4	$ 4,974	$ 4,613	$ 361
5	$ 7,461	$ 4,613	$ 2,848
6	$ 7,461	$ 4,613	$ 2,848
7	$ 9,948	$ 4,613	$ 5,335
8	$ 9,948	$ 4,613	$ 5,335
9	$ 12,435	$ 4,613	$ 7,822
10	$ 12,435	$ 4,613	$ 7,822



4.4 Technology/Knowledge Transfer Plan

Recommendations were made to upgrade the existing vault blower specification to the new hardened vault blower specification. The hardened vault blower is not an SCE proprietary piece of equipment and can be procured by other utilities from the vault blower manufacturer, or procured via competitive procurement. SCE expects the cost to go down with large procurements.

5 Metrics

The new hardened vault blower should last significantly longer than the unit currently used by SCE and result in significant savings.

Appendix D

Advanced Technology 2013009 - Submetering Phase 1 Pilot

Final Project Report

Advanced Technology
2013009 - Submetering Phase 1 Pilot
Final Project Report

Developed by

SCE Transmission & Distribution, Advanced Technology

Organization

SOUTHERN CALIFORNIA EDISON®

An EDISON INTERNATIONAL® Company

Disclaimer

Acknowledgments

Prepared for:

Customer name and Address

Prepared by: Al Shepetuk, CP&S/Product development & Division Management, Demonstrations & Pilots

Principle Investigators (s)

Change Log

Version	Date	Description of Change	Project Report No.
0.01	201402xx	Annotated Outline	TC/PS/FE-XX-XXX-TRXX

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Preface

1 Executive Summary

Summary

On 11/14/13, the California Public Utilities Commission (CPUC) voted to approve the revised Proposed Decision (PD) Modifying the Requirements for the Development of a Plug-In Electric Vehicle Submetering Protocol set forth in D.11-07-029. The investor-owned utilities (IOUs), Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE) were directed to implement a two phased pilot beginning in May 2014, with funding for both phases provided by the Electric Program Investment Charge (EPIC). In addition to helping meet regulatory requirements, this pilot supports “smart charging” components associated with the integration of electric transportation in a smart grid environment.

The Phase 1 Pilot was available to a maximum of 500 eligible PEV participating submeters within SCE’s service territory. All residential and commercial customers could participate except streetlight customers and customers taking Direct Access, Electric Service Provider, and Community Aggregation service.

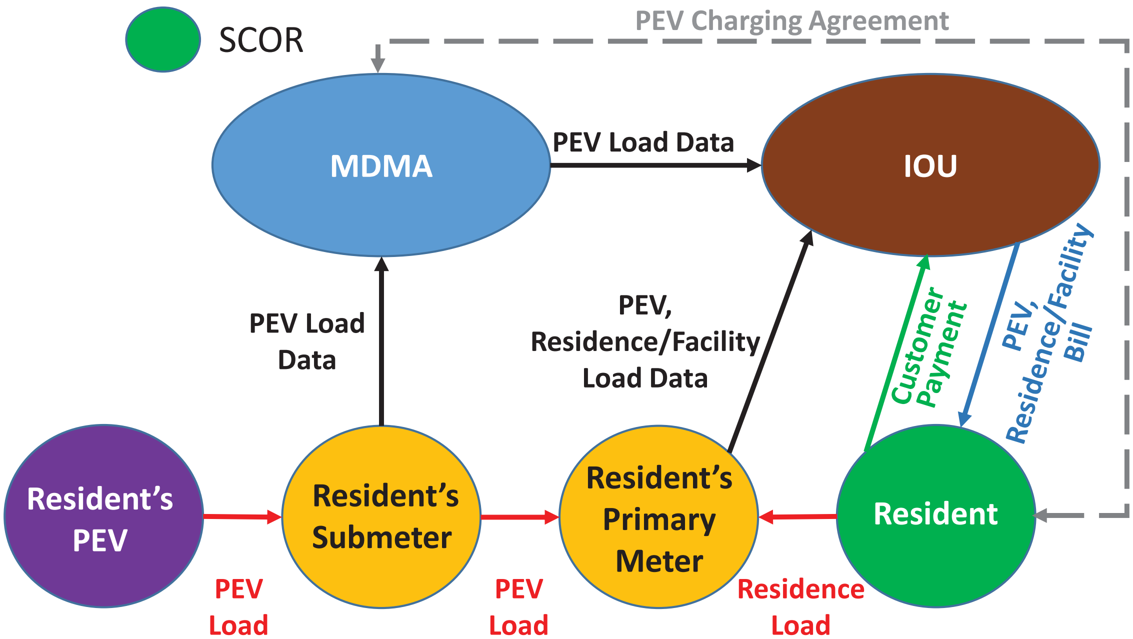
Eligible customers (single customers-of-record) charged a plug-in electric vehicle which was measured by a submeter (submeter load) and was connected to the same meter that registers the customer’s primary load. The submeter load was manually subtracted from the customer’s primary meter load and billed, each month, on SCE’s applicable electric vehicle rate schedule. Eligibility conditions required that customers have an interval data recorder type meter as their primary meter. The PEV submeter was used for the sole purpose of measuring electricity used to charge the PEV. Examples of residential and commercial EV charging are shown below in Figures 1 & 2 respectively. Submeter processes are shown in Figures 3 and 4 on the next page.

Figure 1

Figure 2

Figure 3

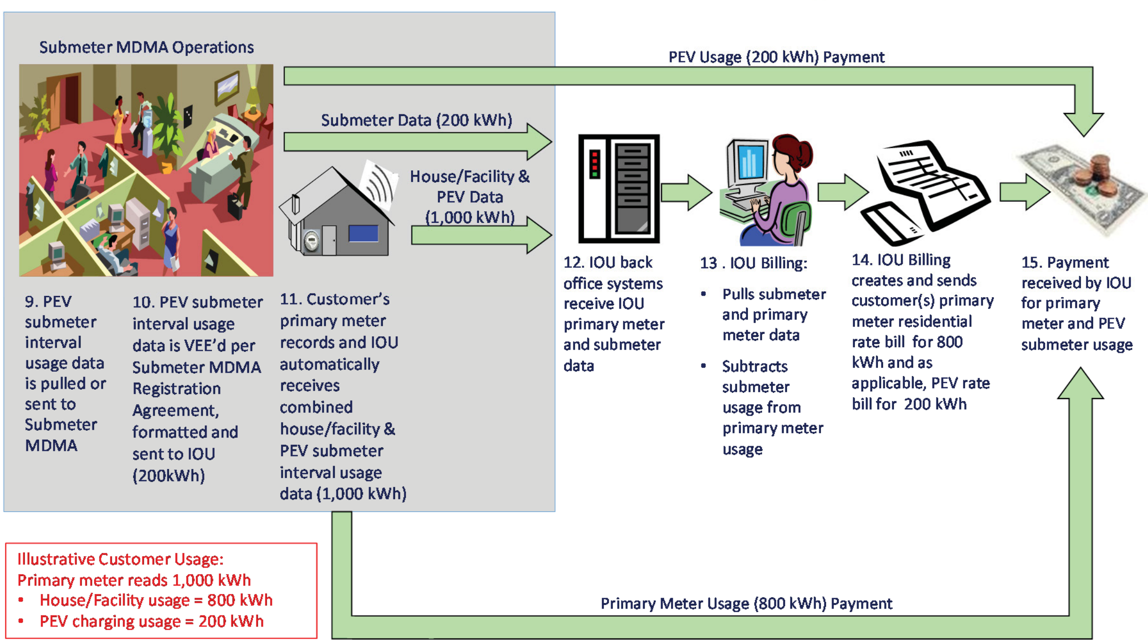
Submeter Energy, Data, Bill and Payment Process
Single Family Resident/Commercial Facility[1] Resident



[1] Facility includes residents in MUD, condo complex or commercial facility

Figure 4

Submeter Pilot Data Collection – Billing



A Submeter Meter Data Management Agent (Submeter MDMA) was responsible for enrolling customers with PEVs into the Phase 1 Pilot program. Submeter MDMAs were selected by the Energy Division. IOUs had no role in the approval process.

The Energy Division CPUC ordered IOUs to competitively solicit and select and independent third-party Phase 1 Pilot evaluator. The IOUs selected Nexant from among three proposals.

On July 10, 2014, in compliance with Decision (D.) 13-11-002 and Resolution E-4651, the IOUs filed new tariffs to implement Phase 1 of the Pilot by establishing Schedule PEVSP, Plug-In Electric Vehicle Submetering Pilot (Phase 1), and associated customer and Submetering Meter Data Management Agent (MDMA) agreements.

Seven to ten potential submeter MDMAs participated for all or part of the development of the Phase 1 Pilot requirements form July 2011 to July 2014. Only three companies applied and all were approved to provide Submeter MDMA services during the Phase 1 Pilot. They included:

- eMotorWerks (eMW)
- NRG EVgo (NRG)
- Ohmconnect

On September 1, 2014, the six-month enrollment period began. By December 17, 2014, no Customer Enrollment Agreement (CEA) had been accepted by the IOUs. Accordingly, the IOUs and MDMAs requested and received approval for an extension of six months to comply with February 28, 2015 deadline in Resolution E-4651 for ending the Phase 1 Submetering Pilot open enrollment period

Results

The initial 6-month enrollment period ended on February 28, 2015 with no Customer Enrollment Agreement (CEA) accepted by SCE. Over the next six-month enrollment period ending on August 31, 2015, the Submeter MDMAs enrolled a total of 92 (18.4%) residential submeters of a maximum of 500 submeters in the Phase 1 Pilot in SCE's territory.

The period of performance for this project was 34 months which includes Pilot preparation. Total expenditures were $1.03M (As of 10.30.16) vs. a budget of $2.195M*. (Note: Report can be updated when December 2016 financial report is published in February 2016 with actual FINAL Pilot cost.)*

Lessons Learned

Lessons learned that will be applied to the Submetering Phase 2 Pilot include:

1. The Submeter MDMAs were not prepared to start the Phase 1 Pilot on September 1, 2014.

   Require more stringent preliminary ED review of stakeholder's qualifications to be a Submeter MDMA including final approval by the IOUs that Submeter MDMA candidates meet all requirements stated in Advice Letter prior to the start of the Pilot.

   In addition, provide the Submetering MDMAs with more comprehensive, detailed training prior to the start of the Phase 2 Pilot to help improve their performance and level of customer satisfaction.

2. The manual customer enrollment process was challenging for our customers and the Submeter MDMAs.

   Streamline the customer enrollment process by simplifying the Customer Enrollment Agreement (CEA); replacing the Phase 1 Excel spreadsheet tracker used to record customer status throughout the Pilot with a more robust, more flexible Access database; and provide the Submeter MDMAs more details when a CEA is returned to them for correction.

3. The term submeter 'accuracy' is equivalent to the same term used in the ANSI C-12 standard or equivalent to 'tolerance' in NIST Handbook 44 Section 3.40 T.2. Require the submeter to demonstrate meter acceptance accuracy of +/-1%, and maintain accuracy of +/- 2% during the Phase 2 Pilot. Submeter MDMA is responsible for describing how they comply with this accuracy requirement prior to pilot installation.

4. Require the submeter's time be synchronized to the Universal Time Coordinate (UTC) time standard as defined by the National Institute of Standards and Technology (NIST), and be within +/- two (2) minutes of UTC, while the EVSE is in service. Submeter MDMA is responsible for describing how they comply with this accuracy requirement prior to pilot installation.

2 Project Summary

On June 27, 2014, the CPUC issued Resolution E-4651, which approved SCE's request to implement a Plug-In Electric Vehicle Submetering Pilot (PEVSP) in compliance with Decision 13-11-002, in which the Commission ordered the implementation of Submetering pilots to understand the requirements of and customer experiences with non-utility plug-in electric vehicle submetering. Upon this Decision, SCE procured contract project management support (Corepoint and Choice Workforce), launched the Phase 1 Pilot announcement on SCE's plug-in electric vehicle (PEV) website, collaborated with PG&E and SDG&E on an Request for Proposal to identify a third-party evaluator, set-up internal processes and training documentation, began working with Submeter MDMAs (i.e., eMotorWerks, NRG and Ohmconnect) selected by the Energy Division (ED), received CPUC approval of the Submetering Pilot tariff, and officially started the Phase 1 Pilot on September 1, 2014.

The three Submeter MDMAs, were issued purchase orders to enable SCE to pay the MDMAs for enrolling customers and providing SCE with monthly EV submeter usage data. Nexant was selected by the three IOUs to be the third party evaluator of the Submetering Pilots. PG&E contracted Nexant on behalf of the three IOUs who will share the costs equally, 33% each, as mandated by the CPUC. SCE's Phase 1 Pilot share was $220,000 which was payable annually through 2016 for the Phase 1 Pilot. SCE's actual Phase 1 Pilot Nexant cost was $120,264.

Ohmconnect and eMotorWerks started the Pilot without a UL certified submeter. NRG's submeter had met UL safety requirements but NRG was still testing its internal submeter communications as the Pilot started. Consequently, SCE did not receive any Customer Enrollment Agreements from any of the MDMA's during the six-month enrollment period. The IOUs and the Commission's ED then held a series of meetings with the participating MDMAs to understand the issues that were preventing the MDMAs from enrolling any customers. The MDMAs requested an extension of the customer enrollment period to allow additional time to obtain submeter Underwriters Laboratories (UL) certification and meet all other Pilot requirements including additional time to complete CEAs, pass submeter communications testing, and establish accounts at each IOU to receive incentive payments.

In December 2014, the ED requested that the IOUs develop a draft Contingency Plan to possibly extend the Phase 1 Pilot. The Plan was submitted to Energy Division on January 20, 2015. Subsequently, the ED directed the IOUs to send the CPUC Executive Director a Phase 1 Submetering Pilot letter requesting an extension before the end of February 2015. SCE worked closely with the CPUC/ED and Submetering MDMAs to extend the Phase 1 Pilot six months to August 31, 2015, resulting in the enrollment of enroll 92 customers.

The initial 6-month enrollment period ended on February 28, 2015 with no Customer Enrollment Agreement (CEA) accepted by SCE. Over the next six month enrollment period, ending August 31, 2015 the Submeter MDMAs enrolled a total of 92 residential submeters of a maximum of 500 submeters in the Phase 1 Pilot in SCE's territory as shown in Table 1 below.

