EPIC ADMINISTRATOR ANNUAL REPORT FOR 2025 ACTIVITIES

EPIC ADMINISTRATOR ANNUAL REPORT FOR 2025 ACTIVITIES

TABLE OF CONTENTS

1. Executive Summary

a) Overview of Programs/Plan Highlights

EPIC is funded by California utility customers under the auspices of the California Public Utilities Commission (Commission). 2025 represented the twelfth full year of implementing EPIC program operations since receiving Commission approval of SCE's EPIC 1 application[1] on November 19, 2013.[2] In 2025, SCE also reached its tenth full year of implementing program operations of SCE's 2015 – 2017 (EPIC 2) Investment Plan Application[3] (after receiving Commission approval on April 9, 2015),[4] its seventh full year of implementing program operations of SCE's 2018 – 2020 (EPIC 3) Investment Plan Application[5] (after receiving approval on October 25, 2018),[6] and its second year of implementing program operations of SCE's 2021 – 2025 (EPIC 4) Investment Plan[7] (receiving approval on November 30, 2023), [8] under which SCE has launched ten projects.

SCE is committed to achieving the State's decarbonization goals. SCE shared its plan to achieve these goals in the 2019 whitepaper "Pathway 2045," a data-driven analysis of the steps, including technology investments, that California must take to meet the 2045 goals to clean the State's electricity grid and reach carbon neutrality.[9] While SCE has since published updates to "Pathway 2045," SCE's overall technology strategy retains many of the core strategic goals from the original whitepaper. EPIC is a key part of SCE's technology strategy, supporting technology demonstrations and deployments which unlock significant value for ratepayers.

Throughout 2025, SCE made notable advancements across its EPIC project portfolio. Notable advancements include:

---

1 A.12-11-001.
2 D.13-11-025, OP 8.
3 A.14-05-005.
4 D.15-04-020, OP 1.
5 A.17-05-005.
6 D.18-10-052, OP 2.
7 A.22-10-001.
8 D.23-11-086, OP 1.
9 "Pathway 2045," November 2019 www.edison.com/clean-energy/pathway-2045

- Completing the Distributed Plug-In Electric Vehicle Charging Resources project, which successfully demonstrated advanced fast charging systems integrated with energy storage systems (ESS). Most fast-charging units currently cause unpredictable, intermittent high levels of demand. These dynamic demand characteristics affect utility planning and create challenges to high deployment of such systems due to their low load factor. Combining fast charging systems with energy storage would allow a higher load factor while still providing necessary service to customers. At its conclusion, the project showed a reduction in the impact of high-power charging on the distribution system, promising results that could warrant further work outside of the lab.
- Initiating SCE's EPIC Advisory Panel, consisting of Community Based Organization (CBO) representatives from SCE's service area, and holding five (5) workshops in 2025. At each workshop, SCE engaged community representatives, solicited feedback on its current and future projects, and provided input on how the projects might support community needs. Following each workshop, SCE applied a structured framework to intake, review and, where possible, incorporate feedback into EPIC projects. Moreover, SCE shared the results of this analysis with panelists at subsequent meetings.
- Launching five new EPIC 4 projects that advance EPIC 4 initiatives and aim to benefit Low Income and Disadvantaged and Vulnerable Communities (DVCs).
    - Autonomous and Adaptive Grid (A2G) Operational Efficiencies will advance grid modernization through targeted digital tools and analytics that strengthen reliability, enhance public safety, and improve operational efficiency, delivering direct benefits to ratepayers.
    - Communication Assisted Protection Technologies for Inverter-based Networks (CAPTIN) will evaluate new communication assisted protection technologies for systems with high penetration of inverter-based resources (IBRs).
    - Industrial Demand Flexibility Enabling Distribution Grid Autonomous Resilience (IDF-EDGAR) aims to enable SCE's Distributed Energy Resource Management

    System (DERMS) to monitor and control customer-owned Distributed Energy Resources (DERs), demonstrate DER orchestration to obtain distribution grid load flexibility, demonstrate dynamic pricing at an industrial customer, and demonstrate a CSIP IEEE 2030.5 (or direct DERMS command) based DER integration.
  - Local Optimization and Grid Edge Management Systems (LO-GEMS) will showcase advanced AMI hardware and control systems, along with integrated platforms that connect with customers. Based on customer preferences, it will optimize energy use and generation to lower costs and enable sharing of flexibility data with the DERMS platform to boost grid capacity and reliability.
  - Thermally Optimized Advanced Duct Strategy (TOADS) aims to address duct bank overheating by evaluating sensors, cooling methods, construction materials, and duct bank configurations through modeling, deployment, and real-world testing.
- Please refer to Section 4.b) for accomplishments, success stories, and updates from SCE's other active EPIC projects.

A key emphasis across SCE's EPIC projects is ensuring that the lab and field testing provide sufficient results to assess if new technologies meet SCE's requirements before deploying them into a pilot or field operation.

In addition, despite encountering challenges such as delays in procurement, vendor resistance to EPIC IP flowdowns, and vendors unexpectedly ending production or support for key products in projects, SCE's EPIC project teams have effectively managed these setbacks and continue to drive the projects to completion.

In this report, SCE separately presents the highlights from its EPIC I (2012 – 2014), EPIC II (2015 – 2017), EPIC III (2018 – 2020), and EPIC IV (2021 – 2025) Investment Plans.

(1) 2012 – 2014 Investment Plan

Between January 1 and December 31, 2025, for the 2012 – 2014 Investment Plan, SCE did not incur any expenses for its EPIC 1 program; cumulative expenses over the span of its 2012 – 2014 Investment Plan amount to $38,642,227.

SCE executed 16 projects from its approved EPIC 1 portfolio. This includes the completion of three projects in 2015, four projects in 2016, four projects in 2017, two projects in 2018, two projects in 2019 and one project in 2020. A list of completed projects is included in the Conclusion of this Report (Section 5). In accordance with the Commission's directives,[10] SCE prepared Final Project Reports for each completed project and included them in the Annual Reports according to the years in which the projects were completed. All EPIC 1 projects are complete as of the year 2020.

(2) 2015 – 2017 Investment Plan

Between January 1 and December 31, 2025, for the 2015 – 2017 Investment Plan, SCE spent $951,541 toward project costs and $171,044 toward administrative costs for a grand total of $1,122,584. SCE's cumulative expenses for its 2015 – 2017 Investment Plan amount to $40,559,807. SCE committed $182,449 toward projects and encumbered $289,761 through executed purchase orders during this period. SCE had no uncommitted EPIC 2 funding as of December 31, 2025.

SCE initiated 13 projects from its approved EPIC 2 portfolio. One project, System Intelligence and Situational Awareness Capabilities, remains in execution in 2026. As of December 31, 2025, three projects have been cancelled for the reasons described in their respective project updates sections in previous annual reports. Project execution activities continued for the remaining 10 projects. Of those 10 projects, SCE completed one project in 2017, three projects in 2018, two projects in 2019, one project in 2020, one project in 2021, and one project in 2022.

(3) 2018 – 2020 Investment Plan

Between January 1 and December 31, 2025, for the 2018 – 2020 Investment Plan, SCE expended a total of $4,077,941 toward project costs and $168,016 toward administrative costs for a grand total of $4,245,956. SCE's cumulative expenses over the span of its 2018 – 2020 Investment Plan

[10] D.13-11-025, OP 14.

amount to $32,757,919. SCE committed $5,929,898 toward projects and encumbered $ 3,022,792 through executed purchase orders during this period. SCE had no uncommitted EPIC 3 project funding as of December 31, 2025. In previous annual reports, SCE communicated the history of its EPIC 3 portfolio and changes to its project mix.[11] One incremental change since the 2024 Annual Report is the completion of the Distributed Plug-In Electric Vehicle Charging Resources. SCE continues to perform work on its active EPIC 3 projects.

SCE continues to perform work on the remaining nine projects. The following 9 projects from the EPIC 3 portfolio remain in execution:

1. Advanced Technology for Field Safety (ATFS)
2. Beyond Lithium-ion Energy Storage Demo
3. Next Generation Distribution Automation III
4. SA-3 Phase III Field Demonstrations
5. Service and Distribution Centers of the Future
6. Smart City Demonstration
7. Storage-Based Distribution DC Link
8. Vehicle-to-Grid Integration Using On-Board Inverter
9. Wildfire Prevention & Resiliency Technology Demonstration

(4) <u>2021 – 2025 Investment Plan</u>

Between January 1 and December 31, 2025, for the 2021 – 2025 Investment Plan, SCE expended a total of $4,408,935 toward project costs and $597,649 toward administrative costs for a grand total of $5,006,584. SCE's cumulative expenses over the span of its 2021 – 2025 Investment Plan amount to $5,108,080. SCE committed $61,573,094 toward projects and encumbered $2,059,507 through executed purchase orders during this period. SCE budgeted $68,051,325 to ten (10) EPIC 4 projects out of its total EPIC 4 project budget of $68,051,325 as of December 31, 2025. SCE had no uncommitted EPIC 4 project funding as of December 31, 2025.

---

[11] SCE 2024 EPIC Annual Report

SCE initiated five new projects in 2025 based on the Strategic Initiatives and Research Topics approved in the 2021 – 2025 Investment Plan. The following ten projects from the EPIC 4 portfolio remain in execution:

1. A2G Operational Efficiencies
2. Communication Assisted Protection Technologies for Inverter-based Networks (CAPTIN)
3. Flexible Alternating Current System (FACS)
4. Industrial Demand Flexibility Enabling Distribution Grid Autonomous Resilience (IDF-EDGAR)
5. Local Optimization & Grid Edge Management Systems (LO-GEMS)
6. ML-Augmented Digital Simulation (MAD-S)
7. Quantum Networking
8. Stability Improvement with DERs (SIDER)
9. Swift Electrification of Transit (SET)
10. Thermally Optimized Advanced Duct Strategy (TOADS)

2. Introduction and Overview

a) EPIC Background

In Decision (D.)12-05-037, the Commission established the EPIC Program to fund applied research and development, technology demonstration and deployment (TD&D), and market facilitation programs to provide ratepayer benefits. This Decision further stipulated that the EPIC Program would continue through 2020[12] with an annual budget of $162 million,[13] adjusted for inflation.[14] Approximately 80% of the EPIC budget is administered by the California Energy Commission (CEC), and 20% is administered by the investor-owned utilities (IOUs). Additionally, 0.5% of the total EPIC budget funds

[12] D.12-05-037, OP 1.
[13] D.12-05-037, OP 7.
[14] Using the Consumer Price Index.

Commission oversight of the Program.[15] The IOUs are limited to performing TD&D activities.[16] SCE was allocated 41.1% of the IOU portion of the budget and administrative activities.[17]

The Commission approved SCE's 2012 – 2014 Investment Plan[18] in D.13-11-025 on November 19, 2013. SCE submitted its 2015 – 2017 Investment Plan Application[19] on May 1, 2014, and the Commission approved the Application in D.15-04-020 on April 9, 2015. SCE submitted its 2018 – 2020 Application[20] on May 1, 2017, and the Commission approved the Application in D.18-10-052 on October 25, 2018.

In 2019, the Commission initiated a two-phase rulemaking[21] to determine the future of EPIC. In Phase 1 the Commission determined that EPIC would continue for ten years through 2030, and that each investment period would span five years (2021 – 2025 and 2026 – 2030). Additionally, the Commission authorized the CEC to continue its EPIC administrator role.[22] In Phase 2 of the rulemaking, the Commission determined that the IOUs should continue their roles as EPIC Administrators, along with the CEC.[23] SCE (along with PG&E and SDG&E) filed its EPIC 4 Investment Plan, covering 2021 – 2025, on October 1, 2022, [24] and the Commission approved the Application in D.23-11-086 on November 30, 2023. SCE is currently executing its 2015 – 2017, 2018 – 2020 and 2021 – 2025 EPIC Investment Plans.

Per D.23-04-042, the EPIC Program Administrators are to file annual reports on April 30 of each year, via a Tier 2 Advice Letter that follows the outline in Appendix C.[25]

b) SCE Technology Strategy and the Role of EPIC

SCE's EPIC activities support and are informed by SCE's broader, long-term technology strategy. Foundational SCE whitepapers, the Technology Roadmap, and active EPIC projects align with

---

15 *Id*, OP 5.
16 *Id*.
17 D.12-05-037, OP 7, as modified by D.12-07-001.
18 A.12-11-004.
19 A.14-05-005.
20 A.17-05-005
21 R.19-10-005.
22 D.20-08-042.
23 D.21-11-028.
24 A.22-10-001.
25 D.23-04-042, OP 8.

CPUC EPIC 5 Strategic Goals, the Electricity Value Chain[26], and key CPUC proceedings illustrating how EPIC investments contribute to system-level outcomes.

EPIC is a critical part of SCE's technology strategy. SCE released several whitepapers that outline its overall technology strategy, starting with the 2017 paper "The Clean Power and Electrification Pathway,"[27] which introduces SCE's blueprint to reduce greenhouse gas emissions and air pollutants. SCE further refined its vision in 2019 when it published "Pathway 2045,"[28] an in-depth analysis to identify a feasible and economical route to realizing California's GHG reduction goals and achieve carbon neutrality in California at the lowest reasonable cost by 2045. Many of the key pillars introduced in the two whitepapers plus those from subsequent whitepapers overlap closely with the CPUC's five EPIC 5 Strategic Goals. Table 1 below shows that many of the CPUC's EPIC 5 Strategic Goals are consistent with decarbonization priorities SCE has been pursuing for years, as reflected in prior SCE whitepapers; for more information about SCE's climate whitepapers, please visit www.edison.com/clean-energy.

Table 1: Alignment of CPUC EPIC 5 Strategic Goals with SCE Decarbonization Targets

EPIC 5 Strategic Goals[29]	SCE Decarbonization Targets
1) Transportation Electrification	"The Pathway calls for at least 24 percent of these vehicles — 7 million — to be electrified by 2030. EVs charging from an increasingly clean electric grid can help reduce transportation sector GHG emissions from 169 to 111 MMT/year, one-third of the 2030 goal."[30] "Three-quarters of light-duty vehicles, two-thirds of medium-duty vehicles and one-third of heavy-duty vehicles will need to be electric by 2045."[31]

[26] D.12-05-037, at p. 12, OP 12.

[27] "The Clean Power and Electrification Pathway," November 2017 www.edison.com/content/dam/eix/documents/our-perspective/g17-pathway-to-2030-white-paper.pdf.

[28] "Pathway 2045," November 2019 www.edison.com/clean-energy/pathway-2045.

[29] D.24-03-007, OP 1 and Appendix A.

[30] "The Clean Power and Electrification Pathway," November 2017.

[31] "Pathway 2045," November 2019.