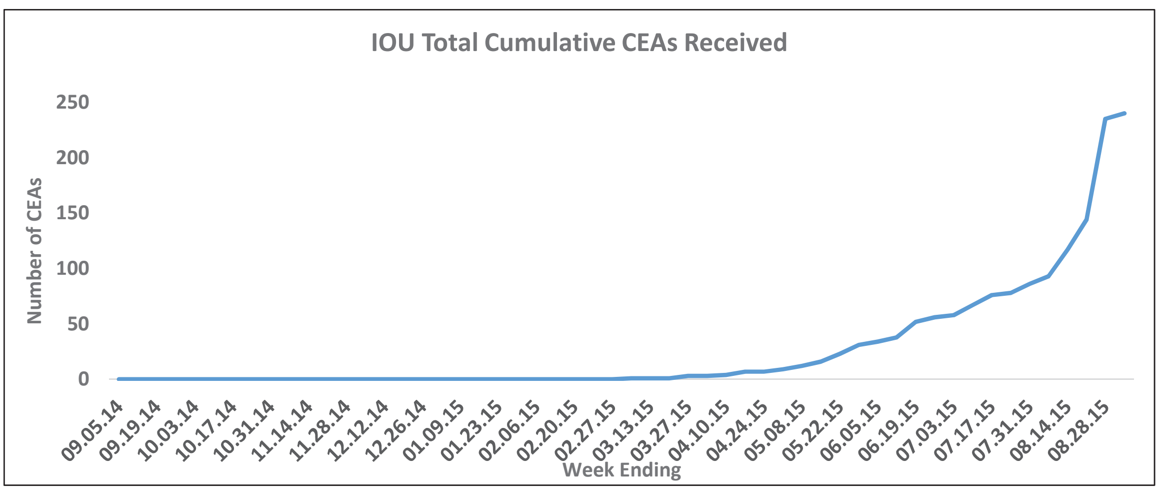
Table 1

Number of Submeters by IOU & Submeter MDMA

IOU	EMW	NRG	OMC	Total	IOU Max	Percent
PG&E	108	1	22	131	500	26%
SCE	71	2	19	92	500	18%
SDG&E	12	1	4	17	500	3%
Total	191	4	45	240	**1,500**	**16%**
Percent	**80%**	**2%**	**19%**	**100%**		

154 of 240 (64%) CEAs were received in last month of the 12-month enrollment period as shown in Figure 3 below overloaded IOU manual processes.

Figure 5



During the Pilot, SCE provided its customers with manual subtractive billing to separately bill household and EV charging on their respective rates. The three IOUs all experienced billing problems due to various accuracy and timing problems with the MDMAs' submeters. Synching the submeter to the U.S. time standard as defined by the National Institute of Standards and Technology or within three minutes of the time used by the utilities appears to be the bigger issue and the cause of most recorded submeter "Bad" intervals which occur when the submeter kWh exceeds the primary meter kWh. (See Section 4.2 Technical Lessons Learned for further details)

SCE also supported its customer's Pilot participation by answering their questions and resolving their issues. SCE provided a similar service to the three Submetering MDMAs. The Phase 1 Submetering Pilot customer participation ended on schedule and under budget.

Customer satisfaction key Learnings from Nexant's customer surveys during the Phase 1 Pilot across the three IOUs follows:

- 78% of respondents said they were extremely or somewhat satisfied with their overall submetering service
- 82% of respondents said they would recommend submetering services to a friend or colleague based on their Phase 1 Pilot experience
- 77% said they would be interested in participating in the Phase 2 pilot
- Customers participating in the Phase 1 Pilot reported charging their EV during off-peak hours 90% of the time vs 48% before the Pilot.
- Median perceived customer charging savings was $30 per month, equivalent to 43% savings
- 30% of surveyed customers experienced a significant number of billing issues caused by inaccurate submeter data and poor customer service from their Submeter MDMA (Note: Phase 1 Pilot customers were not provided bill guarantee to ensure that they would not be financially penalized for participating in the Pilot.)

2.1 Project Objective

Decision 13-11-002: During Phase 1, the utilities tested the use of Single Customer of Record submetering. Single Family Homes, Apartment Units, and Commercial Facilities were allowed to use submetering under a Single Customer of Record. However, the Submeter MDMAs did not enroll any commercial customers in SCE's territory.

Primary goals of the Phase 1 Pilot were to:

- Evaluate the demand for Single COR submetering in Single Family Homes, Apartment Units, and Commercial Facilities, and customer uptake prior to making larger investments.
- Ensure a positive Customer Experience while determining customer perceptions, estimating customer costs and benefits of Single COR submetering-enabled services, and smoothly transitioning between tariffs.

2.2 Problem Statement

- CPUC issued an AFV OIR Phase 2 Decision mandating the California IOUs develop methods enabling third parties—current utility customers and/or providers of electric vehicle (EV) services—to submeter the EV load to reduce customer cost related to installing a dedicated meter for EV charging.
- Decision13-11-002, dated November 14, 2013, adopted the Energy Division Staff PEV Submetering two-phase pilot project.
- Resolution E-4651, dated June 26, 2014, approved the utilities' Schedule Plug-In Electric Vehicle Submetering Pilot tariff with modifications for Phase 1.

- SCE's Tier 2 Advice Letter, ADVICE 3075-E, dated July 10, 2014, established Schedule PEVSP, Plug-In Electric Vehicle Submetering Pilot and associated forms to support the implementation of the Submetering Phase 1 Pilot.
- IOUs and MDMAs requested and received approval for an extension of six months to comply with February 28, 2015 deadline in Resolution E-4651 for ending the Phase 1 Submetering Pilot open enrollment period.

2.3 Scope

1**. Pilot Term:** Phase 1 duration was 18 months beginning September 1, 2014 and ending February 28, 2016. The IOUs were directed by the Energy Division to extend the Phase 1 Pilot six months to August 31, 2016 for a total of 24 months.

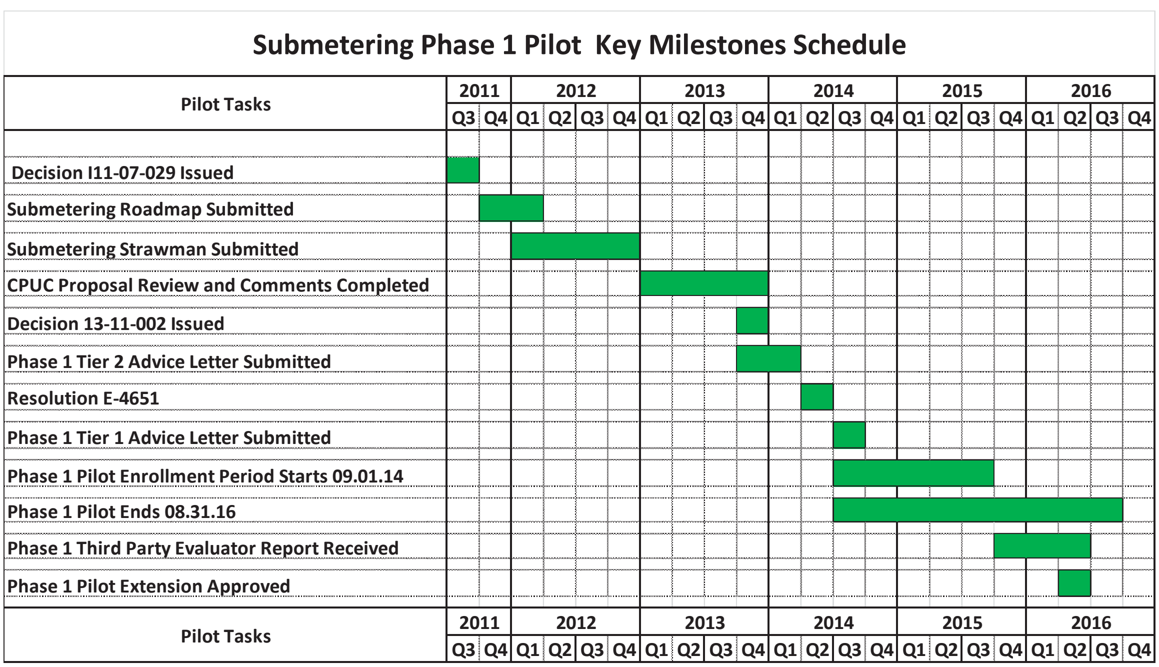
2. **Pilot Participation Cap:** On a first-come, first-served basis, a maximum of 500 submeters could have been enrolled in the Phase 1 Pilot. Of the 500 submeters, a limit of 100 submeters could have been related to NEM accounts.

3. **Pilot Participation Period:** Customers were allowed to participate for up to a maximum of 12 consecutive billing cycles. Customers were able to unenroll from the Pilot at any time, but could not re-enroll in Phase 1 of the Pilot unless they were relocating in one of the IOU's service territories.

2.4 Schedule

Shown in Figure 6 below

Figure 6



2.5 Milestones and Deliverables

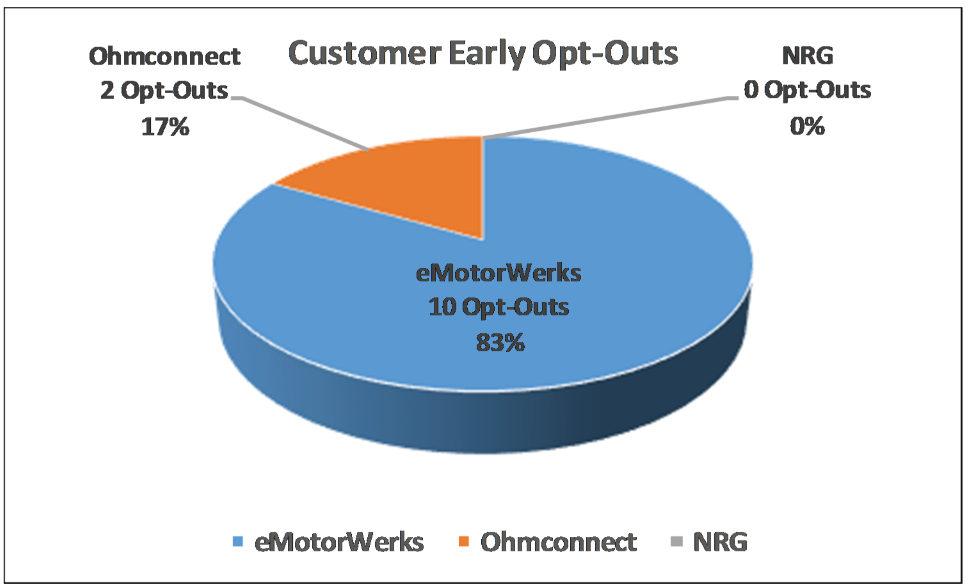
Milestones:

See Section 2.4 above – Submetering Phase 1 Pilot Key Milestones Schedule above schedule

Deliverables:

1. **Customer Enrollment**
   SCE enrolled and supported 92 residential submeter customers including 13 NEM accounts were limited to a maximum of 12 billing cycles.
   a. 78 0f the 92 enrolled customers completed their maximum of 12 billing cycles.
   b. 14 (15.2%) customers opted to terminate their participation early.
      i. Two customers moved out of SCE's territory.
      ii. The remaining twelve customers left the Pilot primarily due to EV charging cost that did not meet their expectations as shown on next page in Figure 7.

Figure 7



2. **Manual Subtractive Billing Procedure**
   A process in which the SCE billed EV usage separately from other usage. All usage was first measured through the primary meter, while the Electric Vehicle usage was also measured by a dedicated submeter. The Electric Vehicle usage was subtracted from the usage measured by the primary meter to bill the house consumption and the Electric Vehicle consumption separately as illustrated below in Figure 8.

Figure 8

Time Interval	Submeter kWh	Primary Meter kWh	Net Primary Meter kWh
11:00 - 11:15	3	7	4
11:15 - 11:30	5	9	4
11:30 - 11:45	2	5	3

3. **Nexant Third Party Evaluation Phase 1 Report**
   The Phase 1 Initial and Final Reports covered the customer-experience evaluation, Submeter MDMA business models, submeter accuracy and Phase 1 conclusions and recommendations. Copies of the Nexant reports are attached below..

   Interim Nexant Phase Pilot 1 Pilot Report

   California Statewide PEV Submetering Pilo   PEV Submetering Post-Pilot Survey Resı

3 Test Set-Up/Procedure[1]

Testing of the submeter's accuracy was performed independently by Nexant, the third party evaluator. As part of the Phase 1 evaluation, Nexant installed data loggers for a sample of 34 submeters at participating customers' premises for the period December 14, 2015 through February 12, 2016 to independently measure PEV charging loads. The accuracy sample included 31 eMotorWerks (eMW) submeters and three NRG submeters.

Data collected from the loggers was compared to submetering data over the same period to assess the accuracy of the submeters. During the data collection period, however, eMW experienced server-side data processing software issues that caused erroneous

December 2016 financial report will be published in February 2016 with FINAL Pilot cost. Measurements for 16 to 24% of PEV charging loads for some pilot participants. The most serious issue occurred as an unintended side effect of eMW's server migration that took place on October 26, 2015 causing a 24 hour shift for some 15 minute data intervals. eMW was notified of the problem in December 2015 through customer complaints of overbilling1 and resolved the issue on January 8 and 9 via fixes to the server. Because of this known issue and the fact that any measurement errors resulting from affected loggers would have overwhelmed the 5% accuracy threshold, the analysis dataset was split into two periods—December 14, 2015 through January 8, 2016 and January 9 through February 12, 2016. Unless otherwise stated, the results and figures presented in this section utilize the second half of the study period when the eMW software issue was not a concern.

In addition to the server malfunction, eMW also reported two submeters in the accuracy sample that had sporadic data coverage and one that was completely offline during the study period. Due to the missing data, these submeters would not have met the 5% accuracy requirement and were dropped from the analysis. Nexant also experienced some attrition in its logger sample due to technical and fielding issues. Out of the initial sample of 34 loggers, 3 were not usable because the amps recorded by the logger could not be converted to kW, 2 stopped recording data in the middle of the study period, 2 did not pass data validation checks, and 11 were installed without properly synchronizing the logger clock with the smart meter or submeter clock. Combining the remaining 16 loggers with the eMW/NRG submeters with reliable data resulted in 14 logger-submeter pairs that were available for analysis.

Based on the results of the various equivalence tests, most submeters for which data was available meet the 5% accuracy threshold specified by Phase 1 of the pilot. However, one submeter in the sample was offline for a portion of the study period and a second incorrectly allocated some usage to the peak and partial peak periods during the simulated billing cycle. In addition, the results should be caveated by the fact that 4 out of 31 eMW submeters in the analysis sample were not included in the analysis due to data issues and half of the analysis period was affected by a software malfunction that caused data errors for some eMW customers. These measurement errors would certainly have affected customer bills and may account for some of the dissatisfaction customers expressed about billing accuracy.

[1] Source: Nexant, Inc. – California Statewide PEV Submetering Pilot Phase 1 Report

4 Project Results

4.1 Technical Results, Findings, and Recommendations

The Phase 1 Pilot's technical results, key findings, and recommendations are focused on the performance of the Submeter MDMAs' submeters. The submeters' accuracy of ± 5% and related synchronization errors created unacceptable submeter data errors resulting in significant customer billing issues.

4.2 Technical Lessons Learned

Issue: Billing issues occurred during the Phase 1 Pilot due to differences in submeter and SCE meter accuracy, ± 5% vs, ± .5% respectively, and submeter synchronization errors.

The three IOUs all experienced varying accuracy problems with the MDMAs' submeters. However, synching the submeter to the U.S. standard as defined by the National Institute of Standards and Technology or within three minutes of the time used by the utilities appears to be the bigger issue and the cause of most recorded submeter "Bad" intervals which occur when the submeter kWh exceeds the primary meter kWh. See Section 5.5 for discussion of bad interval impact on customers.

Lesson Learned: (To be applied to the Phase 2 Pilot)

1. (The term ‘accuracy’ is equivalent to the same term used in the ANSI C-12 standard or equivalent to ‘tolerance’ in NIST Handbook 44 Section 3.40 T.2.) Require the submeter to demonstrate meter acceptance accuracy of +/-1%, and maintain accuracy of +/- 2% during the Phase 2 Pilot. Submeter MDMA is responsible for describing how they comply with this accuracy requirement prior to pilot installation.

2. Require the submeter’s time be synchronized to the Universal Time Coordinate (UTC) time standard as defined by the National Institute of Standards and Technology (NIST), and be within +/- two (2) minutes of UTC, while the EVSE is in service. Submeter MDMA is responsible for describing how they comply with this accuracy requirement prior to pilot installation.

4.3 Value Proposition

Primary Principles:

- Greater reliability: Not applicable
- Lower costs:

  Many Submetering Phase 1 Pilot participants enrolled to save energy cost. For example, a customer on residential rate plan Schedule D in Tier 3 pays $.29/kWh to charge their EV. Pilot participants charging their EV during off-peak paid $.14/kWh. The average SCE EV owner's EV charging monthly load on SCE’s separate meter TOU-EV-1 rate was 345 kWh resulting in a potential savings of $51.75/month.

- Increased safety and/or enhanced environmental sustainability:

  Hybrid Plug-in Electric Vehicles and Battery Electric Vehicles enhanced environmental sustainability by reducing pollutants.

Secondary Principles: *[Project may promote these areas, but not required]*

- The Loading Order: Not applicable
- Low-Emission Vehicles/Transportation:

  SCE developed methods enabling third parties—current SCE customers and/or providers of electric vehicle (EV) services—to submeter the EV load to reduce customer cost related to installing a dedicated meter for EV charging thereby supporting the growth of electric vehicles while enhancing environmental sustainability.

- Safe, Reliable, and Affordable Energy Services:

  See Lower Cost section under Primary Principles above.

- Economic Development: Not applicable
- Efficient Use of Ratepayer Monies: Not applicable

4.4 Technology/Knowledge Transfer Plan

There are three possible means to transfer technology/knowledge:

1. This document, the Phase 1 Pilot Final Project Report documents technical results, finding, recommendation and lesson learned.

2. Presentation of the Phase 1 Pilot Final Project Report highlights technical results, finding, recommendation and lesson learned.

3. At the conclusion of the Phase 2 Pilot the CPUC will determine if the IOUs will be directed to develop and submit the Submeter Protocol. If required, the Protocol would incorporate a technology/knowledge transfer of results of both pilot phases to apply to future submetering applications. The Protocol would also include the cost and schedule to automate key Pilot processes such as enrollment and subtractive billing.

4. In addition, Nexant, the independent third party evaluator, has provided an Interim and Final Phase 1 Report. Nexant will also provide a final Report on both phases of the submetering Pilot at the end of Phase 2. This report will include a report on any technology/knowledge transfer of results of both pilot phases to apply to future submetering applications.

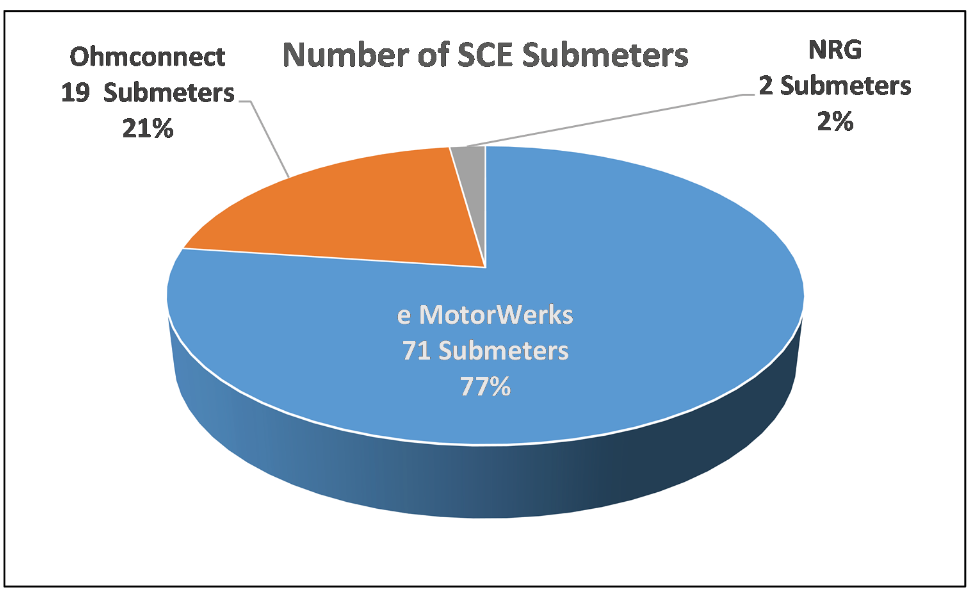
5 Metrics

5.1 Total number of SCE customer Phase 1 Pilot participants:

SCE enrolled 92 (18%) of the total 500 maximum submeters as shown in Figure 6 below:

a. eMotorWerks enrolled 71 (77%) of total SCE participants
b. Ohmconnect enrolled 19 (21%) of total SCE participants
c. NRG enrolled 2 (2%) of total SCE participants

Figure 8

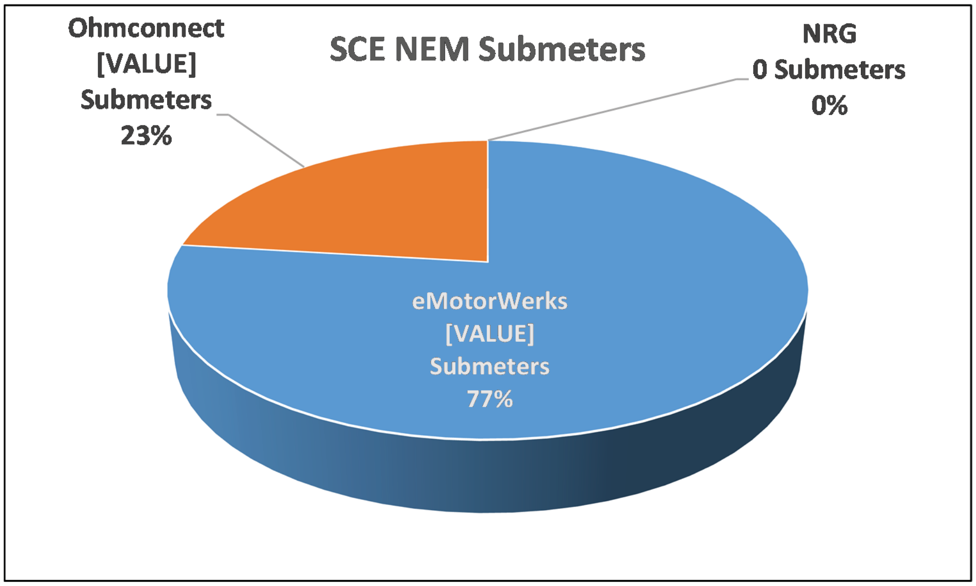


5.2 Number of SCE NEM customer participants:

SCE had 13 (13%) of the total 100 maximum NEM submeters of the 500 submeter limit as shown in Figure 7 below:

a. eMotorWerks enrolled 10 (77%) of total SCE NEM participants
b. Ohmconnect enrolled 3 (23%) of total SCE NEM participants
c. NRG enrolled 0 (0%) of total SCE participants

Figure 9



5.3 Complete and accurate Customer Enrollment Agreements:

SCE returned 56 (60.9%) of the 92 Customer Enrollment Agreements received from the Submeter MDMAs due to incomplete, inaccurate or corrected information as shown in Figures 8 and 9 below:

a. SCE returned 39 (55%) of 71 CEAs submitted by eMotorWerks
b. SCE returned 11 (65%) of 17 CEAs submitted by Ohmconnect
c. SCE returned 1 (50%) of 2 CEAs submitted by NRG

Figure 10

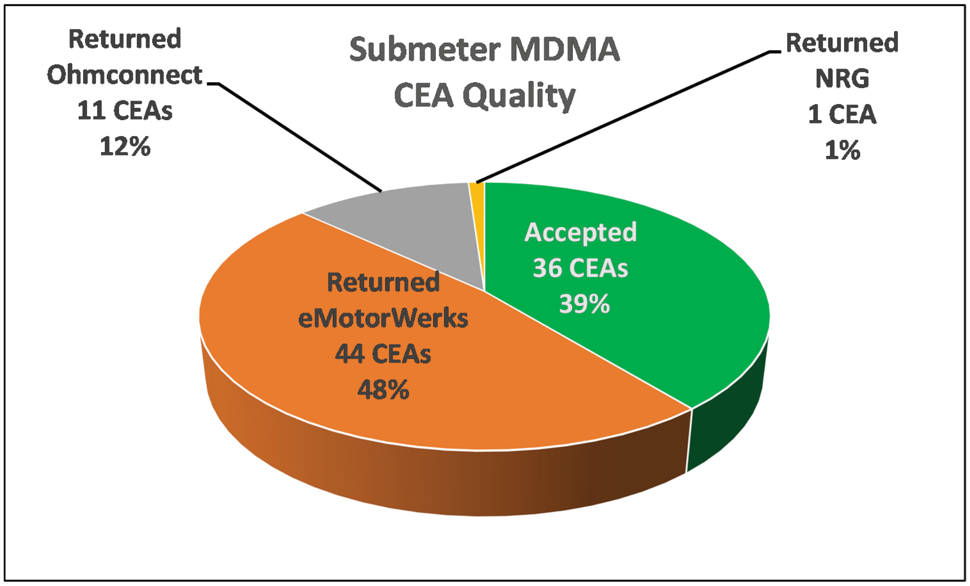
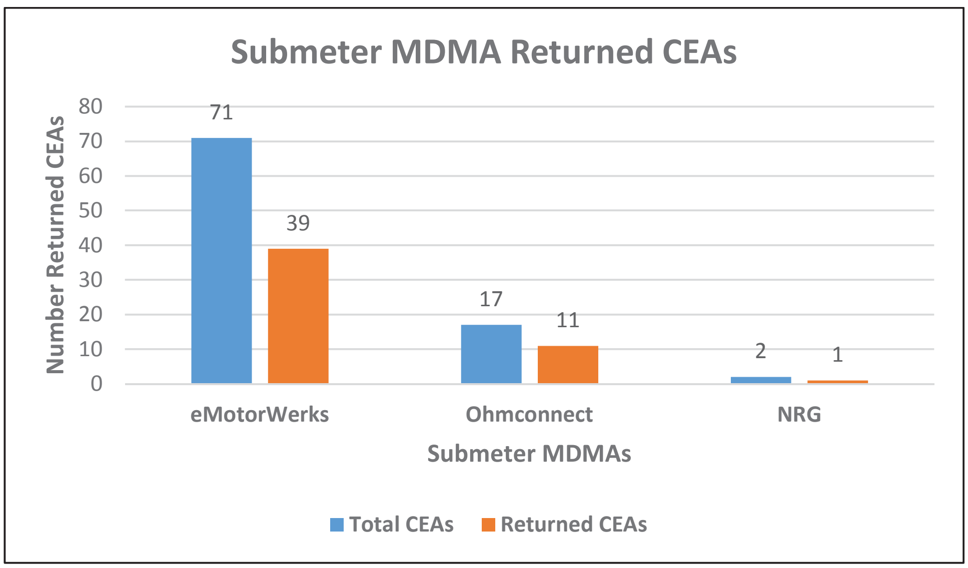


Figure 11

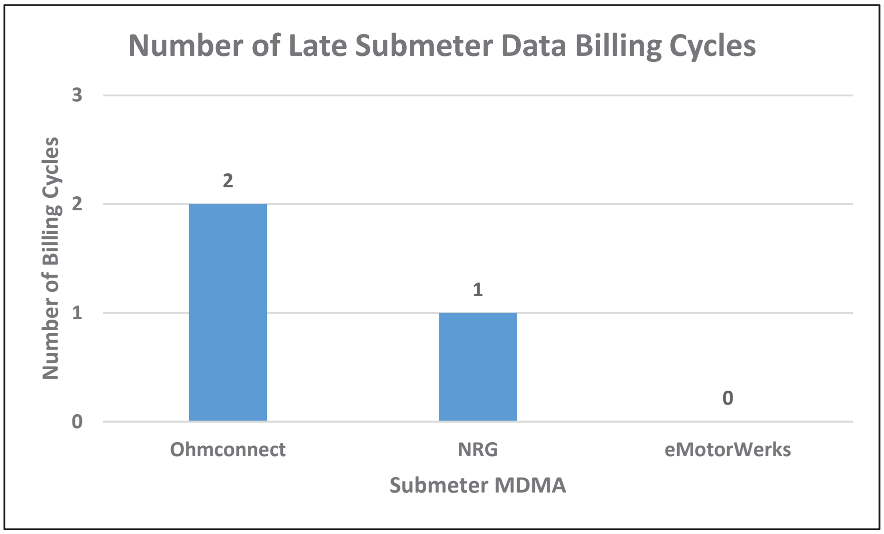


5.4 Submeter MDMA on-time delivery of customer submeter interval usage data:

Two of the Submeter MDMAs experienced problems delivering their submeter data to SCE on-time for the first few customers but subsequently delivered all monthly submeter data on-time as shown in Figure 10 below:

a. The submeter data for NRG's first SCE customer, PEV000001, was late for the customer's first two billing cycles resulting in all the EV charging billed on the customers Primary meter rate.
b. The submeter data for Ohmconnect's second SCE customer, PEV000003, was late for the customer's first billing cycle resulting in all the EV charging billed on the customers Primary meter rate.