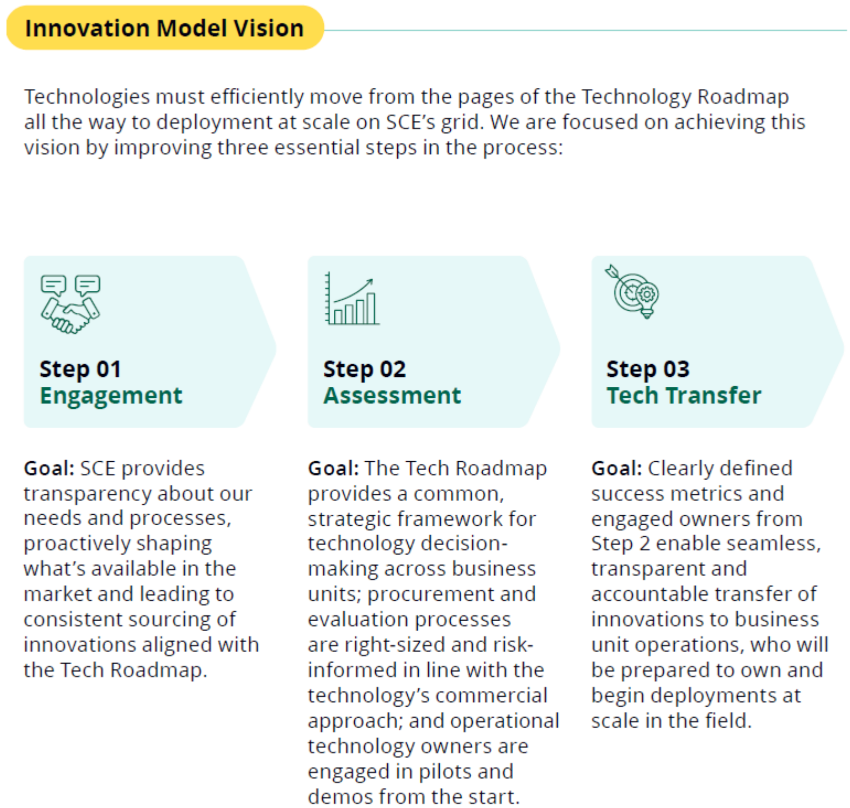
EPIC 5 Strategic Goals[29]	SCE Decarbonization Targets
2) Distributed Energy Resource Integration	"Eighty gigawatts (GW) of new utility-scale clean generation and 30 GW of utility-scale energy storage will be required in the next 25 years. Energy storage will be essential because the most cost-effective, carbon-free generation sources — wind and solar — are intermittent. Thirty additional GW of generation capacity and 10 GW of storage will come from distributed energy resources (DERs)"[32]
3) Building Decarbonization	"Space and water heating currently contributes more than two-thirds of total residential and commercial building GHG emissions. Electrifying nearly one-third of residential and commercial space and water heaters, in addition to increased energy efficiency and strong building codes and standards, could reduce GHG emissions from this sector from 49 to 37 MMT/year, or 7 percent of the 2030 goal."[33] "Building electrification will increase electric load nearly 50 TWh by 2045 — representing almost 15% of the total 2045 grid load."[34]
4) Achieving 100 Percent Net-Zero Carbon and the Coordinated Role of Gas	"The industrial sector reduces GHG emissions from 101 MMT CO2e (CO2 equivalent) to 74 MMT CO2e by 2030, and to 37 MMT CO2e by 2045, through a 40% reduction of methane emissions, a 35% reduction of gasoline production and 70% electrification of HVAC systems, in addition to use of low-carbon fuels for process heat."[35]
5) Climate Adaptation	"…by 2050, wildfires could take out full corridors of transmission, leaving large swaths of customers without service for long periods; critical substations in flood plains could become inundated due to more extreme precipitation events; and the grid could have up to 20% reduced capacity in some areas due to increased extreme temperatures. To meet this new reality, infrastructure must be designed to withstand more intense storm surges and flooding, and new transmission lines must be constructed."[36]

Thus, CPUC's efforts in EPIC, including the CPUC's EPIC 5 Strategic Goals, have a strong connection with SCE's overall strategy, and SCE's EPIC TD&D projects play a vital role in advancing SCE's technology strategy.

32 "Pathway 2045," November 2019.
33 "The Clean Power and Electrification Pathway," November 2017.
34 "Pathway 2045," November 2019.
35 *Ibid*.
36 "Adapting for Tomorrow: Powering a Resilient Future," May 2022 www.edison.com/clean-energy/adapting-for-tomorrow.

SCE established a Technology Roadmap to further define its overall technology strategy. Recognizing the importance of sharing this vision with the broader industry and the vendor community, SCE published its "Partner's Guide to the SCE Technology Roadmap," which shares a comprehensive vision of the technologies to transform SCE's energy system, enabling greater collaboration with innovators and other industry stakeholders.[37] The SCE Roadmap is a signal to the industry of the core areas that SCE believes are most beneficial to customers. SCE hosted a Grid Digitalization vendor summit in late 2025 following which, and based on the Roadmap, vendors submitted around 100 project proposals that SCE will evaluate to incorporate into SCE's capital and EPIC-funded projects. The whitepapers, the "Partners Guide," and the solicitation and incorporation of vendor "best ideas" are examples of how SCE is sharing its broader technology strategy to build stronger industry partnerships. EPIC is a critical driver of that process. Table 2 illustrates how SCE's active EPIC projects align with the electricity value chain, consistent with D.12-05-037,[38] and the Technology Roadmap, which guided past EPIC project decisions and is contributing to SCE's EPIC 5 Investment Plan.

Figure 1: SCE Innovation Model, "Partner's Guide to the Technology Roadmap"



[37] "Partner's Guide to the SCE Technology Roadmap," January 2025, https://on.edison.com/techroadmap.
[38] D.12-05-037, at p. 12, OP 12.

Table 2: Alignment of Electricity Value Chain to SCE's Active EPIC Projects and SCE Technology Roadmap

Electricity System Value Chain[39]	SCE's EPIC Projects	SCE Technology Roadmap Tech Class[40]
	EPIC 2	
Distribution	System Intelligence and Situational Awareness Capabilities	Grid Intelligence
	EPIC 3	
Grid operations/market design;	Advanced Technology for Field Safety (ATFS)	Grid Intelligence
Distribution	Beyond Lithium-ion Energy Storage Demo	Advanced Energy Storage
Distribution	Next Generation Distribution Automation III	Grid Comms, Grid Cybersecurity
Transmission	SA-3 Phase III Field Demonstrations	Advanced Structures
Distribution	Service and Distribution Center of the Future	Secondary Distribution Tech
Grid Operation/Market Design	Smart City Demonstration	Secondary Distribution Tech
Distribution	Storage-Based Distribution DC Link	Direct Current (DC) Systems
Distribution	Vehicle-to-Grid Integration Using On-Board Inverter	Demand Flexibility
Grid Operation/Market Design	Wildfire Prevention & Resiliency Technology Demonstration	Grid Intelligence
	EPIC 4	
Grid Operation/Market Design	A2G Operational Efficiencies	Grid Computing
Distribution	Communication Assisted Protection Technologies for Inverter-based Networks (CAPTIN)	Grid Flex & Advanced Protection
Distribution	Flexible Alternating Current System (FACS)	Grid Flex & Advanced Protection
Demand Side Management	Industrial Demand Flexibility Enabling Distribution Grid Autonomous Resilience (IDF-EDGAR)	Demand Flexibility
Demand Side Management	Local Optimization & Grid Edge Management Systems (LO-GEMS)	Intelligent Service Point
Grid Operation/Market Design	ML-Augmented Digital Simulation (MAD-S)	Grid Computing

39 *Ibid.*

40 "Partner's Guide to the SCE Technology Roadmap," January 2025.

Electricity System Value Chain[39]	SCE's EPIC Projects	SCE Technology Roadmap Tech Class[40]
Grid Operation/Market Design	Quantum Networking	Grid Cybersecurity
Demand Side Management	Stability Improvement with DERs (SIDER)	Demand Flexibility, Intelligent Service Point
Distribution	Swift Electrification of Transit (SET)	Secondary Distribution Tech
Distribution	Thermally Optimized Advanced Duct Strategy (TOADS)	Grid Sensors

Therefore, EPIC is not a standalone research effort, but a core enabler of SCE's long-term technology and decarbonization strategy. The alignment between longstanding SCE strategic priorities, active EPIC projects, the Technology Roadmap, and the CPUC's EPIC 5 Strategic Goals demonstrates continuity across past, present, and future investment decisions. By situating EPIC activities within this broader strategic framework, SCE aims to provide greater transparency into how EPIC-funded research supports system-wide outcomes and informs future EPIC 5 planning.

c) EPIC Program Components

The Commission limited SCE's triennial investment applications in the EPIC Program to TD&D projects, per D.12-05-037 and reiterated in D.21-11-028. The Commission defines TD&D projects as installing and operating pre-commercial technologies or strategies at a sufficiently large scale, and in conditions sufficiently reflective of anticipated actual operating environments, to enable appraisal of the operational and performance characteristics and the associated financial risks.[41]

For administration of their EPIC 1-3 Portfolios, the IOUs successfully utilized the joint IOU framework developed for the 2012 – 2014 cycle (EPIC 1) and enhanced for the 2015 – 2017 (EPIC 2) and 2018 – 2020 (EPIC 3) cycles with updated strategic initiatives to support the latest key drivers and policies. This included 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, 2015 – 2017, and 2018 – 2020

[41] D.12-05-037, OP 3.B.

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 adoption of low-emission vehicles and economic development for ratepayers.

For the EPIC 4 Investment Plan, the IOUs coordinated their respective EPIC 4 Plans to use the same structure that the CEC's EPIC 4 Investment Plan applied to technology demonstration areas. Furthermore, IOU administrators have followed the Commission's guidance to file at the Initiative level. Thus, SCE's EPIC 4 Investment Plan was organized under three Strategic Objectives: (1) Create a More Nimble Grid to Maintain Reliability as California Transitions to 100 Percent Clean Energy, (2) Increase the Value Proposition of Distributed Energy Resources to Customers and the Grid, and (3) Guide California's Transition to a Zero-Carbon Energy System that is Climate-Resilient and Meets Environmental Goals. Within these Strategic Objectives, SCE proposed six Strategic Initiatives, which are specific opportunities and/or challenges: T&D Foundational Technologies, T&D Situational Capabilities, Energy Management Foundational Technologies, Energy Management Situational Capabilities, Vulnerabilities, Threats and Hazard Reduction, and Digital Transformation. In addition, SCE described Research Topics which consider potential project activities in these areas. In 2025, SCE launched five new projects that support EPIC 4's Strategic Objectives, Strategic Initiatives, and Research Topics, bringing SCE's total EPIC 4 projects to ten projects and committing all of SCE's EPIC 4 budget.

As CPUC looks ahead to EPIC 5, CPUC has identified five Strategic Goals: (1) Transportation Electrification, (2) Distributed Energy Resource Integration, (3) Building Decarbonization, (4) Achieving 100 Percent Net Zero Carbon and the Coordinated Role of Gas, and (5) Climate Adaptation.[42]

SCE values the opportunity to continue playing a critical role as an EPIC administrator for EPIC 5, and appreciates that the Commission, in D.26-02-037,[43] reaffirmed the IOUs' role as EPIC 5 Administrators, along with the CEC. SCE looks forward to aligning its EPIC 5 Investment Plan with these Strategic Goals.

[42] D.24-03-007, OP 1.
[43] D.26-02-037, OP 2.

These Goals are supported by CPUC Proceedings.[44] SCE aims to align its projects with CPUC proceedings. For example, Table 1 shows how SCE's active EPIC projects, from EPIC 2, EPIC 3 and EPIC 4, align with the proceedings that contributed to the EPIC 5 Strategic Goals:

Table 3: Alignment of SCE's Active EPIC Projects with CPUC Proceedings

Proceedings and Description	CPUC EPIC 5 Goals	Active SCE EPIC Projects
R.23-12-008 Transportation Electrification Policy and Infrastructure R.22-07-005 Advance Demand Flexibility Through Electric Rates R.21-06-017 Modernize the Electric Grid for a High Distributed Energy Resources Future R.18-12-006 Development of Rates and Infrastructure for Vehicle Electrification R.24-01-018 Establish Energization Timelines	1. Transportation Electrification	**EPIC 3** • Distributed Plug-In Electric Vehicle Charging Resources • Next Generation Distribution Automation III • Service and Distribution Center of the Future • Smart City Demonstration • Vehicle-to-Grid Integration Using On-Board Inverter **EPIC 4** • Communication Assisted Protection Technologies for Inverter-based Networks (CAPTIN) • Stability Improvement with DERs (SIDER) • Swift Electrification of Transit (SET) • Thermally Optimized Advanced Duct Strategy (TOADS)

[44] EPIC Strategic Workshop Process, Kick-Off Workshop. March 19, 2024, https://epicpartnership.org/strategicobjectives.html

Proceedings and Description	CPUC EPIC 5 Goals	Active SCE EPIC Projects
R.26-04-009 Order Instituting Rulemaking on California Advanced Electric Rate Design R.24-01-017 California Renewables Portfolio Standard Program R.22-11-013 Distributed Energy Resource Program Cost-Effectiveness Issues, Data Access and Use, and Equipment Performance Standards R.22-07-005 Advance Demand Flexibility Through Electric Rates R.21-06-017 Modernize the Electric Grid for a High Distributed Energy Resources Future R.20-05-003 Continue Electric Integrated Resource Planning and Related Procurement Processes R.19-09-009 Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies R.18-07-003 California Renewables Portfolio Standard Program R.17-07-007 Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21	2. Distributed Energy Resource Integration	**EPIC 3** • Advanced Technology for Field Safety (ATFS) • Beyond Lithium-ion Energy Storage Demo • Control and Protection for Microgrids and Virtual Power Plants • Distributed Plug-In Electric Vehicle Charging Resources • Next Generation Distribution Automation III • Smart City Demonstration • Storage-Based Distribution DC Link • Vehicle-to-Grid Integration Using On-Board Inverter **EPIC 4** • Communication Assisted Protection Technologies for Inverter-based Networks (CAPTIN) • Flexible Alternating Current System (FACS) • ML-Augmented Digital Simulation (MAD-S) • Quantum Networking • Swift Electrification of Transit (SET) • Stability Improvement with DERs (SIDER) • Thermally Optimized Advanced Duct Strategy (TOADS)

<table>
<tr><th>Proceedings and Description</th><th>CPUC EPIC 5 Goals</th><th>Active SCE EPIC Projects</th></tr>
<tr><td>R.26-04-009 Order Instituting Rulemaking on California Advanced Electric Rate Design
R.22-07-005 Advance Demand Flexibility Through Electric Rates
R.19-01-011 Building Decarbonization</td><td>3. Building Decarbonization</td><td>EPIC 2
• System Intelligence and Situational Awareness Capabilities

EPIC 3
• Next Generation Distribution Automation III
• SA-3 Phase III Field Demonstrations
• Service and Distribution Centers of the Future Smart City Demonstration
• Vehicle-to-Grid Integration Using On-Board Inverter
• Wildfire Prevention & Resiliency Technology Demonstration

EPIC 4
• Flexible Alternating Current System (FACS)
• Industrial Demand Flexibility Enabling Distribution Grid Autonomous Resilience (IDF-EDGAR)
• Local Optimization & Grid Edge Management Systems (LO-GEMS)
• ML-Augmented Digital Simulation (MAD-S)
• Quantum Networking
• Stability Improvement with DERs (SIDER)</td></tr>
<tr><td>R.20-05-003 Continue Electric Integrated Resource Planning and Related Procurement Processes
R.20-01-007 Long-Term Gas System Planning</td><td>4. Achieving 100 percent Net Zero Carbon and the Coordinated Role of Gas</td><td>EPIC 2
• System Intelligence and Situational Awareness Capabilities

EPIC 3
• Advanced Technology for Field Safety (ATFS)
• Beyond Lithium-ion Energy Storage Demo
• Next Generation Distribution Automation III
• SA-3 Phase III Field Demonstrations
• Storage-Based Distribution DC Link

EPIC 4
• Flexible Alternating Current System (FACS)
• Industrial Demand Flexibility Enabling Distribution Grid Autonomous Resilience (IDF-EDGAR)
• Local Optimization & Grid Edge Management Systems (LO-GEMS) ML-Augmented Digital Simulation (MAD-S)</td></tr>
</table>

Proceedings and Description	CPUC EPIC 5 Goals	Active SCE EPIC Projects
R.18-04-019 Strategies and Guidance for Climate Change Adaptation	5. Climate Adaptation	**EPIC 3** • Advanced Comprehensive Hazards Tool • Advanced Technology for Field Safety (ATFS) • Smart City Demonstration • Wildfire Prevention & Resiliency Technology Demonstration **EPIC 4** • A2G Operational Efficiencies • ML-Augmented Digital Simulation (MAD-S)

As described in Table 4 and in the Project Status Reports in Section 4 b), SCE's active EPIC projects also align with EPIC's Mandatory Guiding principle to provide ratepayer benefits, defined as: (1) improving safety, (2) increasing reliability, (3) increasing affordability, (4) improving environmental sustainability, and (5) improving equity, all as related to California's electric system.[45]

Table 4: Alignment of SCE's Active EPIC Projects with EPIC Mandatory Guiding Principle

	EPIC Mandatory Guiding Principles				
SCE's EPIC Projects	**Improve Safety**	**Increase Reliability**	**Increase Affordability**	**Improve Environmental Sustainability**	**Improve Equity**
EPIC 2					
System Intelligence and Situational Awareness Capabilities	X	X	X	X	
EPIC 3					
Advanced Technology for Field Safety (ATFS)	X	X	X	X	
Beyond Lithium-ion Energy Storage Demo		X	X	X	X
Control and Protection for Microgrids and Virtual Power Plants		X		X	
Distributed Plug-In Electric Vehicle Charging Resources		X	X	X	
Next Generation Distribution Automation III	X	X	X	X	X

45 D.21-11-028 at OP 2 and at Appendix A.

	EPIC Mandatory Guiding Principles				
SCE's EPIC Projects	**Improve Safety**	**Increase Reliability**	**Increase Affordability**	**Improve Environmental Sustainability**	**Improve Equity**
SA-3 Phase III Field Demonstrations	X	X	X		
Service and Distribution Center of the Future	X	X	X	X	
Smart City Demonstration		X	X	X	X
Storage-Based Distribution DC Link		X	X	X	
Vehicle-to-Grid Integration Using On-Board Inverter		X		X	X
Wildfire Prevention & Resiliency Technology Demonstration	X	X		X	X
EPIC 4					
A2G Operational Efficiencies	X	X	X		X
Communication Assisted Protection Technologies for Inverter-based Networks (CAPTIN)	X	X		X	
Flexible Alternating Current System (FACS)	X	X	X	X	X
Industrial Demand Flexibility Enabling Distribution Grid Autonomous Resilience (IDF-EDGAR)		X	X	X	
Local Optimization & Grid Edge Management Systems (LO-GEMS)		X	X	X	X
ML-Augmented Digital Simulation (MAD-S)	X	X	X		
Quantum Networking	X	X			
Stability Improvement with DERs (SIDER)	X	X		X	
Swift Electrification of Transit (SET)		X	X	X	X
Thermally Optimized Advanced Duct Strategy (TOADS)		X	X	X	

d) Coordination

The Utility EPIC Administrators met regularly to discuss the items mentioned above, coordinate investment plan activities, and plan and coordinate joint stakeholder workshops and the annual joint public symposium. Moreover, SCE participated in regular collaborative meetings with the CEC to help further coordinate the respective investment plans.