Figure 12



5.5 Submeter MDMA accuracy of customer submeter interval usage data:

The three IOUs all experienced varying accuracy problems with the MDMAs' submeters. The IOUs expected some data quality problems caused by the accuracy differences between the IOUs' SmartMeters at ±.5% vs the submeters at ± 5%, a ten-fold difference.

- However, synching the submeter to the U.S. standard as defined by the National Institute of Standards and Technology or within three minutes of the time used by the utilities appears to be the bigger issue and the cause of most recorded submeter "Bad" intervals which occur when the submeter kWh exceeds the primary meter kWh. Bad interval reduced customer charging savings as illustrated on next page in Figure 13 and contributed to their dissatisfaction with IOU service.

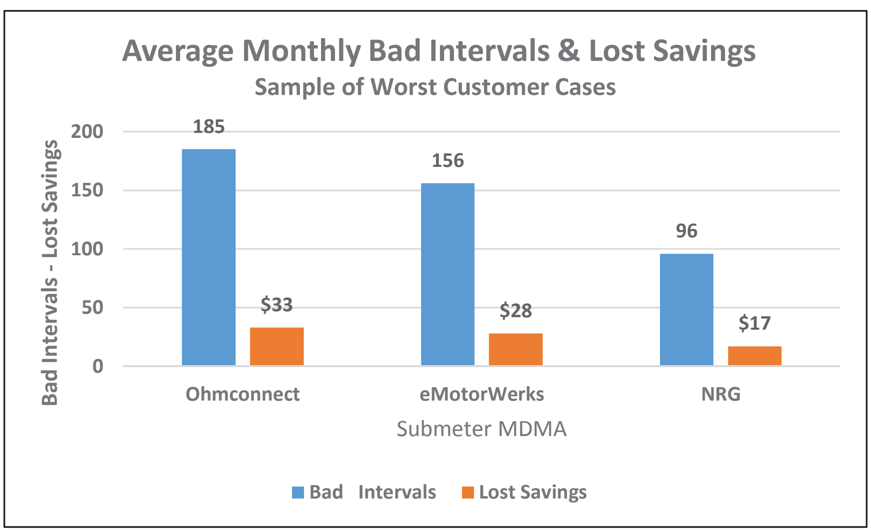
Figure 13

Time Interval	Submeter Reported kWh	Primary Meter kWh	Submeter Billed kWh	Net Primary Meter kWh
11:00 - 11:15	3	7	3	4
11:15 - 11:30	5	9	5	4
11:30 - 11:45	7	5	0	5

Worst case SCE examples are discussed and shown in Figure 11 below:

a. **Ohmconnect** customer PEV000004 averaged **185 (31%) bad intervals per month** over 12 billing cycles costing the customer on average about $33/mo. or $400/yr. *(Assumes tier 4 @ $.30 vs. TOU-EV-1 @ $.12)*
b. **EMotorWerks** customer PEV000078 averaged **156 (26%) bad intervals per month** over nine billing cycles costing the customer on average about $28/mo. or $252/yr.
c. **ERG** customer PEV000015 averaged **96 (16%) bad intervals per month** over 11 billing cycles costing the customer on average about $17/mo. or $190/yr.

Figure 14



List of Acronyms

ARRA	American Reinvestment and Recovery Act
AT	Advanced Technology (the organization)
ATP	Advanced Technology Procedure, or Authority to Proceed
BOM	Bill of Materials
CCB	Change Control Board
CMO	Compliance Management Office
COTS	Commercial Off-The-Shelf
CPUC	California Public Utilities Commission
DBE	Disadvantaged Business Enterprise
DOE	Department of Energy
eDMRM	electronic Data Management/Records Management
EPIC	Electric Program Investment Charge
FY	Fiscal Year
GRC	General Case
IAW	In Accordance With
ICC	Integrated Change Management
IO#	Internal Order Number
IP	Intellectual Property
O&M	Operations and Maintenance
PDF	Portable Document Format (Acrobat file)
PfMP	Portfolio Management Plan
PM	Project Manager
PMBOK	Project Management Body of Knowledge
PMI	Project Management Institute
PMO	Portfolio Management Office
PMP	Project Management Plan
PMR	Portfolio Management Review
PO	Purchase Order
PPM	PMO Process Matrix
PPP	PMO Procurement Plan
PRR	PMO Risk Register
PSR	Project Status Review
SCE	Southern California Edison

SME	Subject Matter Expert
TFC	Termination for Convenience
TL	Technical Lead
Ts&Cs	Terms and Conditions

Glossary

Term to define Definition here

Also see glossary's available for the electric utility industry available on the internet like this one:
http://www.nwppa.org/advertise_sponsor/Facts_Figures_Glossary_of_Terms.aspx)

Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total	Administrative and overhead costs incurred for each project
1st triennial (2012-2014)	SCE	**Integrated Grid Project** *Note: Previously referred to as Regional Grid Optimization*	Cross-Cutting/Foundational Strategies & Technologies	The project will demonstrate, evaluate, analyze and propose options that address the impacts of DER (Distributed Energy Resources) penetration and increased adoption of DG (Distributed Generation) owned by consumers on all segments/aspects of SCE's grid – transmission, distribution and overall "reliable" power delivery cost to SCE customers (all tiers). This demonstration project is in effect the next step to the ISGD project. Therefore, this analysis will focus on the effects of introducing emerging and innovative technology into the utility and consumer end of the grid, predominantly the commercial and industrial customers with the ability to generate power with self-owned and operated renewable energy sources, but connected to the grid for "reliability" and "stability" operational reasons. This scenario introduces the need for the utility (SCE) to assess discriminative technology necessary for stabilizing the grid with increased DG adoption, and more importantly, consider possible economic models that would help SCE adopt to the changing regulatory policy and GRC structures.	8/15/2012	No	Grid Operation/Market Design	$ 14,203,565	$ 17,705,291	$ 12,228,407	$ 2,634,005	$ 14,862,412	N/A
1st triennial (2012-2014)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration**	Customer Focused Products and Services	On 11/14/13, the California Public Utilities Commission (CPUC) voted to approve the revised Proposed Decision (PD) Modifying the Requirements for the Development of a Plug-In Electric Vehicle Submetering Protocol set forth in D.11-07-029. The investor-owned utilities (IOUs) are to implement a two phased pilot beginning in May 2014, with funding for both phases provided by the Electric Program Investment Charge (EPIC). This project, Phase I of the pilot will (1) evaluate the demand for Single Customer of Record submetering, (2) estimate billing integration costs, (3) estimate communication costs, and (4) evaluate customer experience. IOU's and external stakeholders will finalize the temporary metering requirements, develop a template format used to report submetered, time-variant energy data, register Submeter Meter Data Management Agents and develop a Customer Enrollment Form, and finalize MDMA Performance Requirements. The IOUs will also solicit a 3rd party evaluator to evaluate customer experience.	8/15/2012	No	Demand-Side Management	$ -	$ 1,216,459	$ 969,060	$ 157,399	$ 1,126,459	N/A
1st triennial (2012-2014)	SCE	**Distribution Planning Tool**	Energy Resources Integration	This project involves the creation, validation, and functional demonstration of an SCE distribution system model that will address the future system architecture that accommodates distributed generation (primarily solar photovoltaic), plug-in electric vehicles, energy storage, customer programs (demand response, energy efficiency), etc. The modeling software to be used allows for implementation of advanced controls (smart charging, advanced inverters, etc.). These controls will enable interaction of a residential energy module and a power flow module. It also enables the evaluation of various technologies from an end-use customer perspective as well as a utility perspective, allowing full evaluation from substation bank to customer. This capability does not exist today. The completed model will help SCE demonstrate, communicate and better respond to technical, customer and market challenges as the distribution system architecture evolves.	8/15/2012	No	Distribution	$ -	$ 1,227,244	$ 847,513	$ 378,241	$ 1,225,754	N/A

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1st triennial (2012-2014)	SCE	**Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)**	Customer Focused Products and Services	The Beyond the Meter (BTM) project will demonstrate the use of a DER management system to interface with and control DER based on customer and distribution grid use cases. It will also demonstrate the ability to communicate near-real time information on the customer's load management decisions and DER availability to SCE for grid management purposes. Three project objectives include: 1) development of a common set of requirements that support the needs of a variety of stakeholders including customers, distribution management, and customer program; 2) validation of standardized interfaces, functionalities, and architectures required in new Rule 21 proceedings, IOU Implementation Guide, and UL 1741/IEEE 1547 standards; 3) collection and analysis measurement and cost/benefits data in order to inform the design of new tariffs, recommend the deployment of new technologies, and support the development of new programs.	8/15/2012	No	Demand-Side Management	$ 2,062,026	$ 2,159,176	$ 1,215,615	$ 195,688	$ 1,411,303	N/A
1st triennial (2012-2014)	SCE	**Portable End-to-End Test System**	Grid Modernization and Optimization	End-to-end transmission circuit relay testing has become essential for operations and safety. SCE technicians currently test relay protection equipment during commissioning and routing testing. Existing tools provide a limited number of scenarios (disturbances) for testing, and focus on testing protection elements; not testing system protection. This project will demonstrate a robust portable end-to-end toolset (PETS) that addresses: 1) relay protection equipment, 2) communications, and 3) provides a pass/fail grade based on the results of automated testing using numerous simulated disturbances. PETS will employ portable Real-Time Digital Simulators (RTDS's) in substations at each end of the transmission line being tested. Tests will be documented using a reporting procedure used in the Power Systems Lab today, which will ensure that all test data is properly evaluated.	8/15/2012	No	Transmission	$ -	$ 39,564	$ 24,120	$ 15,444	$ 39,564	N/A
1st triennial (2012-2014)	SCE	**Voltage and VAR Control of SCE Transmission System**	Energy Resources Integration	This project involves the demonstration of software and hardware products that will enable automated substation volt/var control. Southern California Edison (SCE) will demonstrate a Substation Level Voltage Control (SLVC) unit working with a transmission control center Supervisory Central Voltage Coordinator (SCVC) unit to monitor and control substation voltage. The scope of this project includes systems engineering, testing, and demonstration of the hardware and software that could be operationally employed to manage substation voltage.	8/15/2012	No	Transmission	$ 87,875	$ 914,732	$ 108,733	$ 298,304	$ 407,037	N/A

Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total	Administrative and overhead costs incurred for each project
1st triennial (2012-2014)	SCE	**Superconducting Transformer (SCX) Demo**	Grid Modernization and Optimization	SCE will support this $21M American Reinvestment and Recovery Act (ARRA) Superconducting Transformer (SCX) project by providing technical expertise and installing and operating the transformer at SCE's MacArthur substation. The SCX prime contractor is SuperPower Inc. (SPI), teamed with SPX Transformer Solutions (SPX) {formerly Waukesha Electric Systems}. SCE has provided two letters of commitment for SCX. The SCX project will develop a 28 MVA High Temperature Superconducting, Fault Current Limiting (HTS-FCL) transformer. The transformer is expected to be installed in 2015. SCE is supporting this project and is not an ARRA grant sub-recipient. SCE is being reimbursed for its effort by EPIC. SCE's participation in this project was previously approved under the now defunct California Energy Commission's PIER program.	8/15/2012	No	Distribution	$ -	$ 10,241	$ -	$ 10,241	$ 10,241	N/A
1st triennial (2012-2014)	SCE	**State Estimation Using Phasor Measurement Technologies**	Cross-Cutting/Foundational Strategies & Technologies	Accurate and timely power system state estimation data is essential for understanding system health and provides the basis for corrective action that could avoid failures and outages. This project will demonstrate the utility of improved static system state estimation using Phasor Measurement Unit (PMU) data in concert with existing systems. Enhancements to static state estimation will be investigated using two approaches: 1) by using GPS time to synchronize PMU data with Supervisory Control and Data Acquisition (SCADA) system data; 2) by augmenting SCE's existing conventional state estimator with a PMU based Linear State Estimator (LSE).	8/15/2012	No	Grid Operation/Market Design	$ 1,046,100	$ 823,781	$ 280,046	$ 516,528	$ 796,574	N/A
1st triennial (2012-2014)	SCE	**Wide-Area Reliability Management & Control**	Energy Resources Integration	With the planned wind and solar portfolio of 33% penetration, a review of the integration strategy implemented in the SCE bulk system is needed. The basic premise for the integration strategy is that a failure in one area of the grid should not result in failures elsewhere. The approach is to minimize failures with well designed, maintained, operated, and coordinated power grids. New technologies can provide coordinated wide-area monitoring, protection, and control systems with pattern recognition and advance warning capabilities. This project will demonstrate new technologies to manage transmission system control devices to prevent cascading outages and maintain system integrity.	8/15/2012	No	Grid Operation/Market Design	$ 927,510	$ 923,814	$ 318,286	$ 122,769	$ 441,055	N/A
1st triennial (2012-2014)	SCE	**Distributed Optimized Storage (DOS)**	Energy Resources Integration	This field pilot will demonstrate end-to-end integration of multiple energy storage devices on a distribution circuit/feeder to provide a turn-key solution that can cost-effectively be considered for SCE's distribution system, where identified feeders can benefit from grid optimization and variable energy resources (VER) integration. To accomplish this, the project team will first identify distribution system feeders where multiple energy storage devices can be operated centrally. Once a feeder is selected, the energy storage devices will be deployed and tested to demonstrate seamless utility integration, control, and operation of these devices using a single centralized controller. At the end of the project, SCE will have established clear methodologies for identifying feeders that can benefit from distributed energy storage devices and will have established necessary standards-based hardware and control function requirements for grid optimization and renewables integration with distributed energy storage devices.	8/15/2012	No	Distribution	$ -	$ 635,533	$ 540	$ 81,321	$ 81,861	N/A

Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total	Administrative and overhead costs incurred for each project
1st triennial (2012-2014)	SCE	**Outage Management and Customer Voltage Data Analytics Demonstration**	Customer Focused Products and Services	Voltage data and customer energy usage data from the Smart Meter network can be collected and leveraged for a range of initiatives focused on achieving operational benefits for Transmission & Distribution. Before a full implementation of this new approach can be considered, a Pilot project will be conducted to understand how voltage and consumption data can be best collected, stored, and integrated with T&D applications to provide analytics and visualization capabilities. Further, Smart Meter outage and restoration event (time stamp) data can be leveraged to improve customer outage duration and frequency calculations. Various stakeholders in T&D have identified business needs to pursue more effective and efficient ways of calculating SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index), and MAIFI (Momentary Average Interruption Frequency Index) for internal and external reporting. Before a full implementation of this new approach can be considered, a Pilot project will be conducted to understand the feasibility and value of providing smart meter data inputs and enhanced methodology for calculating the Indexes. The Pilot will focus on a limited geography (SCE District or Region) to obtain the Smart Meter inputs to calculate the Indexes and compare that number with the current methodologies to identify any anomalies. A hybrid approach using the Smart Meter-based input data combined with a better comprehensive electric connectivity model obtained from GIS may provide a more efficient and effective way of calculating the Indexes. Additionally, an effort to evaluate the accuracy of the Transformer Load Mapping data will be carried out.	11/1/2012	No	Grid Operation/Market Design	$ -	$ 1,020,421	$ 702,359	$ 318,062	$ 1,020,421	N/A
1st triennial (2012-2014)	SCE	**SA-3 Phase III Demonstration**	Grid Modernization and Optimization	This project is intended to apply the findings from the Substation Automation Three (SA-3) Phase II (Irvine Smart Grid Demonstration) project to demonstrate real solutions to automation problems faced by SCE today. The project will demonstrate two standards-based automation solutions (sub-projects) as follows: Subproject 1 (Bulk Electric System) will address issues unique to transmission substations including the integration of centrally managed critical cyber security (CCS) systems and NERC CIP compliance; Subproject 2 (Hybrid) will address the integration of SA 3 capabilities with SAS and SA-2 legacy systems. Furthermore, as part of the systems engineering the SA-3 technical team will demonstrate two automation tools as follows: Subproject 3 (Intelligent Alarming) will allow substation operators to pin-point root cause issues by analyzing the various scenarios and implement an intelligent alarming system that can identify the source of the problem and give operators only the relevant information needed to make informed decisions; and Subproject 4 (Real Time Digital Simulator (RTDS) Mobile Testing) will explore the benefits of an automated testing using a mobile RTDS unit, and propose test methodologies that can be implemented into the factory acceptance testing (FAT) and site acceptance testing (SAT) testing process.	8/15/2012	No	Transmission	$ 670,221	$ 3,995,462	$ 767,409	$ 700,551	$ 1,467,960	N/A
1st triennial (2012-2014)	SCE	**Next-Generation Distribution Automation**	Grid Modernization and Optimization	SCE's current distribution automation scheme often relies on human intervention that can take several minutes (or longer during storm conditions) to isolate faults, is only capable of automatically restoring power to half of the customers on the affected circuit, and needs to be replaced due to assets nearing the end of their lifecycle. In addition, the self-healing circuit being demonstrated as part of the Irvine Smart Grid Demonstration is unique to the two participating circuits and may not be easily applied elsewhere. As a result, the Next-Generation Distribution Automation project intends to demonstrate a cost-effective advanced automation solution that can be applied to the majority of SCE's distribution circuits. This solution will utilize automated switching devices combined with the latest protection and wireless communication technologies to enable detection and isolation of faults before the substation circuit breaker is opened, so that at least 2/3 of the circuit load can be restored quickly. This will improve reliability and reduce customer minutes of interruption. The system will also have directional power flow sensing to help SCE better manage distributed energy resources on the distribution system. At the end of the project, SCE will provide reports on the field demonstrations and recommend next steps for new standards for next-generation distribution automation.	8/15/2012	No	Distribution	$ 3,062,659	$ 4,360,028	$ 2,949,380	$ 1,225,649	$ 4,175,029	N/A

Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total	Administrative and overhead costs incurred for each project
1st triennial (2012-2014)	SCE	**Enhanced Infrastructure Technology Evaluation**	Grid Modernization and Optimization	At the request of Distribution Apparatus Engineering (DAE) group's lead Civil Engineer, Advanced Technology (AT) will investigate, pilot, and come up with recommendations for enhanced infrastructure technologies. The project will focus on evaluating advanced: distribution sectional poles (hybrid, coatings, etc.), concealed communications on assets, vault monitoring systems (temperature, water, etc.), and vault ventilation systems. Funding is required to investigate the problem, engineering, pilot alternatives, and come up with recommendations. DAE sees the need for poles that can withstand fires and have a better life cycle cost, and provide installation efficiencies when compared to existing wood pole replacements. Due to increased city restrictions, there is a need for more concealed communications on our assets such as streetlights (e.g., on the ISGD project, the City of Irvine wouldn't allow us to install repeaters on streetlights due to aesthetics). DAE also sees the need for technologies that may minimize premature vault change-outs (avg. replacement cost is ~$250K). At present, DAE does not have the necessary real-time vault data to sufficiently address the increasing vault deterioration issue nor do we utilize a hardened ventilation system that would help this issue by removing the excess heat out of the vaults (blowers last ~ 2 years, need better bearings for blower motors, etc.).	12/17/2013	No	Distribution	$ -	$ 79,119	$ 31,700	$ 47,419	$ 79,119	N/A
1st triennial (2012-2014)	SCE	**Dynamic Line Rating Demonstration**	Grid Modernization and Optimization	Transmission line owners apply fixed thermal rating limits for power transmission lines. These limits are based on conservative assumptions of wind speed, ambient temperature and solar radiation. They are established to ensure compliance with safety codes, maintain the integrity of line materials, and ensure network reliability. Monitored transmission lines can be more fully utilized to improve network efficiency. Line tension is directly related to average conductor temperature. The tension of a power line is directly related to the current rating of the line. This project will demonstrate the CAT-1 dynamic line rating solution. The CAT-1 system will monitor the tension of transmission lines in real-time to calculate a dynamic daily rating. If successful, this solution will allow SCE to perform real-time calculations in order to determine dynamic daily rating of transmission lines, thus increasing transmission line capacity.	12/17/2013	No	Transmission	$ -	$ 469,079	$ 386,155	$ 82,924	$ 469,079	N/A
1st triennial (2012-2014)	SCE	**Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)**	Cross-Cutting/Foundational Strategies & Technologies	Viasat in partnership with SCE and Duke Energy has been awarded a DOE contract (DE-0E0000675) to deploy a Cyber-intrusion Auto-response and Policy Management System (CAPMS) to provide real-time analysis of root cause, extent and consequence of an ongoing cyber intrusion using proactive security measures. CAPMS will be demonstrated in the SCE Advanced Technology labs at Westminster, CA. The DOE contract value is $6M with SCE & Duke Energy offering a cost share of $1.6M and $1.2M respectively.	7/16/2014	Yes	Grid Operation/Market Design	$ -	$ 1,809,323	$ 1,703,701	$ 105,622	$ 1,809,323	N/A
2nd triennial (2015-2017)	SCE	**Integration of Big Data for Advanced Automated Customer Load Management**	Customer Focused Products and Services	This proposed project builds upon the "Beyond the Meter Advanced Device Communications" project from the first EPIC triennial investment plan, and purposes to demonstrate how the concept of "big data" can be leveraged for automated load management. More specifically, this potential project would demonstrate the use of big data acquired from utility systems such as SCE's advanced metering infrastructure (AMI), distribution management system (DMS), and Advanced Load Control System (ALCS) to determine the optimal load management scheme and execute by communicating to centralized energy hubs at the customer level.	11/17/2014	Yes	Demand-Side Management	$ 92,160	$ 858,943	$ 75,181	$ 34,108	$ 109,289	$ 5,113

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2nd triennial (2015-2017)	SCE	**Advanced Grid Capabilities Using Smart Meter Data**	Grid Modernization and Optimization	This project will examine the possibility of establishing the Phasing information for distribution circuits, by examining the voltage signature at the meter and transformer level, and by leveraging the connectivity model of the circuits. This project will also examine the possibility of establishing transformer to meter connectivity based on the voltage signature at the meter and at the transformer level.	11/17/2014	Yes	Distribution	$ -	$ 350,920	$ 8,801	$ 271,061	$ 279,862	$ 6,871
2nd triennial (2015-2017)	SCE	**Proactive Storm Impact Analysis Demonstration**	Grid Modernization and Optimization	This project will demonstrate proactive storm analysis techniques prior to its arrival and estimate its potential impact on utility operations. In this project, we will investigate some technologies that can model a developing storm and its potential movement through the utility service territory based on weather projections. This information and model will then be integrated with the Geographic Information System (GIS) electrical connectivity model, Distribution Management System (DMS), and Outage Management System (OMS) functionalities, along with historical storm data to predict the potential impact on the service to customers. In addition, this project will demonstration the integration of near real time meter voltage data with the GIS network to develop a simulated circuit model that can be effectively utilized fo rstorm management an dfield crew deployment.	11/17/2014	Yes	Distribution	$ 1,198,480	$ 903,179	$ 450,484	$ 204,616	$ 655,100	$ 12,464
2nd triennial (2015-2017)	SCE	**Next-Generation Distribution Equipment & Automation - Phase 2**	Grid Modernization and Optimization	This project will leverage lessons learned from the Next Generation Distribution Automation – Phase 1 project performed in the first EPIC triennial investment plan period. This project will focus on integrating advanced control systems, modern wireless communication systems, and the latest breakthroughs in distribution equipment and sensing technology to develop a complete system design that would be a standard for distribution automation and advanced distribution equipment	11/16/2015	No	Distribution	$ 1,065,783	$ 5,918,110	$ 694,774	$ 445,480	$ 1,140,254	$ 30,067

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2nd triennial (2015-2017)	SCE	**System Intelligence and Situational Awareness Capabilities**	Grid Modernization and Optimization	This project will demonstrate system intelligence and situation awareness capabilities such as high impedance fault detection, intelligent alarming, predictive maintenance, and automated testing. This will be accomplished by integrating intelligent algorithms and advanced applications with the latest substation automation technologies, next generation control systems, latest breakthrough in substation equipment, sensing technology, and communications assisted protection schemes, This system will leverage the IEC 61850 Automation Standard and will include cost saving technology such as process bus, peer to peer communications, and automated engineering and testing technology. This project will also inform complementary efforts at SCE aimed at meeting security and NERC CIP compliance requirements	11/16/2015	No	Distribution	$ 1,665,835	$ 2,357,245	$ 463,911	$ 116,173	$ 580,084	$ 17,269
2nd triennial (2015-2017)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration - Phase 2**	Customer Focused Products and Services	This project expands on the submetering project from the first EPIC triennial investment plan cycle to demonstrate plug-in electric vehicle (PEV) submetering at multi-dwelling and commercial facilities. Specifically, the project will leverage 3rd party metering to conduct subtractive billing for various sites including those with multiple customers of record	11/17/2014	Yes	Demand-Side Management	$ -	$ 2,258,000	$ 296,975	$ 3,475	$ 300,450	$ 8,122

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2nd triennial (2015-2017)	SCE	**Bulk System Restoration Under High Renewables Penetration**	Renewables/DER Resource Integration	The Bulk System Restoration under High Renewable Penetration Project will evaluate system restoration plans following a blackout event under high penetration of wind and solar generation resources. Typically the entire restoration plan consists of three main stages; Black Start, System Stabilization, and load pick-up. The Project will be divided into two phases: * Phase I of the project will address the feasibility of new approaches to system restoration by reviewing the existing system restoration plans and it's suitability for higher penetration of renewable generation. It will include a suitable RTDS Bulk Power system to be used in the first stage of system restoration, black start and it will also include the modeling of wind and solar renewable resources. * Phase II of the project will focus on on-line evaluation of restoration plans using scenarios created using (RTDS) with hardware in the loop such as generation, transformer and transmission line protective relays. The RTDS is a well-known tool to assess and evaluate performance of protection and control equipment. This project intends to utilize the RTDS capabilities to evaluate and demonstrate system restoration strategies with variable renewable resources focusing on system stabilization and cold load pick-up. Furthermore alternate restoration scenarios will be investigated. After the restoration process is evaluated, tested, and demonstrated in the RTDS Lab environment, a recommendation will be provided to system operations and transmission planning for their inputs for further developing this approach into an actual operational tool.	11/17/2014	Yes	Transmission	$ -	$ 42,366	$ 7,500	$ 34,866	$ 42,366	$ 4,355
2nd triennial (2015-2017)	SCE	**Series Compensation for Load Flow Control**	Renewables/DER Resource Integration	The intent of this project is to demonstrate and deploy the use of Thyristor Controlled Series Capacitors (TCSC) for load flow control on series compensated transmission lines. On SCE's 500 kV system in particular, several long transmission lines are series compensated using fixed capacitor segments that do not support active control of power flow. The existing fixed series capacitors use solid state devices as a protection method and are called Thyristor Protected Series Capacitors (TPSC)	11/16/2015	No	Transmission	$ -	$ 9,593	$ -	$ 9,593	$ 9,593	$ 2,548
2nd triennial (2015-2017)	SCE	**Versatile Plug-in Auxiliary Power System (VAPS)**	Grid Modernization and Optimization	This project demonstrates the electrification of transportation and vocational loads that previously used internal combustion engines powered by petroleum fuels in the SCE fleet. The VAPS system uses automotive grade lithium ion battery technology (Chevrolet Volt and Ford Focus EV) which is also used in notable stationary energy storage projects (Tehachapi 32 MWh Storage)	11/17/2014	Yes	Distribution	$ 103,945	$ 1,429,225	$ 108,219	$ 119,254	$ 227,473	$ 5,638
2nd triennial (2015-2017)	SCE	**Dynamic Power Conditioner**	Grid Modernization and Optimization	This project will demonstrate the use of the latest advances in power electronics and energy storage devices and controls to provide dynamic phase balancing as well as providing voltage control, harmonics cancellation, sag mitigation, and power factor control while providing steady state operations such as injection and absorption of real and reactive power under scheduled duty cycles or external triggers. This project aims to mitigate the cause of high neutral currents and provide several power quality benefits through the use of actively controlled real and reactive power injection and absorption	11/17/2014	Yes	Distribution	$ -	$ 1,191,083	$ 1,275	$ 11,891	$ 13,166	$ 1,197