The EPIC Administrators collaborated throughout 2025 on the execution of the 2015 – 2017 (EPIC 2), 2018 – 2020 (EPIC 3) and 2021 – 2025 (EPIC 4) Investment Plans. Specific examples of the Administrators' coordination include the following in-person events: the EPIC 4 Wave 2 Project Workshop (September 30, 2025), the Joint Utilities EPIC Workshop (July 15, 2025) and the 2025 EPIC Symposium (October 7, 2025).

As part of the EPIC 3 Next Generation Distribution Automation III (NGDA3) project, SCE shared findings on the limitations and deficiencies of the DNP3-SAv5 protocol with the DNP Users Group. The DNP Users Group is a California public mutual benefit nonprofit Corporation, whose primary purpose is to maintain and promote the Distributed Network Protocol (DNP3), a non-proprietary, standards-based communication protocol widely used in the utility industry.[46] SCE's findings provided extremely valuable information to improve the design of a new protocol, DNP3-SAv6, to address the shortcomings in DNP3-SAv5.

SCE successfully established and ran a Technical Advisory Board (TAB), open to all interested parties, to discuss Vehicle to Grid (V2G) areas of interest to support the EPIC 3 project Vehicle-to-Grid Integration Using On-Board Inverter (V2G), GT-18-0015. As part of the V2G project, SCE worked with standards organizations to help advance relevant standards, working with industry to demonstrate and validate methods to ensure successful implementation.

SCE is also a member of the vPAC (Virtual Protection Automation and Control) Alliance, which aims to accelerate the creation of a standards-based, open, interoperable, and secure architecture. SCE actively contributes to multiple working groups within the alliance to develop a set of specifications for virtualized protection automation & control.

---

[46] www.dnp.org/About/DNP-Users-Group

Following these successful collaborations, and on request from other administrators and partners, SCE is looking forward to expanding the use of TABs to other topic areas to collaborate in support of projects by all EPIC Administrators.

SCE also engages with the broader community. SCE's EPIC 4 Investment Plan aims to incorporate the CPUC Environmental Social Justice (ESJ) Action Plan, the Distributed Energy Resources (DER) Action Plan, and federal Justice 40 elements into its project design and execution.
Highlights of SCE’s plan to work with our communities include:

- Coordinating with the overarching EPIC Community Advisory Panel, made up of grassroots stakeholders, who will discuss siting and community benefits opportunities and provide input on project design and investment plans,
- Implementing processes to integrate equity and access features into individual projects,
- Seeking to site field use case projects in disadvantaged communities that will most benefit from the project and work to incorporate measurable community benefits into success measures,
- Seeking to incorporate local education into the project that benefit the adjacent or greater community, and
- Hosting project initiation workshops to create awareness and opportunities to work with the community.

SCE had success with its EPIC Community Advisory Panel, where CBOs were invited to provide feedback on SCE’s EPIC projects as paid panelists. SCE hosted five (5) workshops, in person and virtually, with the Panel in 2025. SCE project leaders presented EPIC 4 projects to panelists as the projects progressed through the stages of ideation, initiation, planning, and execution. The workshops emphasized interactive discussion and followed a structured process to capture panelist feedback. SCE subsequently held dedicated follow-up meetings with project technical leads to review the feedback and then presented resulting actions and follow-up items to the panelists. Furthermore, to provide context to the EPIC projects, SCE hosted teach-ins at the workshops, including site tours, about the overall grid, grid equipment and maintenance, and laboratory activities. SCE looks forward to continuing to engage its community members in support of EPIC 5.

SCE also set up a workshop to discuss its EPIC activities with the Native American communities SCE serves, consistent with Advice Letter 5357-E.[47] The EPIC program team and SCE's Tribal Nations Liaison collaborated to build the workshop and outreach to tribal communities in SCE's coverage area. Tribal interest in EPIC was minimal, as tribal communities were, at the time, having discussions in other priorities. SCE values input from tribal communities as EPIC moves to a new 2026 – 2030 Investment cycle (EPIC 5).

Furthermore, SCE is locating EPIC 4 projects launched in 2024 (Wave 1) in communities identified as disadvantaged and low-income communities;[48] these communities will benefit as the projects seek to address problems like power quality, access to EV charging infrastructure, and better integration of clean- energy DERs. The Wave 1 projects already account for more than the minimum thresholds from D.23-04-042,[49] and SCE is considering additional work in Disadvantaged and Vulnerable Communities (DVCs) or low-income communities as it moves forward with the new EPIC 4 projects it launched in 2025.

Finally, SCE continues to support the Policy + Innovation Coordination Group (PICG) database and provides quarterly updates on its ongoing EPIC projects to the PICG database website (www.epicpartnership.org).

---

[47] SCE Advice Letter 5357-E, August 9, 2024, at 7.

[48] California Energy Commission, "Low-Income or Disadvantaged Communities Designated by California," https://cecgis-caenergy.opendata.arcgis.com/datasets/CAEnergy::low-income-or-disadvantaged-communities-designated-by-california-1

[49] D.23-04-042, OP 2: Beginning with the Electric Program Investment Charge (EPIC) 4 Investment Plans, EPIC Administrators shall consider the California Public Utilities Commission's (Commission) Environmental and Social Justice Action Plan, the Commission's Distributed Energy Resources Action Plan, and the federal Justice40 Initiative when developing EPIC investment plans. The EPIC 4 Investment Plans shall dedicate at least 25 percent of technology demonstration and deployment (TD&D) funds toward projects located in and benefitting disadvantaged communities and at least an additional 10 percent allocation of TD&D funds toward projects located in and benefitting low-income communities. In their annual reports, EPIC Administrators shall indicate how their investment plans meet the standards set in these initiatives.

e) Transparent and Public Process/CEC Solicitation Activities

In 2025, SCE hosted and supported numerous public workshops to make its EPIC activities transparent. SCE shared its second wave of EPIC 4 project proposals in a public workshop on September 30, 2025, before launching them. SCE coordinated with the other EPIC IOU Administrators to present the EPIC Joint Utilities Workshop on July 15, 2025, and then supported the CEC's Annual EPIC Symposium on October 7, 2025.

SCE supported numerous parties applying for CEC EPIC funding in 2025. SCE received a total of 62 requests for Letters of Support (LOS) and Letters of Commitment (LOC) from a diverse array of parties, including private vendors, universities, and national laboratories, showing interest in partnering on their bids for CEC EPIC projects. Of these 62 requests, SCE provided LOS for 26 and LOC for 7. Three (3) LOC and two (2) LOS were approved by the CEC, and another 19 are still actively being reviewed for award.

For SCE, a LOS typically supports the premise of a project. In some instances, it will infer technical advisory support if the project is awarded to the recipient and if the party and SCE come to a mutual understanding of what advisory support will be required. A LOC includes early financial and/or technical support in the event that the project is 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, www.sce.com/regulatory/regulatory-information/epic, where they can view SCE's Investment Plan Applications and directly contact SCE with questions pertaining to EPIC. In addition, stakeholders may contact SCE directly from the EPIC webpage or at ideas.sce.com to request a LOS or LOC or to make a project proposal.

3. Budget

a) Authorized Budget

(1) 2012 – 2014 Investment Plan

Table 5: 2012 – 2014 Authorized EPIC Budget (Annual)

2012 – 2014 (Jan 1 – Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	\$1.3M[50]	\$11.9M[51]	\$0.33M[52]
CEC Program	\$5.3M[53]	\$47.7M[54]	

(2) 2015 – 2017 Investment Plan

Table 6: 2015 – 2017 Authorized EPIC Budget (Annual)

2015 – 2017 (Jan 1 – Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	\$1.4M[55]	\$12.5M[56]	\$0.07M[57]
CEC Program	\$5.6M[58]	\$50M[59]	\$0.28M[60]

(3) 2018 – 2020 Investment Plan

Table 7: 2018 – 2020 Authorized EPIC Budget (Annual)

2018 – 2020 (Jan 1 – Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	\$1.5M[61]	\$13.6M[62]	\$0.08M[63]
CEC Program	\$6.1M[64]	\$54.4M[65]	\$0.30M[66]

50 D.12-05-037, p. 73 and OP 7. SCE has a 41.1% share of the IOU 2012 – 2014 budget.
51 *Ibid.*
52 *Ibid*. SCE is responsible for collecting 41.1% share of the 2012 – 2014 CPUC Regulatory Oversight budget. This is the portion that SCE collects of behalf of CPUC.
53 *Ibid*. SCE is responsible for collecting 41.1% of CEC's 2012 – 2014 budget.
54 *Ibid*.
55 D.15-04-020, p. 3 – 4 and Appendix B.
56 *Ibid*.
57 *Ibid*.
58 D.15-04-020, p. 3 – 4 and Appendix B. SCE is responsible for collecting 41.1% of CEC's 2015 – 2017 budget.
59 *Ibid*.
60 *Ibid*.
61 D.18-01-008, p. 38 and OP 7.
62 *Ibid.*
63 *Ibid.*
64 *Ibid.* SCE is responsible for collecting 41.1% of CEC's 2018 – 2020 budget (per D.18-01-008, OP 8).
65 *Ibid.*
66 *Ibid.*

(4) 2021 – 2025 Investment Plan

Table 8: 2021 – 2025 Authorized EPIC Budget (Annual)

2021 – 2025 (Jan 1 – Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	$1.5M[67]	$13.6M[68]	$0.08M[69]
CEC Program	$9.8M[70]	$50.7M[71]	$0.30M[72]

Table 9: 2021 – 2025 Authorized EPIC Project Budget by Strategic Initiative (Total 5-year Budget))

Strategic Objectives	Strategic Initiative	Amount
Create a More Nimble Grid to Maintain Reliability as California Transitions to 100% Clean Energy	T&D Foundational Technologies	$10.5M[73]
	T&D Situational Capabilities	$13.3M[74]
Increase the Value Proposition of Distributed Energy Resources to Customers and the Grid	Energy Management Foundational Technologies	$13.0M[75],[76]
	Energy Management Situational Capabilities	$14.2 M[77]
Inform California's Transition to an Equitable, Zero-Carbon Energy System that is Climate-Resilient and Meets Environmental Goals	Vulnerabilities, Threats, and Hazard Reduction	$8.7M[78]
	Digital Transformation	$8.4M[79]
Total		**$68.1M[80]**

---

67 D.21-11-028, Appendix B and OP 3.

68 *Ibid.*

69 *Ibid.*

70 D.21-11-028, Appendix B, OP 3, OP 5 and OP 8. OP 5 Allowed CEC to increase the soft cap on its Administrative Costs from 10% to 15%.

71 *Ibid.*

72 D.21-11-028, Appendix B, OP 3 and OP 8. SCE is responsible for collecting 41.1% of CEC's 2021 – 2025 budget.

73 A.22-10-001.

74 *Ibid.*

75 *Ibid.*

76 During 2025, SCE increased the Budget in Energy Management Situation Capabilities by $1,000,000 and reduced the budget for Energy Management Foundational Technologies by $1,000,000. In both cases, this transfer was below 15% of the budget of either Strategic Initiative, and so, consistent with D. 21-11-028, OP11, which states, "Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company and the California Energy Commission shall file a Tier 2 Advice Letter seeking Commission approval to reallocate more than 15 percent of funds between initiatives," no further filing or reporting was done.

77 *Ibid.*

78 A.22-10-001.

79 *Ibid.*

80 *Ibid.*

b) Commitments/Encumbrances

(1) 2012 – 2014 Investment Plan

As of December 31, 2025, SCE has committed $0 and encumbered $0 of its authorized 2012 – 2014 program budget.

(2) 2015 – 2017 Investment Plan

As of December 31, 2025, SCE has committed $0 and encumbered $289,761 of its authorized 2015 – 2017 program budget.

(3) 2018 – 2020 Investment Plan

As of December 31, 2025, SCE has committed $5,929,898 and encumbered $3,022,792 of its authorized 2018 – 2020 program budget.

(4) 2021 – 2025 Investment Plan

As of December 31, 2025, SCE has committed $61,573,094 and encumbered $2,059,507 of its authorized 2021 – 2025 program budget.

(5) CEC & CPUC Remittances

For CEC remittances, SCE remitted $16,727,700 for program administration, and $88,213,369 for encumbered projects during calendar year 2025.

For CPUC remittances, SCE remitted $380,175 in calendar year 2025.

c) Fund Shifting Above 15% between Strategic Initiatives

As of December 31, 2025, SCE does not have any pending fund shifting requests and/or approvals between Strategic Initiatives for the 2012 – 2014, 2015 – 2017, 2018 – 2020 or 2021 – 2025 investment plans. As noted in Table 9, during 2025, SCE increased the Budget in Energy Management Situation Capabilities by $1,000,000 and reduced the budget for Energy Management Foundational Technologies by $1,000,000. In both cases, this transfer was below 15% of the budget of either Strategic Initiative, and so, consistent with D. 21-11-028, OP11,[81] no further filing or reporting was done.

---

[81] D.21-11-028, OP 11 D. 21-11-028, OP 11, states "Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company and the California Energy Commission shall file a Tier 2 Advice Letter seeking Commission approval to reallocate more than 15 percent of funds between initiatives."

d) Uncommitted/Unencumbered Funds

As of December 31, 2025, SCE has no uncommitted/unencumbered funds for the 2012 – 2014, 2015 – 2017, 2018 – 2020, or 2021 – 2025 investment plans.

4. Projects

a) High Level Summary

SCE provides a summary of project funding for SCE's 2012 – 2014, 2015 – 2017, 2018 – 2020 and 2021 – 2025 Investment Plans; please refer to Table 10, Table 12, Table 14, and Table 16, respectively. In accordance with the Commission's directives,[82] SCE has prepared Final Project Reports for each completed project and included them in the Annual Reports according to the years completed.

(1) 2012 – 2014 Investment Plan

As of December 31, 2025, SCE has expended $38,642,227 on program costs. No projects from the 2012 – 2014 Investment Plan remain in execution as of December 31, 2025. Table 10 summarizes the 2012 – 2014 Investment Plan projects by program category and completion year.

Table 10: 2012 – 2014 Investment Plan Summary

1. Energy Resources Integration

Three projects funded
• Completed in 2016: Distribution Planning Tool
• Completed in 2018:
  • Distributed Optimized Storage (DOS) Protection & Control Demonstration and
  • Advanced Voltage and VAR Control of SCE Transmission Project

2. Grid Modernization and Optimization
Five projects funded • Cancelled in 2014: Superconducting Transformer[83] • Completed in 2015: Portable End-to-End Test System • Completed in 2016: Dynamic Line Rating • Completed in 2017: Next Generation Distribution Automation, Phase 1 • Completed in 2020: Substation Automation 3 (SA-3), Phase 1
3. Customer Focused Products and Services
Three projects funded • Completed in 2015: Outage Management and Customer Voltage Data Analytics Demonstration

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

[83] SCE cancelled the Superconducting Transformer project in Q2, 2014. Please refer to the project's status update in Section 4 for additional details.