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2nd triennial (2015-2017)	SCE	**Optimized Control of Multiple Storage Systems**	Renewables/DER Resource Integration	This project aims to demonstrate the ability of multiple energy storage controllers to integrate with SCE's Distribution Management System (DMS) and other decision making engines to realize optimum dispatch of real and reactive power based on grid needs	11/17/2014	Yes	Distribution	$ -	$ 362,565	$ -	$ 2,565	$ 2,565	$ -
2nd triennial (2015-2017)	SCE	**DC Fast Charging Demonstration**	Customer Focused Products and Services	The goal of this project is to demonstrate public DC fast charging stations at SCE facilities near freeways in optimal locations to benefit electric vehicle miles traveled (eVMT) by plug-in electric vehicles (PEVs) while implementing smart grid equipment and techniques to minimize system impact. The Transportation Electrification (TE) Organization is actively pursuing several strategic objectives, including optimizing TE fueling from the grid to improve asset utilization. Deploying a limited number of fast charging stations at selected SCE facilities that are already equipped to deliver power at this level (without additional infrastructure upgrade) will support this objective. The project will leverage SCE's vast service territory and its facilities to help PEV reach destinations that would otherwise be out-of-range	11/16/2015	No	Demand-Side Management	$ -	$ 39,890	$ -	$ 10,870	$ 10,870	$ 1,172
2nd triennial (2015-2017)	SCE	**Integrated Grid Project II**	Cross-Cutting/Foundational Strategies & Technologies	The project will deploy, field test and measure innovative technologies that emerge from the design phase of the Integrated Grid Project (IGP) that address the impacts of DER (Distributed Energy Resources) owned by both 3rd parties and the utility. The objectives are to demonstrate the next generation grid infrastructure that manages, operates, and optimizes the distributed energy resources on SCE's system. The results will help determine the controls and protocols needed to manage DER, how to optimally manage an integrated distribution system to provide safe, reliable, affordable service and also how to validate locational value of DERs and understand impacts to future utility investments.	4/21/2016	No	Grid Operation/Market Design	$ 7,274,568	$ 17,614,570	$ 1,571,680	$ 67,056	$ 1,638,736	$ -

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1st triennial (2012-2014)	SCE	**Integrated Grid Project** *Note: Previously referred to as Regional Grid Optimization*	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid (Request for Proposals): Enbala Power Networks; Integral Analytics, LLC; Directed Awards Issued to the Following Vendor(s): Corepoint 1, Inc; Pacific Coast Engineering; Optiv Security, Inc; Ramsey Electronics:	9	Integral Analytics Enbala	1st 2nd	Does not apply; Highest scoring bidders were selected for award.
1st triennial (2012-2014)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration**	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	This was a “quasi-competitive” bid process conducted by the Energy Division (ED) of the CPUC	The ED opened the Phase 1 Pilot Submetering MDMA participation to all companies. Four companies applied: Electric Motor Werks, KnGrid, NRG and Ohmconnect. All four passed the initial pass/fail ED screening.	All four companies were approved by the ED to participate in the Phase 1 Submetering Pilot. Electric Motor Werks, KnGrid, NRG and Ohmconnect	There was no ranking provided by the ED. The four companies were free to choose which of the three IOU territories it wanted to participate in. Three companies, Electric Motor Werks, NRG and Ohmconnect selected to participate in SCE's territory. Note: PO process is not yet complete for Electric Motor Werks.	ED did not provide any scoring of the applicants.
1st triennial (2012-2014)	SCE	**Distribution Planning Tool**	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Battelle Memorial Institute CYME International T&D Inc. INFOSYS Limited Nexant Inc Siemenes Industry Siements Indsustry, Inc.	N/A	N/A	N/A	N/A

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1st triennial (2012-2014)	SCE	**Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)**	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid (Request for Proposals) & Directed Awards Directed Awards Issued to the Following Vendor(s): Autogrid Systems, Inc.; Qualitylogic, Inc.	2	Saker Systems, LLC	1	Does not apply; Highest scoring bidder was selected for award.
1st triennial (2012-2014)	SCE	**Portable End-to-End Test System**	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Doble Engineering Company; General Electric Company: RTDS Technologies Inc.; Schweitzer Engineering Labs Inc.	N/A	N/A	N/A	N/A
1st triennial (2012-2014)	SCE	**Voltage and VAR Control of SCE Transmission System**	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Siemens Industry, Inc; The Mathworks, Inc Nexant Inc	TBD	TBD	TBD	TBD

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1st triennial (2012-2014)	SCE	**Superconducting Transformer (SCX) Demo**	N/A	SuperPower Inc.; SPX Transformer Solutions	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	N/A	N/A	N/A	N/A	N/A
1st triennial (2012-2014)	SCE	**State Estimation Using Phasor Measurement Technologies**	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Power World Corporation Electric Power Group, LLC	TBD	TBD	TBD	TBD
1st triennial (2012-2014)	SCE	**Wide-Area Reliability Management & Control**	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): V&R Energy Systems Research, Inc.; Siemens Industry, Inc	N/A	N/A	N/A	N/A
1st triennial (2012-2014)	SCE	**Distributed Optimized Storage (DOS)**	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD

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1st triennial (2012-2014)	SCE	**Outage Management and Customer Voltage Data Analytics Demonstration**	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Cyient, Inc.; Nexant Inc	N/A	N/A	N/A	N/A
1st triennial (2012-2014)	SCE	**SA-3 Phase III Demonstration**	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid ((Request for Proposal) to the Following Vendor(s): 1- Everest Technical (Direct award) to the Following Vendor(s): 2- DC Systems	Procurement #1:4	Procurement #1: Everest Technical	Procurement #1: 1	N/A
1st triennial (2012-2014)	SCE	**Next-Generation Distribution Automation**	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid Directed Awards Issued to the Following Vendor(s): Cleaveland Price Inc.; Doble Engineering Company; GE MDS LLC.; One Source Supply Solutions LLC.	2	G&W Electric Company; Par Electrical Contractors Inc.	G&W Electric Company; Par Electrical Contractors Inc.	

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1st triennial (2012-2014)	SCE	**Enhanced Infrastructure Technology Evaluation**	N/A	N/A	N/A	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): American Restore, Inc.; Rivcomm, Inc.; California Turbo Inc	N/A	N/A	N/A	N/A
1st triennial (2012-2014)	SCE	**Dynamic Line Rating Demonstration**	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Wesco Distribution Inc Black & Veatch Corporation The Valley Group	N/A	N/A	N/A	N/A
1st triennial (2012-2014)	SCE	**Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)**	DOE & Duke Energy Contributions: $4,486,430	Viasat; Duke Energy	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): @ Business Inc; Magnetic Instrumentation Inc; Saker Systems, LLC; World Wide Technology Inc; Zones, Inc.; Accuvant Inc; Electric Power Group, LLC; Schweitzer Engineering Labs Inc	N/A	N/A	N/A	N/A
2nd triennial (2015-2017)	SCE	**Integration of Big Data for Advanced Automated Customer Load Management**	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive	1	Kitu, Inc	TBD	TBD

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2nd triennial (2015-2017)	SCE	**Advanced Grid Capabilities Using Smart Meter Data**	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	None - no awards granted	N/A	N/A	N/A	N/A
2nd triennial (2015-2017)	SCE	**Proactive Storm Impact Analysis Demonstration**	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive	9	IBM, First Quartile Consulting	TBD	TBD
2nd triennial (2015-2017)	SCE	**Next-Generation Distribution Equipment & Automation - Phase 2**	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid Directed Awards Issued to the Following Vendor(s): Athena Power, Inc.; G&W Electric Company; Southwest Research Institute	4	Cleaveland Price Inc.; Schneider Electric; Sentient Energy, Inc.; Wesco Distribution Inc.	Cleaveland Price Inc.; Schneider Electric; Sentient Energy, Inc.; Wesco Distribution Inc.	Multiple prototypes were required for testing purposes

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2nd triennial (2015-2017)	SCE	**System Intelligence and Situational Awareness Capabilities**	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid Directed Awards Issued to the Following Vendor(s): GENERAL NETWORKS, TESCO AUTOMATION LTD, MORRIS & WILLNER PARTNERS,	TBD	TBD	TBD	TBD
2nd triennial (2015-2017)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration - Phase 2**	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD

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2nd triennial (2015-2017)	SCE	**Bulk System Restoration Under High Renewables Penetration**	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Non-Competitive Nayak Corporation Inc	NA	NA	NA	NA
2nd triennial (2015-2017)	SCE	**Series Compensation for Load Flow Control**	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD
2nd triennial (2015-2017)	SCE	**Versatile Plug-in Auxiliary Power System (VAPS)**	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid Directed Awards Issued to the Following Vendor(s): FleetCarma	1	Altec Industries Inc.	1	N/A
2nd triennial (2015-2017)	SCE	**Dynamic Power Conditioner**	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD

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2nd triennial (2015-2017)	SCE	**Optimized Control of Multiple Storage Systems**	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD
2nd triennial (2015-2017)	SCE	**DC Fast Charging Demonstration**	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD
2nd triennial (2015-2017)	SCE	**Integrated Grid Project II**	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid (Request for Proposals): Enbala Power Networks; Integral Analytics, LLC; Directed Awards Issued to the Following Vendor(s): DigSilent Americas LLC: Morris & Willner Partners; GE Management Services, LLC; World Wide Technology, Inc; Zones, Inc	9	Integral Analytics Enbala	1st 2nd	Does not apply; Highest scoring bidders were selected for award.

Investment Program Period	Program Administrator	Project Name	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy	Applicable metrics
1st triennial (2012-2014)	SCE	**Integrated Grid Project** *Note: Previously referred to as Regional Grid Optimization*	N/A; Applicable to CEC only.	@ Business, Inc.: California-based entity Bridgewater Consulting Group, Inc: California-based entity; Small Business; DBE Corepoint 1, Inc: California-based entity Pacific Coast Engineering: California-based entity; Small Business	N/A; Applicable to CEC only.	1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 1h. Customer bill savings (dollars saved) 1i. Nameplate capacity (MW) of grid-connected energy storage 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5a. Outage number, frequency and duration reductions 5b. Electric system power flow congestion reduction 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and
1st triennial (2012-2014)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration**	N/A; Applicable to CEC only.	NRG: N/A Ohmconnect: California-based entity Electric Motor Werks: California-based entity	N/A; Applicable to CEC only.	6a. TOTAL number of SCE customer participants (Phase 1 & 2 each have 500 submeter limit) 6b. Number of SCE NEM customer participants (Phase 1 & 2 each have 100 submeter limit of 500 total) 6c. Submeter MDMA on-time delivery of customer submeter interval usage data 6d. Submeter MDMA accuracy of customer submeter interval usage data
1st triennial (2012-2014)	SCE	**Distribution Planning Tool**	N/A; Applicable to CEC only.	Battelle Memorial Institute: N/A CYME International T&D Inc. - N/A INFOSYS Limited - Yes (CA entitiy) Nexant Inc - Yes (CA entitiy) Siemenes Industry - Yes (CA entitiy) Siements Indsustry, Inc. - Yes (CA entitiy)	N/A; Applicable to CEC only.	1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 5c. Forecast accuracy improvement 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360); 8c. Number of times reports are cited in scientific journals and trade publications for selected projects. 8d. Number of information sharing forums held. 8f. Technology transfer 9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market).

Investment Program Period	Program Administrator	Project Name	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy	Applicable metrics
1st triennial (2012-2014)	SCE	**Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)**	N/A; Applicable to CEC only.	Saker Systems LLC: California-base entity; DBE Autogrid Systems, Inc: California-base entity Qualitylogic, Inc.: California-base entity	N/A; Applicable to CEC only.	1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5b. Electric system power flow congestion reduction 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360); 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360); 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360); 7g. Integration of cost-effective smart appliances and consumer devices (PU Code § 8360); 7h. Deployment and integration of cost-effective advanced electricity storage and
1st triennial (2012-2014)	SCE	**Portable End-to-End Test System**	N/A; Applicable to CEC only.	Doble Engineering Company: N/A General Electric Company: N/A RTDS Technologies Inc.: N/A Schweitzer Engineering Labs Inc: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 5a. Outage number, frequency and duration reductions 6a. Reduction in testing cost 6b. Number of terminals tested on a line (more than 2 terminals/substations) 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9e. Technologies available for sale in the market place (when known).
1st triennial (2012-2014)	SCE	**Voltage and VAR Control of SCE Transmission System**	N/A; Applicable to CEC only.	Siemens Industry, Inc: California-based entity The Mathworks, Inc: N/A Nextant Inc - California- based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market).

Investment Program Period	Program Administrator	Project Name	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy	Applicable metrics
1st triennial (2012-2014)	SCE	**Superconducting Transformer (SCX) Demo**	N/A; Applicable to CEC only.	N/A; Project is cancelled.	N/A; Applicable to CEC only.	N/A; Project is cancelled
1st triennial (2012-2014)	SCE	**State Estimation Using Phasor Measurement Technologies**	N/A; Applicable to CEC only.	Power World Corporation: California-based entity Electric Power Group, LLC: Callifornia-based entity; Small Business; MBE	N/A; Applicable to CEC only.	6a. Enhanced grid monitoring and on-line analysis for resiliency 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9d. Successful project outcomes ready for use in California IOU grid (Path to market). 9e. Technologies available for sale in the market place (when known).
1st triennial (2012-2014)	SCE	**Wide-Area Reliability Management & Control**	N/A; Applicable to CEC only.	V&R Energy Systems Research, Inc.: California-based entity Siemens Industry, Inc.: California-based entity	N/A; Applicable to CEC only.	6a. Enhanced contingency planning for minimizing cascading outages 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer
1st triennial (2012-2014)	SCE	**Distributed Optimized Storage (DOS)**	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	1c. Avoided procurement and generation costs 1i. Nameplate capacity (MW) of grid-connected energy storage 3b. Maintain / Reduce capital costs 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 6a. Benefits in energy storage sizing through device operation optimization 6b. Benefits in distributed energy storage deployment vs. centralized energy storage deployment 7a. Description of the issues, project(s), and the results or outcomes 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports.

Investment Program Period	Program Administrator	Project Name	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy	Applicable metrics
1st triennial (2012-2014)	SCE	**Outage Management and Customer Voltage Data Analytics Demonstration**	N/A; Applicable to CEC only.	Cyient, Inc.: N/A Nexant Inc: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 6a. Enhance Outage Reporting Accurary and SAIDI/SAIFI Calculation 8b. Number of reports and fact sheets published online 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports.
1st triennial (2012-2014)	SCE	**SA-3 Phase III Demonstration**	N/A; Applicable to CEC only.	Everest Technical: California-based entity DCSystems: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 5a. Outage number, frequency and duration reductions 5i. Increase in the number of nodes in the power system at monitoring points 6a. Increased cybersecurity 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market). 9e. Technologies available for sale in the market place (when known).
1st triennial (2012-2014)	SCE	**Next-Generation Distribution Automation**	N/A; Applicable to CEC only.	G&W Electric Company: California-based entity; Small Business Par Electrical Contractors Inc.: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 5i. Increase in the number of nodes in the power system at monitoring points 6a. Improve data accuracy for distribution substation planning process 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360);

Investment Program Period	Program Administrator	Project Name	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy	Applicable metrics
1st triennial (2012-2014)	SCE	**Enhanced Infrastructure Technology Evaluation**	N/A; Applicable to CEC only.	American Restore, Inc.: California-based entity Rivcomm, Inc.: California-based entity; Small Business California Turbo Inc: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 4g. Wildlife fatality reductions (electrocutions, collisions) 5a. Outage number, frequency and duration reductions 6a. Operating performance of underground vault monitoring equipment 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports.
1st triennial (2012-2014)	SCE	**Dynamic Line Rating Demonstration**	N/A; Applicable to CEC only.	Wesco Distribution Inc: California-based entity; DBE Black & Veatch Corporation: California-based entity The Valley Group - N/A	N/A; Applicable to CEC only.	3b. Maintain / Reduce capital costs 5b. Electric system power flow congestion reduction 6a. Increased power flow throughput 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market). 9e. Technologies available for sale in the market place (when known).
1st triennial (2012-2014)	SCE	**Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)**	N/A; Applicable to CEC only.	@ Business Inc: DBE Magnetic Instrumentation Inc: N/A Saker Systems, LLC: California-base entity; Small Business; DBE World Wide Technology Inc: DBE Zones, Inc.: DBE Accuvant Inc: California-based entity Electric Power Group, LLC: California-based entity Schweitzer Engineering Labs Inc: California-based entity	N/A; Applicable to CEC only.	5a. Outage number, frequency and duration reductions 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 10a. Description or documentation of funding or contributions committed by others 10c. Dollar value of funding or contributions committed by others.
2nd triennial (2015-2017)	SCE	**Integration of Big Data for Advanced Automated Customer Load Management**	N/A; Applicable to CEC only.	Small Business	N/A; Applicable to CEC only.	Metrics plan TBD

Investment Program Period	Program Administrator	Project Name	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy	Applicable metrics
2nd triennial (2015-2017)	SCE	**Advanced Grid Capabilities Using Smart Meter Data**	N/A; Applicable to CEC only.	N/A	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 8d. Number of information sharing forums held 8f. Technology transfer
2nd triennial (2015-2017)	SCE	**Proactive Storm Impact Analysis Demonstration**	N/A; Applicable to CEC only.	First Quartile: Small Business	N/A; Applicable to CEC only.	2a. Hours worked in California and money spent in California for each project 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 8f. Technology transfer 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
2nd triennial (2015-2017)	SCE	**Next-Generation Distribution Equipment & Automation - Phase 2**	N/A; Applicable to CEC only.	Sentient Energy, Inc.: California-based entity Wesco Distribution Inc.: California-based entity; Business owned by women, minorities, or disabled veterans	N/A; Applicable to CEC only.	Metrics plan TBD

Investment Program Period	Program Administrator	Project Name	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy	Applicable metrics
2nd triennial (2015-2017)	SCE	**System Intelligence and Situational Awareness Capabilities**	N/A; Applicable to CEC only.	GENERAL NETWORKS: California-based entity MORRIS & WILLNER PARTNERS: California-based entity	N/A; Applicable to CEC only.	2a. Hours worked in California and money spent in California for each project 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5a. Outage number, frequency and duration reductions 5e. Utility worker safety improvement and hazard exposure reduction 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 8e. Stakeholders attendance at workshops 8f. Technology transfer
2nd triennial (2015-2017)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration - Phase 2**	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1h. Customer bill savings (dollars saved) 3e. Non-energy economic benefits 4a. GHG emissions reductions (MMTCO2e) 6a. The 3rd Party Evaluator, Nexant, in collaboration with the Energy Division and IOUs, will develop a set of metrics for Phase 2 to be included in the final report. 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 7j. Provide consumers with timely information and control options (PU Code § 8360): 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8e. Stakeholders attendance at workshops 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)

Investment Program Period	Program Administrator	Project Name	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy	Applicable metrics
2nd triennial (2015-2017)	SCE	**Bulk System Restoration Under High Renewables Penetration**	N/A; Applicable to CEC only.	Nayak Corporation - NA	N/A; Applicable to CEC only.	Metrics plan TBD
2nd triennial (2015-2017)	SCE	**Series Compensation for Load Flow Control**	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD
2nd triennial (2015-2017)	SCE	**Versatile Plug-in Auxiliary Power System (VAPS)**	N/A; Applicable to CEC only.	No	N/A; Applicable to CEC only.	Metrics plan TBD
2nd triennial (2015-2017)	SCE	**Dynamic Power Conditioner**	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD

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2nd triennial (2015-2017)	SCE	**Optimized Control of Multiple Storage Systems**	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD
2nd triennial (2015-2017)	SCE	**DC Fast Charging Demonstration**	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD
2nd triennial (2015-2017)	SCE	**Integrated Grid Project II**	N/A; Applicable to CEC only.	Morris & Willner Partners: Business owned my women, minorities or disabled veterans. World Wide Technology, Inc: Business owned my women, minorities or disabled veterans. Zones, Inc: Business owned my women, minorities or disabled veterans.	N/A; Applicable to CEC only.	1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 1h. Customer bill savings (dollars saved) 1i. Nameplate capacity (MW) of grid-connected energy storage 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5a. Outage number, frequency and duration reductions 5b. Electric system power flow congestion reduction 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and

Investment Program Period	Program Administrator	Project Name	Update	Coordination with CPUC Proceedings or Legislation
1st triennial (2012-2014)	SCE	**Integrated Grid Project** *Note: Previously referred to as Regional Grid Optimization*	In 2016, the Integrated Grid Project (IGP) project team finalized the execution scope, lab testing requirements, and field demonstration approach. The team also completed the architectural and system design of the project. The project team adopted two additional IGP scope elements: 1) Utilize energy storage as both a reliability and a market device, and 2) Develop a design for a secure interface between IGP systems and 3rd party aggregators for the control and monitoring of DERs. The project team built out and equipped the Advanced Technology (AT) labs, while also started the testing of the control systems, the Field Area Network (FAN), and the integration systems that are at the core of the IGP project. The following EPIC I activities were completed by the project team in 2016: • Focused project efforts on circuits out of Camden substation and Titanium circuit • Continued to work with site-location owners and SCE legal to secure monitoring and control of 3rd party DER resources • Obtained internal approvals from the Distribution Standards and Substation Standards committees to allow for timely installation of field equipment • Completed the system and design level project documentation, such as the System Design Document (SDD) and System Requirements Document (SRD) • Tested and down selected the FAN vendors • Selected battery energy storage system specifications and site to support IGP project requirements • Conducted collaborative working sessions, known as "Sprints", between SCE, the control vendors and the integration bus vendor to develop integration adapters • Finalized the testing environments and developed lab test plans and procedures for Factory Acceptance Testing (FAT) and Site Acceptance Testing (SAT)	Distribution Resources Plan, R.14-08-013; A.15-07-003 Integrated Demand-side Resource Program, R.14-10-003
1st triennial (2012-2014)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration**	The project is in the final closeout stage and the final report has been completed. The project team presented the results from the project to the stakeholders in January 2017, and is currently undergoing the closeout process. The project is under budget, and has been completed timely. Milestones achieved: • Requested and received CPUC's approval to extend the Phase 1 Pilot enrollment period six months. • Submitted Tier 1 Advice Letter to CPUC to update Phase 1 Pilot tariff due to Pilot extension. • Enrolled 92 SCE customers in the Pilot by end of extended enrollment period August 31, 2015. • Supporting 92 customers during their 12 month participation in the Phase 1 Pilot.	
1st triennial (2012-2014)	SCE	**Distribution Planning Tool**	In 2016 the project demonstrated a fully dynamic analysis to determine the DER hosting capacity at individual nodes within two distinct areas that represent the wide variety of distribution systems within SCE's service territory. The project examined the hosting capacity based on limiting categories of thermal rating, power quality and voltage criteria including steady state voltage and voltage fluctuation, protection coordination requirements, safety and reliability, as well as substation limitations. The project employed two different methodologies to calculate the DER hosting capacities under various scenarios such as with/without reverse power flow at distribution substation bus and various loading conditions throughout the year. The Streamlined Method performs one power flow simulation for each scenario and then extracts necessary quantities and use equations to determine the hosting capacities for each of the limiting categories. The Iterative Method utilizes iterative power flow simulations to determine the hosting capacities for each of the limiting categories. The hosting capacity results were published on SCE's Distributed Energy Resource Interconnection Map (DERiM) to share with the public.	Distribution Resources Plan, R.14-08-013; A.15-07-003

Investment Program Period	Program Administrator	Project Name	Update	Coordination with CPUC Proceedings or Legislation
1st triennial (2012-2014)	SCE	**Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)**	During 2016, the project team engaged internal and stakeholder groups including Grid Modernization, Sunspec Alliance, and the Smart Inverter Working Group in order to understand and document lower-level requirements and use cases critical to SCE, including regulatory requirements (Rule 21) related to the interconnection of BTM DERs. The technical team used the input to complete a Request for Information that resulted in a pool of candidate vendors and a Request for Proposal to be released in early 2017.	
1st triennial (2012-2014)	SCE	**Portable End-to-End Test System**	The test setup yielded lessons learned that pointed the team to determining that this technology was not a viable option at this time. For example, the test set up required significant power to drive 5 Doble test sets, as well as an outdoor area to set up a GPS antenna. Additionally the test setup needed to mirror field conditions (i.e., no external monitors, all test equipment needed to be transportable, etc.), so that we would be able to perform the test in a remote location without any unexpected events. Furthermore, the setup required a mobile RTDS unit and Doble test set per terminal, meaning that 3 of each (RTDS unit and Doble test set) would be needed for lines that contained 3 terminals. The team's analysis discovered however, that in our system very few 220 lines in fact have more than 2 terminals, and that the existing test systems were adequate options for testing 2 terminal lines. The objective of the PETS project was to meet EPIC's primary principle criteria of providing greater reliability to the customers. However, it was determined that the benefits associated with this demonstration project did not outweigh the costs and ultimately it would not provide added value. The project was successful in proving that the tools exist to conduct advanced end-to-end relay testing, albeit not cost effective.	
1st triennial (2012-2014)	SCE	**Voltage and VAR Control of SCE Transmission System**	The project was re-scoped and re-baselined earlier in 2016 to better align with company goals and stakeholder needs. The current project scope includes development, customization, and implementation of a voltage and VAr management tool that optimizes the voltage of the transmission and sub-transmission systems by optimizing the control over discrete reactive power resources. An offline study was conducted to quantify the benefits and estimate dollar savings of optimizing voltage profile to minimize active and reactive power losses on the transmission grid. In addition, to gather business and system requirements needed for the development of the tool, interviews with system operators (at the substation level) were conducted to understand how voltage and VAr management is performed locally. Bi-weekly stakeholder meetings were conducted to gather requirements from multiple stakeholder groups.	

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1st triennial (2012-2014)	SCE	**Superconducting Transformer (SCX) Demo**	SPX Transformer Solutions officially withdrew support from the project in Q2, 2014. As a result, SuperPower could no longer complete the delivery of the HTS-FCL transformer to SCE. SuperPower communicated the desire to identify a new transformer manufacturer as a partner, but was unable to secure one within a reasonable timeframe. At the time of SPX's withdrawal, SCE did not have an executed agreement with SuperPower. SCE formally cancelled this project in Q3 2014.	N/A - Cancelled.
1st triennial (2012-2014)	SCE	**State Estimation Using Phasor Measurement Technologies**	In 2016, SCE worked with EPG on the State Estimation using PMU to pilot the enhanced Linear State Estimator (eLSE) at Grid Control Center to perform data validation and conditioning on the synchrophasor stream and generate an estimate of phasors of nearby stations at same synchrophasor rate to increase systems observability. In addition, as part of this project, RTDMS (Real-Time Dynamics Monitoring System) was deployed to provide Grid Control Center with an advanced analytics and visualization system in order to better extract information from synchrophasor data to be used in real-time. The team collaborated and worked on the deployment of the GCC RTDMS/eLSE that included: 1. RTDMS Deployment at GCC for the Pilot Project including commissioning of RTDMS. 2. eLSE deployment, integration and implementation at GCC for expanding observability and data quality. 3. Developed and documented detailed procedures on how to modify and augment LSE to accommodate the future expansion of the SCE PMU infrastructure. 4. EPG and SCE provided 6 operator training sessions to over 22 SCE dispatchers/PSC Employees. The pilot implementation has been migrated to the production system after the team finished Site-Acceptance-Testing (SAT) at the Quality Assurance System (QAS) at Grid Control Center (GCC). The team developed and documented	
1st triennial (2012-2014)	SCE	**Wide-Area Reliability Management & Control**	In 2016, SCE has worked with Siemens on utilizing the Devers control system to increase the bulk system resilience. The project team implemented some initial test using a newly developed Devers SVC model into WECC case and test the response under different system contingencies. The next steps is for the team to finalize Devers SVC control system parameters tuning and implementing the updates to Devers SVC control system.	
1st triennial (2012-2014)	SCE	**Distributed Optimized Storage (DOS)**	During 2016, the DOS project continued to work with the Integrated Grid Project and the SCE's Energy Storage Ownership Initiative (ESOI). The team conducted multiple work shops to develop Use Cases, including the Dual Use capability. The team also developed draft functioal and non-functional requirements.	Energy Storage R,.15-03-011; D.14-10-040 & D.14-10-045 Resource Adequacy OIR, R.14-10-010