• Completed in 2016: Submetering Enablement Demonstration • Completed in 2017: Beyond the Meter: Customer Device Communications Unification and Demonstration
4. Cross-Cutting/Foundational Strategies and Technologies

Five projects funded
• Completed in 2015: Cyber-Intrusion Auto-Response and Policy Management System
• Completed in 2016: Enhanced Infrastructure Technology Report
• Completed in 2017:
  • State Estimation Using Phasor Measurement Technologies Project
  • Deep Grid Coordination Project (otherwise known as the Integrated Grid Project)
• Completed in 2019: Wide Area Management and Control

Total Projects Funded: 16 Total Authorized Project Budget: $37,656,998[84] Total Project Spend: $37,087,185[85] Total Funding Committed: 0 Total Encumbered: 0 *Note: Due to intrinsic variability in TD&D projects, amounts shown are subject to change*

Table 11 below summarizes SCE's administrative expenses for the 2012 – 2014 investment plan:

Table 11: 2012 – 2014 Investment Plan Administration Expenses

Total Authorized Budget:	$1,855,002[86]
Total Cumulative Cost:	$1,555,042 [87]
Total 2025 Cost:	$0

(2) 2015 – 2017 Investment Plan

As of December 31, 2025, SCE has expended $40,559,807 [88] on program costs. Table 12 below summarizes the current status of SCE's EPIC 2 projects:

[84] D.12-05-037, as updated by D.13-11-025. Includes $2,045,000 transfer from administrative funds to project funds.

[85] SCE returned $569,813 of Project funds and $299,599 in Administrative funds to ratepayers in AL 5779-E.

[86] 2012-2014 EPIC I Administrative Budget is $3,812,000. SCE Program Management transferred $1,956,998 from the Administrative to the Project Budget, reducing the Authorized Budget to $1,855,002.

[87] SCE returned $569,813 of Project funds and $299,599 in Administrative funds to ratepayers in AL 5779-E.

[88] SCE's cumulative project expenses amounted to $37,031,989. SCE's cumulative administration expenses amounted to $3,527,818. These totals include SCE labor and overheads. As a result, SCE expended a total of $40,559,807 on program costs.

Table 12: 2015 – 2017 Investment Plan Summary

1. Energy Resources Integration

Three projects funded
• Cancelled in 2016:
  • Bulk System Restoration under High Renewables Penetration project
  • Series Compensation for Load Flow Control project
• Cancelled in 2017: Optimized Control of Multiple Storage Systems

2. Grid Modernization and Optimization
Six projects funded • Completed in 2017: Advanced Grid Capabilities Using Smart Meter Data • Completed in 2018: Proactive Storm Impact Analysis Demonstration • Completed in 2019: Versatile Plug-in Auxiliary Power System • Completed in 2020: Dynamic Power Conditioner • Completed in 2022: Next-Generation Distribution Equipment & Automation, Phase 2 • Currently In Execution: System Intelligence and Situational Awareness Capabilities
3. Customer Focused Products and Services

Three projects funded
• Completed in 2018:
  • DC Fast Charging
  • Integration of Big Data for Advanced Automated Customer Load Management
• Completed in 2019: Regulatory Mandates: Submetering Enablement Demonstration, Phase 2

4. Cross-Cutting/Foundational Strategies and Technologies
One project funded • Completed in 2021: Integrated Grid Project II
Total Projects Funded: 13 Total Authorized Project Budget: $37,504,200[89] Total Project Spend: $37,031,990 Total Funding Committed: $182,449 Total Encumbered: $289,761 *Note: Due to intrinsic variability in TD&D projects, amounts shown are subject to change*

Table 13 below summarizes SCE's administrative expenses for the 2015 – 2017 investment plan:

Table 13: 2015 – 2017 Investment Plan Administration Expenses

Total Authorized Budget:	$4,190,400[90]
Total Cumulative Cost:	$3,527,818
Total 2025 Cost:	$171,044

[89] D.15-04-020, Ordering Paragraph 1 - Appendix B, Table-5, p. 7.
[90] *Ibid.*

(3) 2018 – 2020 Investment Plan

As of December 31, 2025, SCE has expended $32,757,919[91] on program costs. Table 14 below summarizes the current status of SCE's EPIC 3 projects.

Table 14: 2018 – 2020 Investment Plan Summary

1. Energy Resources Integration
Two projects funded • Completed in 2023: Distributed Energy Resources Dynamics Integration Demonstration • Currently in Execution: Smart City Demonstration
2. Grid Modernization and Optimization

Six projects funded
• Cancelled in 2020: Power System Voltage and VAR Control Under High Renewables Penetration
• Hold/Deferred in 2020: Distribution Primary & Secondary Line Impedance Project
• Currently in Execution:
  ◦ Beyond Lithium-ion Energy Storage Demo
  ◦ SA-3, Phase III Field Demonstrations
  ◦ Storage-Based Distribution DC Link
  ◦ Next Generation Distribution Automation III project

3. Customer Focused Products and Services

Four projects funded
• Completed in 2025:
  ◦ Control and Protection for Microgrids and Virtual Power Plants
  ◦ Distributed Plug-In EV Charging Resource
• Currently in Execution:
  ◦ Service and Distribution Centers of the Future; and
  ◦ Vehicle-to-Grid Integration Using On-Board Inverter

4. Cross-Cutting/Foundational Strategies and Technologies

Seven projects funded
• Cancelled in 2019: Energy System Cybersecurity Posturing
• Hold/Deferred in 2021: Advanced Data Analytics Technologies (ADAT)
• Completed in 2021: Distributed Cyber Threat Analysis Collaboration (DCTAC)
• Completed in 2022: Cybersecurity for Industrial Control Systems
• Completed in 2024: Advanced Comprehensive Hazards Tool
• Currently in Execution:
  ◦ Advanced Technology for Field Safety (ATFS); and
  ◦ Wildfire Prevention & Resiliency Technology Demonstration

Total Projects Funded: 19

[91] SCE's cumulative project expenses amounted to $28,620,504. SCE's cumulative administration expenses amounted to $4,137,416. These totals include SCE labor and overheads. As a result, SCE expended a total of $32,757,919, on program costs.

Total Authorized Project Budget: $40,830,795[92] Total Project Spend: $28,620,504 Total Funding Committed: $9,187,499 Total Encumbered: $3,022,792 *Due to intrinsic variability in TD&D projects, amounts shown are subject to change*

Table 15 below summarizes SCE's administrative expenses for the 2018 – 2020 investment plan:

Table 15: 2018 – 2020 Investment Plan Administration Expenses

Total Authorized Budget:	$4,562,100[93]
Total Cumulative Cost:	$4,137,416
Total 2025 Cost:	$168,016

(4) 2021 – 2025 Investment Plan

As of December 31, 2025, SCE has expended $5,108,080[94] on program costs. Table 16 below summarizes the current status and funding of SCE's EPIC 4 projects.

Table 16: 2021 – 2025 Investment Plan Summary

1. T&D Foundational Technologies	**Total Initiative Funding**

Two projects funded
• Currently in Execution:
  • Quantum Networking
  • Communication Assisted Protection Technologies for Inverter-based Networks (CAPTIN)
	$10,500,000[95]

2. T&D Situational Capabilities	**Total Initiative Funding**

Two projects funded
• Currently in Execution:
  • Flexible Alternating Current System (FACS)
  • Thermally Optimized Advanced Duct Strategy (TOADS)
	$13,300,000[96]

3. Energy Management Foundational Technologies	**Total Initiative Funding**

92 D.18-01-008, at p. 38.

93 D.18-01-008, at p. 38.

94 SCE's cumulative project expenses amounted to $4,418,724. SCE's cumulative administration expenses amounted to $689,356. These totals include SCE labor and overheads. As a result, SCE expended a total of $5,108,080 on program costs.

95 A.22-10-001.

96 *Ibid.*

Two projects funded
• Currently in Execution:
  • Stability Improvement with DERs (SIDER)
  • Industrial Demand Flexibility Enabling Distribution Grid Autonomous Resilience (IDF-EDGAR)
	$13,000,000[97],[98]

4. Energy Management Situational Capabilities	**Total Initiative Funding**

Two projects funded
• Currently in Execution:
  • Swift Electrification of Transit (SET)
  • Local Optimization & Grid Edge Management Systems (LO-GEMS)
	$14,200,000[99],[100]

5. Vulnerabilities, Threats, and Hazard Reduction	**Total Initiative Funding**
One project funded • Currently in Execution: A2G Operational Efficiencies	$8,651,325[101]
6. Digital Transformation	**Total Initiative Funding**
One project funded • Currently in Execution: ML-Augmented Digital Simulation (MAD-S)	$8,400,000[102]
Total Projects Funded: 10 Total Authorized Project Budget: $68,051,325[103] Total Project Spend: $4,418,724 Total Funding Committed: $ 61,573,094 Total Encumbered: $2,059,507 *Due to intrinsic variability in TD&D projects, amounts shown are subject to change*	

97 *Ibid.*

98 During 2025, SCE increased the Budget in Energy Management Situation Capabilities by $1,000,000 and reduced the budget for Energy Management Foundational Technologies by $1,000,000. In both cases, this transfer was below 15% of the budget of either Strategic Initiative, and so, consistent with D. 21-11-028, OP11, which states, "Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company and the California Energy Commission shall file a Tier 2 Advice Letter seeking Commission approval to reallocate more than 15 percent of funds between initiatives," no further filing or reporting was done.

99 A.22-10-001.

100 During 2025, SCE increased the Budget in Energy Management Situation Capabilities by $1,000,000 and reduced the budget for Energy Management Foundational Technologies by $1,000,000. In both cases, this transfer was below 15% of the budget of either Strategic Initiative, and so, consistent with D. 21-11-028, OP11, which states, "Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company and the California Energy Commission shall file a Tier 2 Advice Letter seeking Commission approval to reallocate more than 15 percent of funds between initiatives," no further filing or reporting was done..

101 A.22-10-001.

102 *Ibid.*

103 D.21-11-028, Appendix B Table 3, at p. B3.

Table 17 below summarizes SCE's administrative expenses for the 2021 – 2025 investment plan:

Table 17: 2021 – 2025 Investment Plan Administration Expenses

Total Authorized Budget:	$7,605,500[104]
Total Cumulative Cost:	$689,356
Total 2025 Cost:	$597,649

b) Project Status Report

The descriptions of the project objectives and scope reflect the proposals filed in the respective EPIC Investment Plans,[105] while the project status information reflects the progress of active projects through 2025.

(1) 2015 – 2017 Investment Plan Projects

1. System Intelligence and Situational Awareness Capabilities

Investment Plan Period	**Assignment to Value Chain**
2nd Triennial Plan (2015 – 2017)	Distribution
Objective & Scope System Intelligence and Situational Awareness Capabilities (SISA) will demonstrate system intelligence and situational awareness capabilities such as high impedance fault detection, intelligent alarming, predictive maintenance, and automated testing. This multi-phase project aims to help SCE transition from traditional substations that rely heavily on copper wiring to digital substations that use standardized communications and software-based intelligence. The project does this by validating IEC 61850-based technologies, addressing remaining testing and system-integration challenges, and establishing consistent, repeatable practices for engineering, commissioning, and field testing. This objective is important to SCE because it enables a tested and verified transition to digital substations that support grid modernization, renewable integration, and evolving cybersecurity needs. By validating IEC 61850 technologies and establishing repeatable testing and commissioning practices, the project reduces deployment uncertainty. For ratepayers, this delivers improved reliability through faster fault detection and adaptive protection, enhanced safety by reducing energized copper wiring and manual field work, and greater affordability through simpler construction, shorter commissioning timelines, and lower lifecycle costs—positioning SCE to modernize the grid more efficiently in support of California's clean energy goals.	

104 *Ibid.*

105 The EPIC 1 Investment Plan Application (A.)12-11-004 was filed on November 1, 2012. The EPIC 2 Investment Plan A.14-05-005 was filed on May 1, 2014. The EPIC 3 Investment Plan A.17-05-005 on May 1, 2017. The EPIC 4 Investment Plan A.22-10-001 on October 3, 2022.

By progressively moving from automated test tools to live field demonstrations and full digital substation lab implementations, the project:

- Reduces technical, operational, and safety risk associated with deploying process bus and digital protection systems.
- Provides concrete evidence to support or reject widescale adoption decisions, rather than relying on vendor claims or isolated pilots.
- Shortens future design and commissioning timelines through automation, standardization, and higher test coverage.
- Improves field worker safety by minimizing energized copper wiring and manual testing.
- Positions SCE to modernize its grid faster and at lower life-cycle cost while supporting renewables, inverter-based resources, and evolving cybersecurity requirements.

Ultimately, this project transforms digital substations from an experimental concept into a deployable SCE capability—ensuring future grid investments are safer, more resilient, and economically viable.

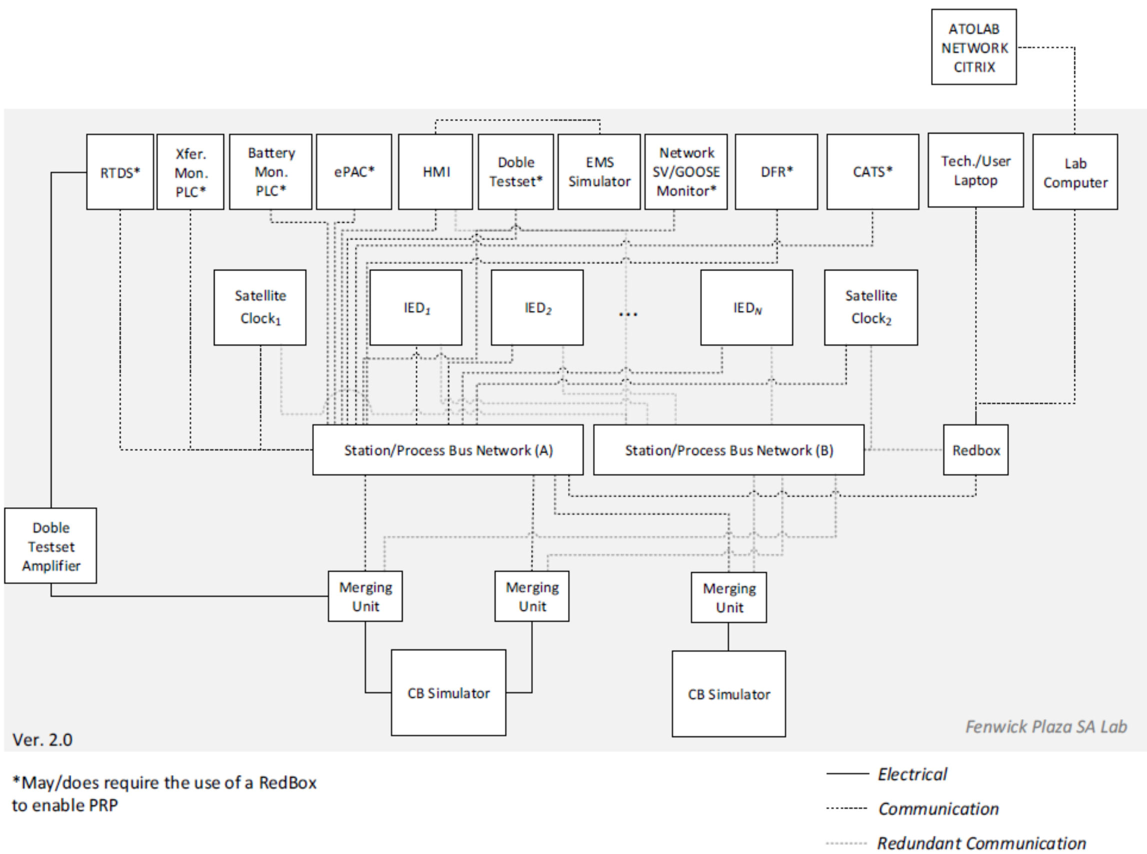
The project integrates intelligent algorithms and advanced applications with the latest substation automation technologies, next generation control systems, latest breakthrough in substation equipment, sensing technology, and communications assisted protection schemes. This system will leverage the International 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 North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP) compliance requirements. Lab Demonstration of Fully Digital Substation (Parkwood B Station) test end-to-end digital capabilities between various simulated switchyard gear and protection and control (P&C) devices via a digital interface using IEC 61850 process bus technology.

The process bus technology is a key enabler to the digital substation, which will enable SCE to substitute engineering-intensive and costly point-to-point copper signaling wires with a safe, standardized optical communication bus (i.e., process bus). In doing so, SCE will remove the copper connections between its high-voltage switchgear and the various P&C devices needed to operate the substation. By retrofitting an existing distribution substation with IEC 61850 process bus technology and replacing protection relays with IEC 61850-capable Intelligent Electronic Devices (IEDs), SCE can develop a more flexible and cost-effective foundation for protecting substations amid increasing renewables and security standards. More specifically, the team anticipates the following potential benefits for its business stakeholders:

- Replacing complex point-to-point copper wires with safe, standardized optical communications will help reduce capital costs associated with the required footprint, construction, and testing of P&C systems.
- An IEC 61850 standard process bus makes it easier to update P&C applications and schemes by updating software configurations rather than hardwired reconfigurations, thereby reducing

outage time and maintenance costs (O&M), and providing quicker responses to new protection challenges.

- Potential improvement to field worker safety due to the elimination of electrical connections between high-voltage switchgear and P&C devices—e.g., reducing the potential for inadvertently-opened Current Transformer (CT) circuits.
- The process bus will help increase SCE's understanding of what is occurring within the substation by enabling remote and on-site real-time system monitoring capabilities.
- Data and analysis from devices also enable near real-time asset monitoring, predictive analytics, and health indices to support "just-in-time" asset replacement, increasing the useful lives of capital assets.
- An IEC 61850 standard process bus enables interoperability between devices made by different manufacturers, allowing SCE to choose best-in-breed P&C devices and/or virtual applications.
- Context diagram:



Schedule

Q2 2016 – Q2 2026

Project History

The latest phase of the project, Fully Digital Substation (FDS), reflects a phased series of activities executed by SCE within the SISA project to advance digital substation capabilities. Rather than pursuing a single demonstration, SCE intentionally followed a risk-managed progression - from testing tools and lab evaluations to targeted field demonstrations, and ultimately to an integrated, end-to-end digital substation architecture. Across multiple phases, the shared objective has been to determine when, where, and how IEC 61850-based digital substations can be safely, reliably, and economically deployed on the SCE system.

The early phases focused on establishing testing and commissioning readiness by developing automated IEC 61850 simulation and test tools, demonstrating that traditional manual testing methods do not scale for digital substations.

A key effort earlier in the project was completion of the Proof of Concept, as described in the 2022 EPIC Annual Report, of IEC 61850-capable relays and other Intelligent Electronic Devices (IED), merging units (MU), and associated process bus hardware (HW) and software (SW) components. The purpose of the proof-of-concept project was to demonstrate the benefits and functionality of using digital technology in a lab environment, while working toward the long-term goal of implementing a complete IEC 61850 substation automation system. These capabilities enabled subsequent projects by providing the testing backbone used in later lab and field evaluations.

This enabled subsequent field-based validation with the Mayberry process bus field demonstration, which validated safe and reliable operation of IEC 61850 process bus and fiber-optic current transformers under real fault conditions, while intentionally limiting scope to manage operational risk.

Following these outcomes, broader technology evaluations were conducted consolidating internal and industry experience into a formal technology assessment, concluding that while process bus showed strong potential, further system-level validation was needed before standardization. This supported a laboratory-based proof of concept, where SCE evaluated a complete multi-vendor digital substation in a lab environment, identifying integration challenges, interoperability gaps, and requirements for standards, training, and time synchronization.

The current phase, FDS, represents the most mature stage of the program. It validated an end-to-end digital substation architecture through rigorous testing, including Real-Time Digital Simulator (RTDS) hardware-in-the-loop, cybersecurity monitoring, network stress testing, and advanced protection evaluation. While comprehensive, this phase intentionally remains a lab deployment, reflecting SCE's stepwise approach to balancing innovation with system reliability. Together, these projects establish a strong technical and organizational foundation for future digital substation deployments and position SCE to pursue next-phase efforts focused on field scaling, standardization, and maximizing ratepayer value.

During the past year, the project successfully completed laboratory testing, demonstrations, and detailed analysis of results, meeting the core objectives of validating a fully digital substation architecture. Achieving these objectives provided SCE and the SISA project with practical, system-level evidence that IEC 61850 process bus and digital protection technologies can be engineered, tested, and integrated in a repeatable and reliable manner. This work moved SCE

beyond conceptual evaluation to a state of technical readiness, enabling lessons learned to be carried forward into future designs, standards development, and deployment planning.
For SCE, these outcomes establish a clear pathway to apply process bus technology in future compact substation initiatives and other targeted deployments, reducing uncertainty around integration, testing, cybersecurity, and operational performance. For ratepayers, this translates into long-term benefits through improved reliability from more advanced monitoring and protection, enhanced safety by reducing energized copper wiring and manual field work, and greater affordability through standardized designs, shorter commissioning timelines, and lower lifecycle costs.

Looking ahead, the Team will leverage IEC 61850-capable protection relays to replace the conventional relays. The new relays will be configured using vendor configuration tools that align to the IEC 61850 standard, enabling interoperability amongst the various vendor IEDs and process bus. The new IEC 61850-capable relays will receive digital monitoring inputs in the form of Sampled Measured Value (SMV) via the process bus, which they will use to compute all SCE required protection functions (e.g., instantaneous overcurrent, time overcurrent) and will transmit binary Generic Object Oriented Substation Event (GOOSE) messages to the appropriate IED for status and control commands.

2025 Status Update

Accomplishments & Success Stories

- The system is designed based on a standard SCE 66/12kV distribution substation arrangement, incorporating 26 protection relays and 33 merging units.
- In the beginning of the year, SCE completed the lab equipment installation. Immediately after, SCE finalized set up of the IT environment while ensuring appropriate configuration of the network and servers.
- Once the setup was complete, SCE conducted a thorough cyber risk assessment on all network-connected devices.
- Finally, SCE performed extensive testing to validate protection and automation schemes, network performance, and PTP time synchronization. These assessments included unit/interface tests, scheme tests, network performance tests, PTP tests, and RTDS tests. All completed work will support the technology transfer process, as well as contribute to the final report that captures overall test findings, lessons learned, and recommendations.

Challenges or Setbacks

- The team did not identify additional challenges or setbacks.

Key Findings and Lessons Learned

- The testing confirmed that fully digital substations using IEC 61850 technology are viable for deployment in live substations. The protection and automation schemes operated as expected with minimal issues.
- Different firmware versions can significantly impact performance and interoperability. Thorough pre-deployment testing is crucial, and a pre-defined firmware update process should be implemented to mitigate risks associated with new firmware releases.

- Digital substations are easy to scale and repeat. To keep them consistent and avoid setup issues, it is best to use standard templates instead of custom configurations.
- Time synchronization should be treated as protection infrastructure, not just a communications or IT concern, and must be engineered with redundancy, monitoring, and explicit failure behavior.

<u>Customer Benefits</u>

SISA delivers direct benefits to SCE customers by improving the safety, reliability, and affordability of electric service.

- Potential improvement to field worker safety due to the elimination of electrical connections between high-voltage switchgear and P&C device - e.g., reducing the potential for inadvertently-opened Current Transformer (CT) circuits. By eliminating electrical connections between high-voltage switchgear and protection and control devices, the project reduces safety risks for field workers, which in turn lowers the likelihood of service disruptions caused by equipment damage or human error.
- The process bus will help increase SCE’s understanding of what is occurring within the substation by enabling remote and on-site real-time system monitoring capabilities. Data and analysis from devices also enable near real-time asset monitoring, predictive analytics, and health indices to support “just-in-time” asset replacement, increasing the useful lives of capital assets. Enhanced real-time monitoring and situational awareness improve SCE’s ability to detect abnormal conditions early, respond to issues more quickly, and restore service faster when outages occur. Near real-time asset monitoring and predictive analytics support just-in-time maintenance and replacement, helping avoid unplanned failures and extending the life of critical infrastructure— lower long-term cost impacts for customers.
- This project will also increase SCE’s ability to meet security and NERC CIP compliance requirements. Implementing IEC 61850 process bus technology and IEC 61850-capable Intelligent Electronic Devices (IEDs) will provide SCE more flexible and cost-effective foundation for protecting substations amid increasing renewables and security standards. Elimination of electrical connections between high-voltage switchgear and protection devices improves worker safety. In addition, improved cybersecurity and compliance capabilities help protect customers from the reliability and financial impacts of cyber incidents, while providing a flexible and cost-effective foundation to support increasing renewable generation and evolving grid security requirements.

<u>Anticipated RFPs</u>

- There are no anticipated RFPs.

<u>Industry Advancement</u>

- Upon successful completion of the Fully Digital Substation project, the process bus technology will be leveraged in future SCE compact sub initiatives.
- Vendors were able to build new firmware that fixed the issues discovered during lab demonstration testing.

• SCE shared project findings through EPIC stakeholder workshops, utility and vendor technical forums, and industry conferences, including presentations on the Mayberry field demonstration, process bus readiness, and SP3/SP4 lab results. Engagements with groups such as the Process Bus User Task Force, utility peer exchanges, vendor interoperability sessions, and IEEE-aligned forums helped incorporate lessons learned, particularly on testing, time synchronization, interoperability, and phased deployment, into broader industry dialogue. • The project had a direct impact on vendor product development. Multi-vendor system-level testing conducted during the integrated lab demonstration phases led to firmware updates addressing time synchronization (SmpSynch) handling, protection behavior under degraded time synchronization, and SV subscription limitations. Several vendors are also committed to enhanced IEC 61869-9 support, improved diagnostics, and greater configurability—often citing SCE test results as justification for accelerating roadmap changes. These outcomes moved vendor offerings closer to utility-grade, interoperable solutions.

(2) 2018 – 2020 Investment Plan Projects

1. Advanced Data Analytics Technologies

Investment Plan Period 3rd Triennial Plan (2018 – 2020)	**Assignment to Value Chain** Grid Operation/Market Design
Objective & Scope This project will demonstrate the possibility of using advanced data analytics technologies for Transmission and Distribution (T&D) and customer maintenance. This project will evaluate pattern recognition technologies that are capable of using new and/or existing data sources such as from sensors, smart meters, and supervisory control and data acquisition (SCADA), for predicting or providing alarms on the incipient failure of distribution system assets. These assets would include connectors, transformers, cables, and smart meters. Use-case Scope Use supervised machine learning techniques to train, validate, then demonstrate a time-to-failure model on a subset of SCE's distribution transformer installed base. The models will quantify the probability of failure (at the transformer-level) and estimate the remaining useful life (RUL) of distribution transformers. Business Objective 1. Inputs to the Transformer Asset Class Strategies a. Inform risk buy down calculations based on remaining useful life (RUL) b. Inform aggregation of like transformers based on level of RUL for decision making. 2. Prevent an In-service Failure a. Avoid unplanned outage time (reduced CMI, reduce crew OT expense) b. Repair during planned outage (lessen customer impact) c. Avoid catastrophic failure and resulting consequences (damage to customer/public property, safety, surrounding equipment, wildfire ignition)	

3. Procurement/Inventory Planning a. Pre-order replacement transformer if there are none in inventory. b. Budget planning for future procurement (Inform future GRC Testimony)
2025 Status Update • This project was deferred in April 2021 to allow consideration of other projects which may offer greater benefits aligned with California and CPUC objectives. • In 2025, SCE cancelled the project.

2. Advanced Technology for Field Safety

Investment Plan Period 3rd Triennial Plan (2018 – 2020)	**Assignment to Value Chain** Distribution
Objective & Scope The Advanced Technology for Field Safety (ATFS) project will introduce an integrated system that consists of an AR (Augmented Reality) wearable, handheld device, a communication module, machine vision, generative AI, and a digital twin of an underground (UG) vault. The objective is to address the risks posed from grid assets and the environment to the workforce and to enhance the efficiency of the individuals' workflow by introducing an innovative solution that enables them to overcome the challenges they may face in their daily jobs. Specific benefits will include: • Smart asset management because of increased visibility of UG assets during work order planning. • Enhancing field worker efficiency by using an AR handheld device with computer vision to automatically generate asset record correction notifications and submit the requests directly into the SAP Enterprise Resource Planning system, minimizing human error. • Lowering costs by utilizing the as-is digital twin of the underground vault, reducing the need for multiple site visits. • Helping maintain an up-to-date digital twin of UG vault assets through automatic object recognition. The identified challenges and workforce concerns that motivated launch of this proof-of-concept project include: • **Outdated UG structure Inventory:** Currently, any information that is captured at the site during structure inventory collection initiatives for specific teams is not accessible and maintained for any future use of similar types of projects. There is no unified platform representing the UG system accessible to all stakeholders and for various applications. • **Inefficient field data management:** The existing manual data collection method has a high probability of human errors (e.g., typos) or data loss due to hardcopy paperwork. There is room for innovation to demonstrate tools to efficiently verify SCE internal records as opposed to what they see in the field. Collected data and information is archived after a job is done and is not maintained or kept up to date for later usage. • **Limited access to backend data:** Workforce needs to go through a lot of paperwork/	

hardcopies and time-consuming steps to access diverse types of information pertaining to any asset/equipment. Sometimes all necessary documents might not be collected before visiting the field which may cause delays in the process.

The scope of the project includes:

- Utilizing innovative technologies (e.g., machine vision) to collect data to eliminate human error. The captured information would be verified against the backend datasets/digital twin to ensure data accuracy and integrity.
- UG equipment inventory collection will be achieved by camera/sensors on the AR system with GPS mapping/point cloud features to display the location and layout of underground structures. The Team will collect and update the inventory automatically using 3D camera and machine vision. This process will help to maintain an up-to-date digital twin of the UG vault.
- The 3D digital twin would have detailed information about individual components, such as equipment 3D model, specifications, geographic location, maintenance history, Supervisory Control and Data Acquisition (SCADA) points, direction of the vault, elbow configurations, switching positions, cable size, nameplates and device IDs of the assets, and a scale to measure clearance distances. This eliminates the need to go through multiple site visits before the job and time-consuming steps to access different layers of information pertaining to any asset/equipment.
- The project will also facilitate live remote assistance between field crews, planners, and Foremen. Using AR-enabled devices, crews in the field can establish a live video feed, allowing remote experts to view the equipment and provide real-time guidance and support. The Team is looking to work on interactive access to standards, manuals, and provide voice-enabled assistance by leveraging generative AI technology and Large Language Models.

Schedule

Q1 2022 – Q1 2028

Project History

The project was re-initiated in 2022 with the intent to improve situational awareness inside a UG vault. The project developed a prototype UG Digital Twin in Q1 2025 and gathered initial learnings regarding feasibility of hardware (Augmented Reality Headset) options, as detailed in the 2024 Annual Report.

As mentioned in the 2024 Annual Report, the project launched an RFI (Request for Information) and RFP (Request for Proposal) in 2024 and 2025, respectively. The RFP was answered by 4 vendors with a single clear winner; however, delays occurred due to extended contract negotiations and concerns with standard Purchase Order (PO) Terms and Conditions (T&Cs). The vendor's request for a new Masters Services Agreement (MSA) with additional terms required engagement from Supply Management and Legal.

The project's 1-to-1 scale Augmented Reality solution will integrate with a static (descriptive) Digital Twin of the selected de-energized underground vault, hosting as-is asset data only. Operational (two-way) Digital Twin capabilities are out of scope for this project and are being

addressed under separate SCE initiatives, such as the EPIC 4 project, Machine-Learning Augmented Digital Simulation (MAD-S). While the scopes do not overlap, the projects are complementary and mutually reinforcing. The deliverables of this ATFS project align with SCE's overall Digital Twin strategy.
2025 Status Update Accomplishments & Success Stories • The project team completed market research and feasibility assessments of available AR hardware options, which included building a prototype underground vault digital twin and collecting user feedback regarding AR devices from multiple vendors. • Following hands-on evaluation of products from multiple vendors, the project team selected an AR device for implementation. • An abstract paper has been presented as a poster to the IEEE Digital Twin and Parallel Intelligence conference in Q2 2025 to highlight the effort and to showcase the completed prototype project. • Building off of this initial research and findings, the team launched an RFP and downselected to a single technically and commercially favored vendor in Q2 2025. • The PO has been issued to the selected vendor, and the project kick-off meeting was held in Q1 2026. • The team has been in coordination with the broader SCE Digital Twin initiative and is incorporating technical requirements for compatibility (i.e., the use of Omniverse) into the Scope of work for the vendor to implement into software. Challenges or Setbacks • The project team initially selected an AR device and successfully completed a prototype project using it. However, the vendor has discontinued production of the device. The team also studied an AR device from another vendor but found this device to be cumbersome for users. • The team faced substantial challenges in entering into a contractual arrangement with the selected vendor after a successful RFP. This was due in part to the vendor's concerns regarding the standard PO T&Cs in addition to the subsequent need to renegotiate an MSA. Key Findings and Lessons Learned • Because the MSA covers multiple projects, it cannot be simplified based on the ATFS project's low-risk profile and must follow the full MSA T&Cs. • Due to the vendor's acquisition by a larger entity, and to avoid further schedule delays from prolonged MSA negotiations, SCE agreed to proceed under an existing legacy MSA while the new MSA is being finalized. • The project team is exploring the alignment of the final delivery to be compatible with the broader SCE digital twin platform. Customer Benefits • Successful implementation of this project, if scaled to pilot, will eliminate the need for multiple site visits prior to the work order, as planners will have access to the as-is digital

twin of the vault to prepare the work order. This will in turn reduce (not eliminate) the costs associated with multiple vault visits.