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1st triennial (2012-2014)	SCE	**Outage Management and Customer Voltage Data Analytics Demonstration**	The project demonstrated an analytics and visualization application that used smart meter data for distribution grid operational benefits. The project also conducted a feasibility study to determine if the use of smart meter data could improve the Outage Management SAIDI/SAIFI/MAIFI (reliability) metric calculation process. The following project milestones were achieved: i. The application was demonstrated in a lab environment using smart meter data of approximately 20,000 customers on 14 distribution circuits. ii. The application demonstrated 13 use cases developed by SCE using customer meter voltage, consumption and event data. iii. The application successfully overlaid the meter data on SCE's distribution system GIS to provide a visualization of the condition of the network. iv. The application was successfully tested by electric distribution planners and engineers. v. The feasibility study for using smart meter data in the calculation of system reliability indices was completed and several manually-intensive steps were identified for elimination. The project was successfully completed in 2015 and the final report will be submitted in 2016.	
1st triennial (2012-2014)	SCE	**SA-3 Phase III Demonstration**	The 2015 decision to reduce the SA-3 Phase III EPIC I budget from $10.4M to $4.1M resulted in stakeholder discussions which have now concluded, focusing the project on demonstrating SA-3 Bulk station capabilities. To accomplish the required budget reduction: 1- SA-3 Hybrid scope has been completely dropped from the SA-3 phase III demonstration. 2- SA-3 intelligent Alarming has been completely dropped from SA-3 phase III demonstration and moved to the System intelligence and Situational Awareness project under EPIC II funding 3- SA-3 real Time Simulator (RTDS) Mobile Testing has been completely dropped from SA-3 phase III demonstration and moved to the System intelligence and Situational Awareness project under EPIC II funding 4- The field portion of the SA-3 Bulk station demonstration has been completely dropped from SA-3 phase III demonstration and planned to move to EPIC III funding. 5- The SA-3 Bulk station Lab demonstration schedule has been extended to December 31, 2017 as a result of protracted discussions with stakeholders. 2016 Milestone Achieved: • Substation Engineering contractor selection complete • Engineering design SOW has been finalized and it has issued for bid • Engineering Design contractor RFP vendor selection has been completed • Engineering Design contractor purchase order has issued and Engineering design has started • SA-3 Data Concentrator Service RFP has been issued • The Engineering preliminary standards has created and sent out to the engineering contractor • The HMI Request for Budgetary proposal has been issued • Engineering contractor completed the design and the Engineering design is on Stake-holder review • HMI Service procurement has been completed • Substation Management System RFP has been issued	
1st triennial (2012-2014)	SCE	**Next-Generation Distribution Automation**	**Remote Intelligent Switch (RIS)** Following activities were accomplished during 2016 calendar year: • Enhanced system logic to accommodate expanded system requirements and behavior characteristics; • Further enhance hardware design resulting in two additional prototype designs; • Successfully accomplished Factory Acceptance Testing (FAT) and Site Acceptance Testing (SAT) activities; • Demonstrated 2.5 scheme at EDEF demonstration facility; and, • Successfully commissioned pilot (2.5 scheme) on the Poke and Bingo circuits. **High Impedance Fault Detection** Existing high impedance fault detection solutions available in the market focus on current and voltage monitoring; however, evaluation results demonstrate none of these technologies have been able to securely detect high impedance faults reliably (too many false alarms). As a result, a new approach is necessary and SCE's Advanced Technology considers the reflectometry-based solution as an innovative and promising approach. Advanced Technology and Apparatus Engineering are working with Southwest Research Institute (SWRI) to demonstrate the feasibility of implementing a reflectometry-based solution for detection of high impedance faults. **Long Beach Network Situation Awareness**	

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1st triennial (2012-2014)	SCE	**Enhanced Infrastructure Technology Evaluation**	In 2015, the project team accomplished the following: • Enhanced vault ventilation blower was specified, delivered, and is currently being field tested. • Developed draft specification for Hybrid Distribution Pole • Created conceptual insulator-antenna for initial communication testing • Installed vault temperature equipment for testing and monitoring In 2016, the project team accomplished the following: * Enhanced vault ventilation blower's field test was completed and recommendations were provided to SCE's Distribution Apparatus Engineering group	
1st triennial (2012-2014)	SCE	**Dynamic Line Rating Demonstration**	Although the project was cancelled before construction to install the equipment started, some initial studies were conducted. The main study that was conducted was a Path line-of-site survey that is essential to the success of communication. Poles M3-P4, M3-P7 and M4-P2 we surveyed for line-of-site with the antenna mounted on the transmission tower at Barre substation. It was determined that all three paths are obstructed by vegetation, which could potentially introduce interference in communication. In early 2016, a decision was made not to continue the work after the vendor decided not to support Dynamic Line Rating after the end of the demonstration phase. SCE closed this project out in 2016.	
1st triennial (2012-2014)	SCE	**Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)**		California Energy Solutions for the 21st Century (CES-21), D.14-03-029
2nd triennial (2015-2017)	SCE	**Integration of Big Data for Advanced Automated Customer Load Management**	In early 2016, a decision was made not to continue the work after the vendor decided not to support Dynamic Line Rating after the end of the demonstration phase. SCE closed this project out in 2016.	

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2nd triennial (2015-2017)	SCE	**Advanced Grid Capabilities Using Smart Meter Data**	Improving accuracy of Transformer/Meter correlation model: The project demonstrated a statistical model that correlates the voltage signature of a meter with that of other meters connected to the transformer to identify mismatches and provide a “better match” alternative. It also demonstrated an algorithm that improved accuracy by comparing the time period of single transformer outages to smart meter outage events to identify incorrectly mapped meters. The following activities were completed in 2015: i. Demonstration of Voltage signature and single transformer Outage events algorithms in a lab environment using smart meter data of 3 distribution circuits. ii. Identified data challenges and limitations on the use of the algorithms. iii. Completed validation of algorithms’ results through comparisons with field verified data. Phase identification of customers: It will demonstrate the algorithm developed in collaborative research by EPRI and SCE to identify the phase of a customer using SCADA, electrical network information and smart meter data. Additionally, the collaborative research by UC Riverside and SCE will be demonstrated in the later part of the project. i. Work on this subpart has been scheduled to start in 2016.	
2nd triennial (2015-2017)	SCE	**Proactive Storm Impact Analysis Demonstration**	In 2016 the project team demonstrated storm impact prediction models for all regions in SCE territory, at the district level, and across all asset types, including transformers, poles, and spans of wire, overhead and underground. Additionally, the team completed two user test sessions, for versions 1 and 2, respectively, with stakeholder users throughout SCE including Grid Operations, IT, Business Resiliency, and Field Services. The user test sessions served to provide key requirements for model versions 1 and 2. The team is scheduled to validate models in 2017 in a Hadoop cloud based platform to ensure production readiness by 2018.	Distribution Resources Plan, R.14-08-013; A.15-07-003 Integrated Demand-side Resource Program, R.14-10-003
2nd triennial (2015-2017)	SCE	**Next-Generation Distribution Equipment & Automation - Phase 2**	**LB Monitoring Network** • System Requirement Document drafted and completed. • Currently undergoing RFP process as additional information was requested from three vendors. Vendors are scheduled to present the demonstration and answer all project specific questions on 02/07/2017. **Hybrid Poles** • Vendor has been identified and a RFQ will be drafted and sent over by 02/03/2017. **Underground RFI** • Prototypes from 5 vendors have been procured in Q4 2016 and is currently undergoing testing. There is a possibility of a 6th vendor in upcoming weeks, however, all testing is expected to be completed by Q1 2017. **High Impedence Fault Detection** Following activities were accomplished during 2016 calendar year: • Enhanced system processes to accommodate lessons learn from various experiments; • Incorporated more advanced post processing algorithm utilizing variable windowing and thresholding to accurately identify discontinuities; • Designed prototype hardware and enclose to support extensive field testing; • Developed a SCADA interface to remotely control and monitor development hardware; and, • Expanded testing scenarios to include more complex and realistic circuit configurations.	Distribution Resources Plan, R.14-08-013; A.15-07-003 Integrated Demand-side Resource Program, R.14-10-003

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2nd triennial (2015-2017)	SCE	**System Intelligence and Situational Awareness Capabilities**	This project explores three areas of improvement in system intelligence and situational awareness. The first area of focus is on operator consoles. Substation and system events are not always isolated to a single piece of equipment. One anomaly can cause what is sometimes called the Christmas tree effect in which operator screens are inundated by an avalanche of alarms triggered by a single event. This makes it difficult for operators to find the source of a problem and make critical operations decisions. The second area of focus is Substation testing. Testing is a critical part of installing a substation system. Existing testing practices require tedious, manual step-by-step processes that can be very time consuming. Adoption of new tools and methods that reduce testing time will be explored and demonstrated. The third area of focus is demonstrating Process Bus technology. Advanced Technology (AT) is partnering with Engineering and Protection Automation Development to investigate IEC 61850 process bus technology to determine the feasibility of implementation on the SCE grid. Preliminary research by AT has shown there are many potential benefits but challenges in adopting the technology are significant. This project will investigate and test the conversion of existing hard-wired schemes to digital equivalents, in the areas of protection, automation, and configuration control. Additional benefits to systems engineering and testing will be explored. This project includes a laboratory demonstration of process bus technology. 2016 Milestone Achieved: Process Bus: Technical Evaluation document has been developed Laboratory test planning has begun with input from Protection Automation Development (PAD) Held numerous meetings with vendors and utilities which are using or plan on using IEC 61850 Process Bus The SEL process bus equipment has been delivered to AT lab and testing has been started SEL Process bus has been installed on the rack and testing has started Siemens process bus has been installed SEL Process bus Testing has started Continue to test process bus and learn valuable lessons on vendor (SEL, Siemens) implementations Optical CT vendor chosen. Lab unit to be acquired soon for testing Completed field conceptual design for optical CT installation	
2nd triennial (2015-2017)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration - Phase 2**	On October 26, 2016, the Energy Division directed the IOUs to submit a letter to the CPUC Executive Director requesting the following Phase 2 Pilot schedule changes without extending the duration of the Pilot: • Delay the start date for the Phase 2 Pilot from 11/1/2016 to 1/16/2017 • Shorten the Exclusivity Enrollment Period from 1/16/2017 to 2/28/2017 • Shorten the Open Enrollment Period from 3/1/2017 to 4/30/2017	Charge Ready Application A.14-10-014; Plug-In Electric Vehicle Submetering Pilot, Advice Letter 3198-E

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2nd triennial (2015-2017)	SCE	**Bulk System Restoration Under High Renewables Penetration**	In 2016, the team had numerous meetings both within the project team as well as with project stakeholders, sponsors, and advisors from SCE's Engineering, Planning, and Grid Operations groups to develop the detailed scope of work which culminated in the development of the Project Management Plan (PMP), which addresses the following. • A detailed Scope of Work statement • The project's work breakdown structure (WBS) and associated organization structure • The labor resource plan • A procurement plan that describes the materials and services that the project anticipates needing. • The project's milestone and deliverable schedule • The detailed project cost estimate Different equipment needed for Hardware in the loop testing was purchased. Also, transient models for solar PV and the system SVCs was modeled and tested. Due to organizational change within the group the project was canceled by Management.	
2nd triennial (2015-2017)	SCE	**Series Compensation for Load Flow Control**	For 2016, the intent of this project was to demonstrate the use of Thyristor Controlled Series Capacitors (TCSC) for load flow control on parallel transmission lines. The TCSC's was to provide system operators with the ability to precisely control the power flow on key transmission lines by rapidly adjusting impedances post-contingency. One objective of ths project was to selected a vendor to provide a Replica of Devers SVC control system and a Replica of TCSC control system. During the execution of the project plan, the benefits associated with the Series Compensation for Load Flow Control project were careful reviewed and SCE has decided to halt further development of the technology and to close out the project.	
2nd triennial (2015-2017)	SCE	**Versatile Plug-in Auxiliary Power System (VAPS)**	A Request for Proposal (RFP) was sent to 4 qualified vendors to supply a Class 8 flatbed truck with VAPS type electric power system, and after extensive review, US Hybrid in Torrance CA was selected. They will provide a flatbed on an International platform in 2017, followed by lab test prior to beginning fleet demonstration. Efficient Drivetrain Inc. (EDI) was identified as the sole viable suppler that would be able to meet all specifications for a light duty PHEV truck with VAPS system. A base model Chevrolet Sierra 3500 was purchased and received, and the procurement process to send the vehicle for upfit to EDI was started. EDI will upfit the vehicle and evaluation will begin in 2017. EDI was also identified to be the sole supplier for a medium duty PHEV flatbed VAPS system. SCE worked with EDI to create the necessary specification and received quotes for the base Peterbilt chassis and the flatbed body upfit. The base vehicle, flatbed installation, and upfit will be performed in 2017. For the small VAPS, the Altec Jobsite Energy Management System (JEMS) installed on a F550 Troubleman truck was received and performance testing was started. SCE requested and received from Altec a quote to install the JEMS 4A systems on F150 field service vehicles but the system did not meet all specifications and safety requirements. SCE is working with Altec to further refine the system to meet the requirements. A JEMS 4A base system was purchased and received to perform bench testing and long term evaluation testing. For the medium VAPS, SCE worked with Envoltz Inc. to evaluate a fully electric underground cable puller with VAPS type Li-ion battery system both in the lab and at two field demonstrations. The unit performed as designed and was well received by field crews. An order for one unit was	Charge Ready Application A.14-10-014; Plug-In Electric Vehicle Submetering Pilot, Advice Letter 3198-E
2nd triennial (2015-2017)	SCE	**Dynamic Power Conditioner**	For 2016, the DPC activities included speaking with several vendors to understand the current state of their technology and possible system offering for the ESS community. The team has also been discussing with other possible PCS vendors to get a more in-depth understanding of their upcoming PCS applications and roadmap. Along with understanding the current state of the market we have also been working on developing the technical requirements and SOW for our upcoming RFI and RFP.	

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2nd triennial (2015-2017)	SCE	**Optimized Control of Multiple Storage Systems**	In 2016, the Optimized Control of Multiple Storage Systems project continues to evaluate the requirements and the integration of multiple control strategies to optimize multiple energy storage scenarios. This projects looks to unlock the hidden benefits of having the ability of to demonstrate multiple energy storage controllers that will support the Integrated Grid Project and the SCE's Energy Storage Ownership Initiative (ESOI).	Energy Storage R,.15-03-011; D.14-10-040 & D.14-10-045 Resource Adequacy OIR, R.14-10-010
2nd triennial (2015-2017)	SCE	**DC Fast Charging Demonstration**	Planning was completed in Q1 2016. In order to demonstrate the feasibility and effectiveness of installing fast charging stations, initial planning was focused on assessing the impact of existing fast charging stations on the electric distribution system. A team of experts was assembled within SCE, and power quality monitoring equipment has been specified and purchased to instrument approximately 16 stations and collect data simultaneously. A schedule has been created to study 25 stations in SCE's territory. The installation of data logging equipment has begun, and the first site is instrumented and collecting data. Tesla's Buena Park Supercharger Station came online in Q4 2016 in conjunction with project monitoring, which allowed for some special tests to be performed in conjunction with Tesla. SCE is now coordinating efforts to install the remaining data logging equipment and get telemetry up and running for remote data acquisition. The installation of all 16 stations is estimated to be completed in Q2 of 2017, and then upon completion of assessment, additional stations will be instrumented and studied. The final analysis and report will be completed in late 2017. A preliminary system impact study of the Buena Park site was completed in Q4 2016 by SCE. The results are under review among SCE's experts to assess the information contained in the study.	Charge Ready Application A.14-10-014; Plug-In Electric Vehicle Submetering Pilot, Advice Letter 3198-E
2nd triennial (2015-2017)	SCE	**Integrated Grid Project II**	In 2016, the Integrated Grid Project (IGP) executed the RFP packages, contract awards, and the final procurements for core project elements including the control systems, integration bus, and the software required for lab testing. The following EPIC II activities were completed by the project team in 2016: • Completed initial RFP packages • Negotiated and awarded contracts to vendors • Received the controller software from vendors • Received the UIB (Utility Integration Bus) software • Received the lab test software	Distribution Resources Plan, R.14-08-013; A.15-07-003 Integrated Demand-side Resource Program, R.14-10-003