- Maintaining an up-to-date digital twin inventory of the UG structure, which includes asset information, SAP, and SCADA points, will result in efficient data management, thus increasing operational efficiency.

Anticipated RFPs

- The RFP process was undertaken in early 2025 and concluded in February 2026. The activities and deliverables for the associated scope include suggesting hardware, digital twin software application development, asset management application development, Job Aid Search Software, Software Solution Testing, hardware integration, Training for the software and hardware, and field testing.

Industry Advancement:

- The team lead presented the prototype project at SCE internal lab tours to internal stakeholders and presented at IEEE Digital Twin and Parallel Intelligence conference on Q2 2025.
- This demonstration approach will provide the industry and stakeholders with greater insight into the new technologies being implemented within SCE and illustrate how the overall energy sector can benefit from these advancements.

3. Beyond Lithium-ion Energy Storage Demonstration

Investment Plan Period	**Assignment to Value Chain**
3rd Triennial Plan (2018 – 2020)	Distribution

Objective & Scope

The objective of the Beyond Lithium-ion Energy Storage Demonstration project is to demonstrate a next-generation, pre-commercial, “beyond lithium-ion” energy storage technology that has a high probability of commercial viability but requires real world field experience to reduce technology and adoption barriers on the path to commercialization.

Lithium-ion based energy storage technologies are generally considered to be mature and are currently the technology of choice for most grid energy storage use cases. However, to achieve California’s ambitious long-term energy policy goals, and SCE’s own Clean Power and Electrification Pathway 2045, the marketplace will require a diversity of cost-competitive energy storage products.

A number of non-lithium energy storage technologies are currently being advertised as having advantages when compared to lithium-ion energy storage technologies (e.g. not as susceptible to thermal runaway, consisting of materials more readily available than lithium, more cost effective for longer duration installations, etc.) but they aren’t able to gain widespread adoption due to the high risk of deploying first-of-a kind technologies.

This project will help to advance the industry's knowledge-base of non-lithium-ion energy storage (NoLESS) technologies to ensure new storage products can "cross the chasm" and compete with traditional storage technologies in the near-future.
Schedule Q3 2020 – Q2 2026
Project History SCE has a long history of testing novel energy storage technologies for grid use. In the early 2000's, SCE cycled lithium-ion based electric vehicle batteries using grid use case profiles to validate their ability to address grid use cases. SCE then performed cycle life testing on various lithium-ion energy storage technologies to gain an understanding of the technology's capabilities and validate their longevity if they were used for grid use cases. Due to SCE's extensive experience in lithium-ion energy storage technologies, SCE was more willing to deploy lithium-ion energy storage systems once they became commercially available, even though the major manufacturers at the time didn't offer the same robust warranties and availability guarantees that they offer today. SCE engineers also worked closely with the manufacturers and integrators to maximize the chances of success. This resulted in SCE's first lithium-ion based grid energy storage systems to have less issues and last longer when compared to that of other lithium-ion based energy storage systems that were deployed at around the time. Today, lithium-ion based energy storage is common throughout SCE's service territory. SCE has gained a lot of experience deploying, operating, and maintaining lithium-ion energy storage systems. But SCE does not have much experience deploying the newer novel technologies that it knows are crucial to meeting the state and company's climate reduction goals. Gaining experience with these novel technologies now will be essential to ensuring that SCE is ready to deploy them once they are commercially available. Going through the process of deploying, operating, maintaining, and decommissioning even a smaller demonstration-grade system will inform SCE and the industry of any significant differences between owning and operating this new technology when compared to traditional lithium-ion energy storage technology. This will result in increased chances for successful and more reliable deployments should the company deploy these technologies in the future.
2025 Status Update <u>Accomplishments & Success Stories</u> • SCE successfully procured, integrated, installed, and tested a 60 kW / 120 kWh third generation Single String Test Article. The testing evaluated the test article's round-trip efficiency at P/2, P4, and P/12 power levels, as well as its ability to perform a frequency regulation profile. The test article was also evaluated for functionality, safety, and performance. During testing, several issues with the energy storage vessel balancing process as well as state of charge calculations were identified, documented, and communicated to the vendor to ensure that they are addressed in future generations of their technology. • Testing was completed in December of 2025, and a vendor to decommission and recycle the system has been identified and engaged.

Challenges or Setbacks

- The project faced significant hurdles procuring test articles. Because the purpose of the project was to acquire and test pre-commercial technologies, a traditional RFP procurement process was not possible. SCE engaged multiple vendors, and some of the technologies could not "scale down" to sizes that would be practical for small demonstrations. Other vendors that could provide scaled down versions appropriate for small demonstrations were hesitant to provide a test article due to the technology flowdown requirements in the EPIC terms and conditions.
- There were also significant hurdles in enacting Non-Disclosure Agreements and Trial Use Agreements, with the legal teams from SCE and the engaged vendors spending up to years negotiating terms and conditions. Again, supplier concerns with EPIC flowdown terms and conditions were a significant challenge.
- Due to the novel nature of the technology, only a single recycling company had experience recycling the vendor's technology. SCE had never worked with that particular recycling company, so it had to spend months vetting the company to ensure that it fulfilled certain guidelines and disposed of the material properly. Additional vendors capable of recycling the technology will most likely increase as the technology is adopted.

Key Findings and Lessons Learned

- The testing confirmed that the vendor's Nickel Hydrogen energy storage technology delivers relatively high operational stability with efficiencies comparable to leading Lithium-Ion energy storage technologies.
- The battery management system could be improved, as in some rare instances, the state of charge calculation abruptly jumped from one value to another (e.g., from 86% State of Charge (SOC) to 100% SOC during a C/12 charge, and from 91% SOC to 100% SOC during a C/4 charge).
- The energy storage vessel voltages were also found to diverge relatively quickly during long periods of idle time, requiring the end-users to perform cell balancing charges before operating the system further. Lithium-Ion based energy storage systems do occasionally have to be balanced, but the balancing normally occurs during a normal charge operation, rather than having to do an additional balancing cycle.
- The Nickel Hydrogen energy storage technology was also found to have a high discharge even during relatively short periods of idle time. This made the technology a poor choice for use cases with long idle periods such as acting as a backup power source during an outage.
- The system was also found to prematurely end P/2 discharge cycles due to two bad energy storage vessels. This resulted in the inability to extract all the energy from the rest of system despite only two of the energy storage vessels being unable to provide any more energy. It should be noted that this greatly impacted this small-scale system because it only consisted of a single string. One or two bad energy storage vessels may not have as much of an impact on a larger system that consisted of multiple strings.

Customer Benefits:

- Once the Nickel Hydrogen energy storage technology is fully commercialized and more widely adopted, it is expected that the technology will be cheaper than Lithium-Ion for long duration use cases.
- Nickel Hydrogen energy storage is also expected to have a higher cycle life than that of its lithium-ion energy storage counterparts, meaning that Nickel Hydrogen energy storage systems are expected to last longer and will not require the same level of augmentation and replacement to continue to provide its specified power and energy over its lifetime. This will translate to long-term cost savings for ratepayers if SCE deploys a Nickel Hydrogen energy storage system to address a grid need.
- The battery systems provided by the vendor will continue to be enhanced and refined from feedback SCE provided to the vendor during the testing.

<u>Anticipated RFPs</u>

- There are no anticipated RFPs.

<u>Industry Advancement</u>

- The testing and results of the testing were published in a paper titled *Beyond Lithium-ion Battery Energy Storage Systems: Technology Testing and Evaluation at SCE"* submitted to the IEEE PESGM conference.
- The results will also be presented at a 2026 DistribuTech panel titled Advancing Long-Duration BESS Testing: Bridging Innovation and Implementation.
- The lessons learned from deploying the test article at an SCE facility have been implemented in the internal processes and procedures that will be used for future test articles and deployments.

4. Control and Protection for Microgrids and Virtual Power Plants

Investment Plan Period	**Assignment to Value Chain**
3rd Triennial Plan (2018 – 2020)	Distribution

<u>Objective & Scope:</u>

Project objectives include:

- Provide a standard method to assess a microgrid controller's performance in maintaining system stability by regulating power flows, managing voltage levels, and reducing frequency deviations within the microgrid. These factors are crucial for preventing disruptions or instabilities.
- Evaluate the controller's ability to isolate the microgrid from the upstream network, maintain critical loads, and facilitate reconnection to the grid. This capability is very important for ensuring the microgrid's operational independence and resilience.
- Analyze the reliability and dependability of the communication protocols and connections as well as ensure data integrity, both of which are vital to the efficient operation of the microgrid and prevention of potential disruptions.

The decision to focus on the University of California, Irvine's (UCI's) highly complex microgrid in this project was made with a goal of tackling real-world power system applications. However, due to the inherent complexities of the model and the need to adapt to the control and protection challenges posed by inverter-based resources (IBRs), the project team needed to make some reductions in the model to accommodate the computational limitations of the Real-Time Digital Simulator (RTDS) software. Despite these changes, the model remained a robust representation of a microgrid power system, and the simulation verified the impacts of load disturbances, operational control strategies, smooth transitions, and auto synchronization on the microgrid's dynamic response. From a control perspective, the project included the design of several layers of control to provide resilient and reliable microgrid operation. The primary layer of control regulated the voltage and frequency within the microgrid. A secondary control layer managed the overall microgrid operation, which included load shedding, islanding detection, fault detection, and isolation. In addition, the project emphasized the strategic integration of Hardware-in-the-Loop (HIL) testing within the controlled confines of the lab environment to examine and assess the real equipment deployed in the field and earmarked for future microgrids. This evaluation encompassed stress testing, performance testing, and resilience testing under a variety of use case scenarios, with a goal of confirming the system's efficiency and dependability, as well as detecting any weak points. SCE completed this project 2024, but SCE was still preparing the final project report at the publication of the 2024 EPIC Annual Report. The Final Report has been posted on the PICG's public EPIC website, and it is included with this annual report.
Schedule: Q3 2019 – Q3 2025
History of the project SCE is continuing on the ambitious journey detailed in "Pathway 2045," a data-based analysis of the steps California must take to clean the electric grid and reach carbon neutrality in just two decades. Pathway 2045 concludes that achieving decarbonization requires powering 100% of retail sales with carbon-free electricity, electrifying transportation, and buildings, and using low-carbon fuels for technologies that are not viable for electrification. Electrification will further increase customers' reliance on the grid, underscoring the need to build in additional resilience to withstand the more frequent and severe weather conditions due to climate change impacts. Microgrids provide a promising solution to mitigate these challenges by offering the potential to alleviate some of the load when the grid is overloaded, or, during an outage, by deploying their Distributed Energy Resources (DER) assets, including clean energy sources such as solar power.

This strategy can enhance system resiliency and stability, enabling SCE to continue providing reliable service while moving toward a more sustainable and carbon-neutral future.

As SCE has not yet integrated utility-operated microgrids into its grid, it is crucial to first thoroughly understand the Microgrid Control System (MCS). This includes comprehending its full capabilities and identifying potential operational challenges. Doing so can ensure a seamless integration process, minimizing disruptions and maximizing the benefits of this technology. It is also vital to establish robust contingency plans and mitigation strategies to promptly and effectively address any unexpected complications.

To address the task of assimilating utility-operated microgrids into its power system, SCE undertook this project, using a dedicated microgrid testbed in a controlled lab environment. This provided the opportunity for testing and evaluation to determine next steps needed to bring a microgrid to field deployment.

2025 Status Update:

Accomplishments & Success Stories

- As noted in the 2024 Annual Report, SCE completed the project's Final Report in 2025. SCE has included the Final Report in this 2025 Annual Report, and it made the Final Report available on the PICG's public EPIC website at https://database.epicpartnership.org/projects.

Challenges or Setbacks

- The team did not identify additional challenges or setbacks.

Key Findings and Lessons Learned

- Knowledge was gained in the network configuration of a microgrid system that can be used for all future microgrid projects (Pomona Microgrid Test Pad).
- Adding complication (additional elements: DER's, tie breakers) to the microgrid model makes it more difficult to perform tests, protection studies, troubleshooting and obtain results.
- During transition modes, the microgrid controller's role in sending and receiving commands to/from the grid forming asset is critical for maintaining the microgrid stability.
- The successful operation of the microgrid depends not only on the implementation of reliable and resilient control schemes but also on the establishment of a fast and reliable communication network.
- Delays in sending/receiving commands needs to be optimized via the microgrid controller code.
- Having two Battery Energy Storage Systems (BESS) in one clustered microgrid would sometimes cause stability issues, which was mitigated via optimizing inverter controller parameters.
- During a black start procedure, it is advisable to avoid connecting the generation units, especially the IBR units, simultaneously. This is because such a connection can cause significant disturbances, which may trigger frequency and voltage protection elements. To mitigate this issue, it is recommended to create time intervals for connecting generation units in the grid restoration scheme.

- Conducting studies before field deployment can preempt potential issues, allowing for the fine-tuning of control schemes, settings, and other parameters.
- In a microgrid islanded scenario, once a ground fault occurred, ground fault availability on the 12 kV system is dependent on the transformers (winding and size) from the BESS breakers. This is an important consideration for system design and operation.
- The SEL-751 relaying connected to the wye-to-ground/wye-to-ground PT can help detect the ground fault on the 12 kV system and act as backup protection for the DER. This finding underscores the need for comprehensive protection schemes.
- The study has shown that fuses added on the 12 kV side of all load transformers cannot be coordinated with corresponding relays due to the use of a generic fuse size 40E. This highlights the need for careful selection and sizing of protective devices.

Customer Benefits

- In terms of strategic alignment with EPIC goals and SCE customer benefits, the project's outcomes contribute to the development of more resilient and reliable microgrids. By conducting studies before field deployment, SCE can preempt potential issues, leading to the fine-tuning of control schemes, settings, and other parameters. This proactive approach aligns with EPIC's goal of advancing innovative clean energy solutions.
- For SCE customers, this translates into more reliable microgrid operations, minimizing disruptions and ensuring a stable power supply. The project's findings will guide future implementations, contributing to the development of robust and efficient microgrids.

Anticipated RFPs

- There are no anticipated RFPs.

Industry Advancement

- This project has made significant steps in microgrid controller system performance evaluation, contributing to the broader goals of enhancing grid resilience and reliability, and delivering tangible benefits to SCE customers.
- As the world of microgrid power systems continues to evolve, this testbed will enable SCE to continually enhance our distribution power system, making it more robust and reliable. It will also allow SCE to stay at the forefront of technological advancements, ensuring that our microgrid solutions are always up-to-date and effective.
- Moreover, by facilitating continuous learning and improvement, the test bed will play a crucial role in driving our organization's growth and success in the microgrid sector. It will not only help SCE deliver superior value to our customers but also contribute to the broader goal of promoting sustainable and resilient energy systems.

5. Distributed Plug-In Electric Vehicle Charging Resources

Investment Plan Period	**Assignment to Value Chain**
3rd Triennial Plan (2018 – 2020)	Distribution

<u>Objective & Scope:</u> This project will demonstrate PEV fast charging stations with integrated energy storage that can be used to control the grid system impact of fast charging, allowing more of them to be accommodated for a particular cost, and also to respond to grid needs as distributed energy resources when not in use to charge a vehicle. Fast charging units currently demand 25 to 125 kW or more each, and the load cannot be planned or scheduled. This demand is expected to climb to 350 kW or more as advertised by vehicle and charging system suppliers. This intermittent and unpredictable high demand could affect utility planning and could also challenge high deployment of such systems due to their low load factor and potentially alarming bill impacts to customers under current tariffs. Combining fast charging systems with energy storage can result in a higher load factor, while still providing satisfactory service to customers. The size of such storage systems, along with power components, will determine their effectiveness in a particular duty cycle. This is demonstrated in the demands on the system from customers in the real world, which this project will show; the demands on such energy storage systems may be met by the capabilities of used batteries. These measures increase the likelihood of higher numbers of such stations becoming operational. Integrated energy storage provides reliability in the case of grid events – transient or otherwise – and improves charging service in the evolving modern system of increased renewable and distributed generation. This project will demonstrate the reliability improvement of such systems subject to grid events.
Schedule: Q4 2019 – Q4 2025
History of the project SCE's project addresses the sizing of Energy Storage Systems (ESS) tailored for fast charging and grid asset applications. The plan also outlined the utilization of energy storage to perform peak shaving, which could work in tandem with fast charging to increase customer adoption of EVs and potentially reduce costs. This strategy aimed to minimize the risk of oversizing the distribution system as well as increase the use of clean, renewable energy resources. Additionally, the plan included a responsive approach to grid events to minimize customer impact and provided support for distribution circuit Volt/VAR (volt-ampere reactive) control. Given that the growth in EV adoption ultimately will create a market for used batteries, the project also initially planned to assess the advantages and disadvantages of utilizing second-life batteries for integrated ESS applications. When the project was conceived, SCE had identified a major automotive manufacturer as a partner and source of second-life batteries. However, the manufacturer shifted its focus to battery recycling and could not provide SCE with these batteries. SCE attempted to find another source of second-life batteries, preferably integrated with direct current (DC) fast charging but was unsuccessful. Thus, this work was removed from the project. Specific project objectives included: • Establish specifications for the integrated fast charger and energy storage systems.

- Obtain test data measuring performance of close-coupled fast charging/energy storage systems for functions including, but not limited to:
  - Peak shaving,
  - Demand Response (DR) program participation, and
  - Volt/VAR support.
- Create internal knowledge transfer deliverables, including reports, presentations, and workshops.
- Create external knowledge transfer deliverables, including at least one conference presentation and workshops.

2025 Status Update:

Accomplishment & Success Stories

- The Project completed the closeout of the project.
- The team has also met with internal Partners to discuss how the findings from this project can be used for internal fleet electrification efforts and for vehicle resiliency.

Challenges or Setbacks

- The project encountered significant challenges due to delays in procuring power systems. SCE faced difficulties in acquiring necessary equipment promptly.
- The Team mitigated the impacts of the worldwide manufacturing and logistical shortage by amending test procedures and was able to complete testing on schedule.

Key Findings and Lessons Learned

- Through internal and external discussions with stakeholders, the Team developed test procedures that can be adapted to future microgrid / EV charge management testing.
- The Team demonstrated that the IEEE 2030.5 commands can be used with an integrated EVSE and ESS to manage loads and perform grid support.
- Second-life batteries remain scarce, constraining the expansion of energy storage systems. Integrating rapid charging technology with these systems can boost load factors, ensuring reliable customer service. The size of these storage units and their power components will dictate their efficiency within a specific duty cycle.

Customer Benefits

- The Team demonstrated that the incorporation of energy storage could enable DC fast charging to be implemented in areas with limited electrical infrastructure capability, as in disadvantaged communities, or could defer upgrades typically needed for fast charging projects.
- The Team demonstrated that the ESS could improve grid reliability and power quality without impacting vehicle charging. This could improve service in impacted areas and provide another revenue stream to offset the costs of the ESS and charging system.

Anticipated RFPs

- There are no anticipated RFPs.

Industry Advancement

- The Team presented at the CIGRE Grid of the Future Conference.
- The Team was able to implement load leveling, demand response, and setting various voltage support functions using the current implementation of IEEE 2030.5.
- The Team's experience is currently being used to provide SCE's Transportations Services as it continues with its efforts to electrify the Edison fleet.

6. Next Generation Distribution Automation III

Investment Plan Period	**Assignment to Value Chain**
3rd Triennial Plan (2018 – 2020)	Distribution

Objective & Scope

The Next Generation Distribution Automation III project (NGDA III) will integrate new Field Area Network (FAN) wireless radio to automation devices and continue to improve control functionality. It will provide greater situational awareness to allow system operators to manage the grid with higher Distribution Energy Resource (DER) penetration and be ready to support Distribution System Operators (DSOs). It will integrate 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. This project will demonstrate technologies that are applicable for both overhead and underground distribution circuits.

The NGDA III project establishes a foundational capability for secure, scalable, and cost-effective integration of grid-connected devices and applications. As the electric grid becomes more digitally enabled and reliant on distributed assets, the ability to securely onboard, authenticate, and manage devices is no longer optional: it is foundational to deliver reliable service without escalating operational risk or cost.

Together, these efforts shift security and device enablement from project-by-project implementations to a reusable, standardized enterprise capability. Device management ensures endpoints are inventoried, governed, and lifecycle-controlled; secure protocol ensures that only trusted users, devices, and services can access systems; and the substation security enables cryptographically secure communications through controlled key distribution and lifecycle management. This integrated approach reduces duplication, simplifies future deployments, and strengthens cybersecurity across the NGDA III ecosystem.

From a ratepayer perspective, these capabilities support lower costs and improved service quality. By enabling remote configuration, adaptive control, and enhanced situational awareness, NGDA III reduces truck rolls, minimizes outages, and maximizes the use of existing infrastructure, all of which reduce costs to ratepayers. NGDA III allows grid modernization to proceed efficiently, improving reliability for ratepayers and delivering operational savings without requiring disproportionate increases in capital or operating expenditures.

Key features and objectives of each use case of this project include:

• Demonstrating the capability to use an accurate duct bank temperature modeling tool and/or scalable real-time monitoring system. This system would allow for the avoidance of excessive duct bank temperature due to circuit overloading which could lead to premature, catastrophic cable failure. Monitoring the system could provide better situational awareness to proactively manage circuit loading.
• Exploring improvements upon legacy Distribution Network Protocol (DNP) communications for distribution automation by testing and assessing a standardized communication protocol using IEC 61850 to manage field devices for passive activities including commissioning, updates, retirement, and cybersecurity patches. The intent is for the results of the testing to enable uniform, accelerated configuration, and enhanced cybersecurity, extending the protocol used by Substation Automation (SA) to the distribution grid.
• Providing a lab-only demonstration of next generation distribution automation controller devices, capable of using the DNP v3 Secure Authentication version 5 protocol, to communicate with a lab sandbox Field Device Management Platform (FDMP). The intent of the lab test system is to validate the ability of the next generation controller devices to send/receive messages required for SCE device management.
• A major part of this project will be to test the feasibility of enhancing encryption to communication between protection devices at substations. The key aspects of effective cybersecurity communication are the distribution of the encryption keys through a key distribution center that would act as a centralized authority. This improved cybersecurity level is a critical need as utilities move towards an increasingly connected network. This will include:
  o A demonstration that grid communication can be made more secure by implementing a routable second edition of protocols, as defined by the latest IEC 61850 standard.
  o Using a key distribution center to manage key and policy distribution, ensuring secure communication across multiple locations in the grid.
 	
This substation security will provide management of system enrollment, key distribution, and access control, which is essential for securing multicast communication and encryption of protocol messages.

Schedule Q3 2019 – Q3 2026
Project History This project will leverage lessons learned from the EPIC 2, Next Generation Distribution Automation II project aimed at improving distribution automation operations and enabling more flexible, centrally managed field devices. Earlier work demonstrated the need for improved methods to configure distribution automation controllers remotely but was constrained by legacy wireless communication and operational approaches that required manual, on site updates. The current project evaluates the use of device management (DvM) within SCE's Grid Management System (GMS), assuming integration with modern field communications. Device management serves as a platform to assess the feasibility of remotely managing and updating protection and configuration settings on distribution automation device controllers, supporting more adaptive and responsive grid operations. The effort also helps define functional

requirements needed for future device compatibility and vendor alignment. By demonstrating the ability to manage and update settings remotely, the project advances previous efforts by reducing reliance on time intensive field visits for routine configuration changes. This approach streamlines operations, improves response time to changing grid conditions, and supports a more efficient use of field resources. It is designed to inform future planning decisions related to device modernization, communications integration, and operational practices.

Application testing for the device management lab kit drops was initially witnessed off-premises. However, vendor-related delays prevented completion of the on-premises testing. As it became clear that these delays would persist, the leadership decided to conclude that phase of the project.

Additionally, improved cybersecurity is a critical need as utilities move towards an increasingly connected network.

Building on earlier work, NGDA III leveraged the lessons learned from the successful protection of DvM to explore the viability of deploying support across SCE's distribution protection assets. A key distribution center (KDC) is a critical component of DvM that will provide cybersecurity and allow it to scale securely by enabling onsite encryption of the protection assets.

The last phase of NDGA III will test the feasibility of utilizing a KDC to add encryption to communication between protection devices at substations. The key aspects of effective cybersecurity communication are the distribution of encryption keys that would act as a centralized authority. Adding encryption keys is necessary to secure substation assets for many multicast groups under the IEC-61850 protocol. This collective alignment positions NGDA III to meet evolving cybersecurity, interoperability, and reliability requirements.

2025 Status Update

<u>Accomplishments & Success Stories</u>

- The project team identified and acquired all major components necessary to perform lab testing of the key distribution center, allowing for testing to begin in Q2 of 2026.
- A test plan and test cases were created to test functionality of desired encryption protocol (in 2026), with the aid of a design vendor.

<u>Challenges or Setbacks</u>

- After the team determined the desired encryption protocol to be used, identifying common devices and vendors where were compatible for the end-state system configuration proved challenging, requiring extensive vendor outreach and market assessment. The team eventually found a set of vendors through extensive outreach for equipment that supported encrypted communication.

<u>Key Findings and Lessons Learned</u>

- The team gained an understanding of how equipment would be installed in the lab to test functionality of the encryption equipment. This will be applied during lab phase setup in 2026. These findings can be scaled for future deployments on SCE's grid.

Customer Benefits

- Validation of device compatibility in 2025 will ultimately increase distribution system resiliency against cybersecurity attacks.
- Our learnings from this project will further influence broader substation initiatives. These improvements to substation design will help improve utilization without requiring costly investment to increase capacity.

Anticipated RFPs

- No RFPs are anticipated to be necessary to achieve the scope of this project.

Industry Advancement

- SCE shared findings on the limitations and deficiencies of the DNP3-SAv5 protocol with the DNP Users Group. The DNP Users Group is a California nonprofit public mutual benefit nonprofit Corporation, whose primary purpose is to maintain and promote the Distributed Network Protocol (DNP3), a non-proprietary, standards-based communication protocol widely used in the utility industry.[106]
- The project team has been in direct communication with a key contributor to R-GOOSE, the IEC-61850 communication protocol, the industry standard for digitized protection. The team will continue to share lessons learned with the author and intends to share lessons learned at industry conferences such as the 2026 IEC 61850 Interoperability Testing event and DISTRIBUTECH.

7. SA-3 Phase III Field Demonstrations

Investment Plan Period	**Assignment to Value Chain**
3rd Triennial Plan (2018 – 2020)	Transmission
Objective & Scope The overall goal of SA-3 Phase III Field Demonstrations is to demonstrate a modern substation automation system for use in transmission substations by adopting scalable technology that enables advanced functionality to meet NERC CIP compliance and IT cybersecurity requirements. SA-3 Phase III includes the evaluation of virtual protection relays as a next generation substation protection system to improve SCE's ability to adapt to protection challenges related to increasing presence of inverter-based resources. Furthermore, the virtualization of protection relays is expected to reduce the footprint of the substation control room. This may result in faster, more cost-effective construction for new substations. These benefits will result in cost savings, ability to support increasing load growth, and improved reliability from a customer perspective. In addition, SA-3 Phase III will demonstrate IEC61850 capable	

[106] www.dnp.org/About/DNP-Users-Group

automation and control systems, ensuring interoperability and mitigating risks of technology obsolescence. SA3 Phase III will demonstrate new technologies for substation apparatus, including the implementation of Arc Suppression Coils for resonant grounded substations.

The findings from SA-3 Phase III will inform SCE's protection strategy and roadmap, leading to targeted deployments of the demonstrated technologies. This will result in improved grid reliability and cost savings for SCE ratepayers. The substation protection, automation, and control systems demonstrated will provide efficiency in deployment and maintenance that will reduce construction costs, commissioning time, and maintenance outage times. These systems will also provide improved adaptability for protection systems, which will result in improved safety and reliability.

Schedule

Q3 2019 – Q3 2026

Project History

SCE's previous EPIC 1 SA3 Field Demonstration (SCE-IIM-13-0150) and EPIC 2 Systems Intelligence & Situational Awareness (SCE-IIM-015-0015) have allowed SCE to evaluate technologies for substation digitalization and adoption of the industry standard, IEC61850.

The efforts around digitizing data for substation protection has enabled the ability to virtualize substation devices responsible for protection, automation, and control.
Substation protection relays have typically been single-vendor solution to guarantee hardware and software compatibility and performance requirements. Virtual Protection Relays integrate hardware and software from different vendors and require collaboration to ensure that protection applications operate reliably.

2025 Status Update

Accomplishments & Success Stories

- The project team completed lab testing and evaluation of the virtual protection relay proof of concept demonstration. At the conclusion of the lab demonstration, the project team delivered knowledge transfer sessions to key internal stakeholders along with recommendations to incorporate this technology in a field demonstration.
- The project team met with internal stakeholders to identify potential field demonstration locations and have worked with stakeholders to identify scope of a field demonstration following the close out of the EPIC project.

Challenges or Setbacks

- The project team identified certain substation protection functions that were not technically feasible to include in the scope of lab testing at the time of the lab demonstration. Line differential protection for virtual protection systems could be further explored in future projects.

Key Findings and Lessons Learned

- Through the SA-3 Phase III field demonstrations project, the project team identified several key system requirements and specifications that must be considered for future field demonstration projects. These included approaches to virtual protection hardware sizing, redundancy architectures, and communication network architecture designs. The project team has also shared these key findings and lessons learned through conference presentations and papers.

Customer Benefits

- This project demonstrated new technologies for Substation Automation Phase 3 as feasible options for future substation designs. This technology can support efforts related to compact substation designs and substation digitalization.
- Customers will benefit from improved grid reliability resulting from substation protection applications and increasing redundancy in substation protection and control architectures that can be achieved in virtual protection, IEC61850 capable automation, and resonant grounded substation transformers.
- In addition, the reduction in substation control room footprint, construction costs, and construction time is expected to result in customer cost savings.

Anticipated RFPs

- There are no anticipated RFPs.

Industry Advancement

- The team delivered presentations at the Western Protective Relay Conference and Protection Automation & Control World Conference in 2025. These presentations facilitated sharing findings and lessons learned.

8. Service and Distribution Centers of the Future

Investment Plan Period 3rd Triennial Plan (2018 – 2020)	**Assignment to Value Chain** Distribution

Objective & Scope

The Service and Distribution Center of the Future (SCoF) project aims to demonstrate how an integrated microgrid architecture can modernize SCE service centers by enabling reliable Electric Vehicle (EV) fleet charging and low-impact grid interaction through the coordinated use of a Microgrid Control System (MCS), Charge Management System (CMS) and Grid Management System (GMS).

This project delivers direct ratepayer value by improving reliability on the circuit serving the Service Center; during a circuit outage, the microgrid can provide grid support to help maintain uninterrupted electric service for nearby customers and businesses.

SCoF provides a scalable, resilient model for SCE facilities—supporting large-scale fleet electrification, improving reliability, and demonstrating how service centers can operate effectively even under grid stress or disruptions. When scaled across SCE service centers, this

capability will improve fleet readiness and enable faster, more effective field response—supporting optimal repair and restoration services for the communities SCE serves. The project develops and validates this technology across simulation, hardware-in-the-loop, and field environments to prove it can autonomously manage EV charging, curtail building loads, operate a Mobile Battery Energy Storage System (MBESS), island during outages, and resynchronize safely under Rule 21 criteria. This work addresses key operational challenges such as high-demand EV charging, uncoordinated behind-the-meter assets, and vulnerability to grid disturbances by creating a unified control framework that optimizes power flow, reduces peak loading, and ensures fleet readiness even during unplanned outages.
Schedule Q4 2019 – Q2 2026
Project History SCoF originated under the EPIC III investment plan as GT-18-0017, where early efforts focused on defining the microgrid architecture, procuring the Microgrid Control System (MCS), and preparing the systems required to support EV fleet charging, building load management, and grid-support functions. The project advanced significantly through a multi-stage validation process that began with vendor-based Factory Acceptance Testing (FAT), followed by Controller-Hardware-in-the-Loop (CHIL) testing using a Real-Time Digital Simulator (RTDS) at the Fenwick lab, and culminating in full Power-Hardware-in-the-Loop (PHIL) testing at the Pomona Microgrid Test Lab. These PHIL demonstrations successfully integrated and validated real hardware, including the Battery Energy Storage System (BESS**)**, Electric Vehicle Supply Equipment (EVSE), charging unit, relays, metering, and the MCS, across key operating modes such as grid-connected operation, islanding, live reconnection, and black start. The Control-Hardware-in-the-Loop (CHIL) testing using a Real-Time Digital Simulator (RTDS) at the Fenwick lab utilized the MCS test bed and learnings from the EPIC III GT-18-0018_Control and Protection project. The MCS test bed was first installed and configured for the GT-18-0018_Control and Protection project and is now going to be used in testing all future MG projects. Lessons learned from tests in GT-18-0018 (the EPIC 3 project Control and Protection for Microgrids and Virtual Power Plants) established the initial MCS performance baseline. Control scheme and parameter refinements improved microgrid performance, and the resulting elements were carried forward as a baseline to the Service Center project, reducing commissioning and tuning time. The protection testing during Control and Protection allowed SCE to develop a protection philosophy for Microgrids. This philosophy was leveraged for the Service Center project and helped in identifying the needed protection relay elements that are critical in protecting the MG.

SCE started a new effort with the capital-funded field deployment project GT-24-0107, which continues the progression toward operational implementation at the San Joaquin Valley Service Center. The remaining work focuses on maturing the QA environment, refining network design, preparing field-ready configurations, and addressing scaling considerations identified during testing.

2025 Status Update

Accomplishments & Success Stories

- The SCoF project achieved several major technical milestones this year, including completion of Controller-Hardware-in-the-Loop (CHIL) testing using RTDS at the Fenwick lab and full Power-Hardware-in-the-Loop (PHIL) validation at the Pomona Microgrid Test Lab.
- During PHIL testing, the team successfully integrated and validated the MCS, BESS, EV charging power unit, EVSE, relays, and revenue-grade metering, demonstrating all required microgrid operating modes: grid-connected operation, islanding, live reconnection, automatic reconnection, black start, and automatic black start.
- These accomplishments confirm that the technical architecture can support real-world service-center operations and EV fleet charging with validated interoperability across key hardware components.
- The team also coordinated closely with IT, Cybersecurity, vendor engineers, and internal engineering partners to plan the transition from EPIC lab validation to the capital-funded field deployment phase, including QA environment planning, network-design updates, and build sequencing for the first Service Center installation.

Challenges or Setbacks

- Throughout the SCoF testing phases, the project encountered several integration-related complexities that required additional coordination and refinement.
  - Integration of the IT network and firewall with the Microgrid Control System (MCS) involved aligning cybersecurity requirements, firewall rules, and network access to enable reliable communication between control, protection, and monitoring devices.
  - While these elements were ultimately resolved, the level of coordination required was greater than initially anticipated and highlighted the importance of establishing network readiness early in the testing lifecycle to support efficient testing and future deployment activities.
- System-level testing also surfaced dependencies related to hardware configuration and protection implementation.
  - Complete and approved switchgear documentation, including detailed breaker control schematics, proved critical for efficient validation and troubleshooting during testing. In addition, verification of controllable breaker wiring—particularly at the Point of Interconnection (POI)—was essential to ensuring proper system behavior during transition scenarios.
  - Addressing these items during testing reinforced the need for thorough pre-test verification and close coordination between engineering, construction, and testing personnel.

- Integration of the battery energy storage system (BESS) introduced further technical considerations.
    - The BESS capabilities required careful alignment with the ratings of site equipment and associated protection settings to ensure compatibility within the test environment.
    - Additionally, the absence of fully standardized control interfaces across vendors necessitated focused configuration and validation to integrate all required BESS operating modes through the MCS.
    - Coordinating BESS controls with protection logic and POI breaker sequencing added complexity but provided valuable insights into system behavior under realistic operating conditions.
- Finally, supporting infrastructure considerations emerged as an important aspect of system readiness.
    - Accurate time synchronization across devices depended on proper configuration of IRIG-B and NTP connections to support event analysis and data integrity.
    - Integration of the GMS simulator (ASE2000) was useful in validating key operational signals; however, it also emphasized the importance of clearly defined I/O interfaces prior to testing.
    - Collectively, these experiences demonstrated the value of a structured, phased testing approach and reinforced best practices that will help streamline future Service Center microgrid deployments.

Key Findings and Lessons Learned

- Through PHIL testing and coordination with internal and external stakeholders, the team gained critical insights that directly advanced the SCoF microgrid design and deployment process.
- Testing showed that the temporary NOMAD Traveler BESS introduced complex startup sequences, black-start inconsistencies, and auto-reconnect failures, highlighting the need for simplified backup-power architecture, corrected interlock logic, and improved firmware to support autonomous field operation.
- The campaign also revealed grid-simulator power limitations that constrained full validation of advanced BESS grid-support functions, emphasizing the need for higher-capacity simulation for future projects.
- These lessons informed refinements to MCS sequencing, BESS interface requirements, and testbed preparation practices, and they created opportunities for internal tech transfer—particularly around earlier definition of I/O mappings, alignment of hardware expectations between lab and field, and more rigorous evaluation of representative versus final hardware prior to deployment.

Customer Benefits

- The validated microgrid architecture can support reliable EV fleet charging without requiring upstream distribution upgrades, reducing operational strain, and enabling fleet mobilization even during outages. PHIL results confirmed that the system can island and operate from

BESS during grid loss, improving service-center resilience and reducing risks of operational delays.
- When deployed across more than 100 planned service-center sites, the architecture could reduce peak demand impacts, enhance service-center reliability, and support electrification of SCE's operational fleet—all of which translate to improved outage response capabilities, more efficient utility operations, and long-term cost avoidance for ratepayers. This project directly supports SCE's operational resilience and transportation electrification goals within its own facilities.
- Other customers could replicate this design which could further reduce their implementation costs. SCE plans to scale this standardized solution which can significantly reduce cost over custom solutions at every Service Center this ultimately results in lower costs to our ratepayers.
- By enabling reliable, scalable charging for electrified service-center fleets, the project supports the transition away from combustion vehicles, reducing tailpipe emissions, improving local air quality, and lowering greenhouse-gas emissions over time.

Anticipated RFPs
- There are no anticipated RFPs.

9. Smart City Demonstration

Investment Plan Period	Assignment to Value Chain
3rd Triennial Plan (2018 – 2020)	Grid Operation/Market Design

Objective & Scope

The efforts being put forth for this project are producing significant benefits for SCE, providing a transferable microgrid blueprint, reducing deployment risk, improving DER orchestration practices, strengthening outage-management capabilities, and enabling more resilient, flexible operations for future SCE microgrid initiatives.

Without the learnings from this project, critical community facilities may remain vulnerable during outages and large-scale microgrid deployment may be delayed, limiting grid-support capability and increasing the risk of prolonged service interruptions during grid connected mode for nearby customers and businesses.

Successful completion of this project demonstration will de-risk field deployment and improve the reliability of the Porterville Wastewater Treatment Facility, helping maintain safe, continuous water service for the community during power outages.

The Smart City Demonstration project aims to validate a front-of-the-meter microgrid architecture that enhances SCE's distribution-level resiliency, reliability, and operational flexibility. By leveraging a Microgrid Control System (MCS) capable of orchestrating utility-owned and third-party resources - including a Battery Energy Storage System (BESS), Photovoltaic (PV) systems, protection relays, load assets, and integration with SCE's Grid Management System

(GMS) - the project demonstrates how advanced automation can maintain stable, safe operation across both normal and contingency scenarios. Smart City evaluates this full architecture through a structured test sequence: Factory Acceptance Testing (FAT), real-time Control Hardware in the Loop (CHIL) testing utilizing a Real-Time Digital Simulator (RTDS), Power Hardware in the Loop (PHIL) hardware testing and eventual Quality Assurance (QAS) verification prior to field deployment. These controlled environments enable validation of core operational capabilities such as planned and unplanned islanding, Point of Interconnection (POI) import/export control, black start, reconnection (live and dead), and grid-support services including voltage/frequency regulation, reliability modes, peak shaving, and economic dispatch. The project addresses major operational challenges facing modern distribution systems, including how to maintain power to critical loads during outages, how to safely transition between grid-connected and islanded states, how to coordinate Distribution Energy Resources (DER's) for grid-support functions, and how to identify integration, protection, or communications issues prior to deployment. Through extensive testing and cross-stakeholder collaboration, the project validates a Microgrid Control System (MCS) platform—consisting of Automation Servers, Automation Controllers, Human Machine Interface (HMI), Data Monitoring, and integrated DER interfaces—as a scalable and repeatable microgrid-control solution.
Schedule Q4 2019 – Q1 2027
Project History The Smart City Demonstration project builds on several years of SCE's microgrid development, lab testing, and DER-integration work, beginning with the GT-18-0018 Control and Protection EPIC project. Early design efforts and technical specifications for the Microgrid Control System (MCS), followed by Factory Acceptance Testing (FAT) began in 2022. The FAT phase established the baseline architecture, validated communications interfaces, tested control logic using RTDS-based Hardware in the Loop (HIL) simulation, and revealed foundational requirements around decoupling behavior, POI control, black start sequencing, and DER dispatch. These early tests informed the next stage: CHIL testing at SCE's Fenwick Lab, where the RTDS model and HIL interfaces—jointly developed with Quanta Technology—were refined to more accurately represent inverter-based resource behavior and field conditions. The Fenwick work advanced SCE's modeling fidelity and uncovered integration challenges such as time synchronization gaps, protection-logic interactions, and the importance of aligning MCS logic with DER operating modes. Building on this foundation, SCE progressed to PHIL testing at Pomona, where actual hardware—including a BESS, PV inverter, load bank, protection relays, and GMS simulator—was integrated to validate the full Smart City microgrid stack. This stage demonstrated end-to-end functionality for planned/unplanned islanding, POI transitions, grid-support services, black start, and outage-scheduling sequences, while surfacing hardware-specific insights such as BESS transient behavior, POI wiring dependencies, and DER control nuances.

Collectively, these efforts represent SCE's most complete microgrid validation pathway to date, advancing prior EPIC work by uniting simulation, HIL, PHIL, and near-field operational readiness into a single, repeatable process for future microgrid deployments. This is getting SCE closer to deploying the first Front of the Meter (FTM) Microgrid System. The lessons learned from this first FTM deployment will pave the way for many more Microgrid System deployments which will provide resiliency to critical loads across disadvantage communities.

The project also clarifies several limits that future work can address, such as the inverter-model fidelity gap between RTDS and field hardware, BESS Power Converter System seamless-transition constraints, voltage and frequency protection considerations especially in islanded mode, and grid-simulator capacity limits that restrict high-power transient testing. These findings raise forward-looking questions around how future microgrid platforms should integrate newer grid-forming inverter technologies, how to improve DER ride-through consistency, how to automate sequencing with higher reliability, and how to scale microgrid control across multiple distribution nodes. These questions and gaps will be addressed during the first FTM deployment at the MG design stage and validated during the field commissioning and Site Acceptance Testing (SAT).

Advancing these areas could produce significant ratepayer benefits—stronger outage resilience through reliable islanding, improved safety through better-coordinated protection, reduced emissions via optimized DER dispatch, and support for electrification through flexible, grid-supportive DER control. Smart City therefore serves as both a validation of current capabilities and a strategic foundation for the next generation of SCE microgrid, resiliency, and DER-orchestration programs.

2025 Status Update:

Accomplishments & Success Stories

- The Smart City project advanced SCE's microgrid capabilities by validating the full Microgrid Control System (MCS) across staged FAT, CHIL, and PHIL test environments, demonstrating reliable execution of POI import/export control, planned and unplanned islanding, black-start operation, outage-scheduling transitions, and grid-support functions across both simulated and real-hardware conditions. Successful validation will result in minimizing field deployment risks and improving the reliability of the Porterville Wastewater Treatment Facility, helping maintain safe, continuous water service for the community during power outages.
- Through this work, the team successfully integrated a BESS, PV inverter, load bank, protection relays, and GMS simulator into a functioning microgrid and evaluated real-world DER behaviors such as active/reactive power sharing, State Of Charge (SOC)-based shutdown, and inverter transient response, while identifying key technology insights including time-synchronization needs, network-configuration requirements, model fidelity gaps, and Powerpack limitations in seamless transitions and high islanded loading.
- The team also collaborated closely with IT/Network Engineering to ensure proper firewall rules, device routing, time-sync infrastructure, and communication pathways were aligned with the needs of DER interoperability and MCS-to-GMS signaling, reinforcing the technical readiness of the Smart City system for field demonstration.

- The testing and results thus far have demonstrated end-to-end MCS functionality for planned/unplanned islanding, POI transitions, grid-support services, black start, and outage-scheduling sequences. Collectively, these efforts represent SCE's most complete microgrid validation pathway to date, advancing prior EPIC work by uniting simulation, HIL, PHIL, and near-field operational readiness into a single, repeatable process for future microgrid deployments. This is getting SCE closer to deploying the first Front of the Meter (FTM) Microgrid System. The lessons learned from this first FTM deployment will pave the way for many more Microgrid System deployments which will provide resiliency to critical loads across disadvantage communities.

Challenges or Setbacks

- Across FAT, CHIL, and PHIL testing, the project faced several substantial challenges, most critically the BESS's inability to reliably support seamless transitions—exhibiting voltage collapse, 0 Volt output drops, truncated frequency reporting, and instability above ~60 kW in islanded mode during PHIL testing. Earlier stages revealed additional setbacks: RTDS model and inverter-control limitations during FAT and time-synchronization and communication failures during CHIL that affected the Microgrid Controller (MGC), Front End Processor (FEP), and Data Monitoring system. The team mitigated these issues by refining MCS sequencing, tuning DER dispatch logic, correcting POI wiring, and working with IT/Network Engineering to resolve firewall, routing, and Network Time Protocol (NTP) / Inter Range Instrumentation Group (IRIG) timing problems. This was a critical failure in regard to supporting seamless transition because it results in the end user experiencing a black out rather than an unnoticeable transition from grid connected to islanded mode. This critical inability is going to be resolved in the next phase of testing via a software / hardware upgrade from the BESS vendor.
- Moving forward, the team plans to improve inverter modeling, engage vendors on hardware limitations, and utilize higher-capacity grid simulators to better evaluate transient behavior.
- These setbacks highlight broader impediments—such as vendor data restrictions, hardware constraints, and limited insight into proprietary inverter controls—that could affect future microgrid project portfolios and underscore the need for continued cross-team coordination and technology advancement.

Key Findings and Lessons Learned

Key Findings

- **MCS and Seamless Transition Performance:** The Microgrid Control System (MCS) demonstrated effective coordination of distributed energy resources across grid-connected and islanded operating modes. Black start, planned islanding, and unplanned islanding were successfully supported under no-load conditions; however, seamless transitions under loaded conditions above approximately 40 kW were not consistently achieved. In these scenarios, the BESS voltage dropped to zero and required a black-start sequence, indicating limitations in inverter control maturity for higher-load seamless transitions.
- **Protection Coordination Gaps:** Observations showed that the BESS inverter did not issue a trip command under unstable islanded conditions, indicating that inverter-based voltage and

frequency protections were insufficient. This exposed a protection coordination gap that could lead to equipment damage if not addressed through independent protective functions.
- **Grid Simulator and Testing Constraints:** Grid simulator power flow limitations required careful management of load and PV generation to maintain load mismatch below approximately 40 kW. Within these constraints, unplanned seamless transitions were successfully demonstrated by intentionally driving abnormal voltage and frequency conditions that correctly triggered decoupling via the SEL-651R(A) relay, confirming appropriate relay functionality under abnormal grid conditions.

Lessons Learned
- **Protection System Design:** Generator breaker protective relays must include properly coordinated voltage and frequency protection to supplement inverter protections. Future protection system designs should explicitly incorporate time coordination between inverter ride-through settings and BESS breaker relay trip logic as part of the overall protection philosophy.
- **Inverter Control Maturity:** Seamless transition capability must be validated under realistic loading conditions, as no-load testing alone does not fully capture inverter behavior during dynamic events. Inverter hardware and control maturity directly impact voltage stability and transition performance at higher load levels.
- **Test Planning and Vendor Responsibilities:** Controller vendors should develop detailed, lab-specific test plans aligned with system integration objectives and available laboratory capabilities, with clear traceability between test cases, equipment, and lab features.
- **Integration and Test Execution Practices:** Post-integration testing requires continued engagement from IT and firewall teams for at least two weeks to support connectivity, security, and network validation. In addition, complete as-built three-phase control wiring diagrams should be issued at least two weeks prior to testing to support efficient verification and troubleshooting, and data logging systems should be activated prior to test execution to ensure full traceability.

Customer Benefits
- Through FAT, CHIL, and PHIL testing, the Smart City project identified new sources of customer value by demonstrating that an MCS-coordinated microgrid can reliably execute planned and unplanned islanding, black start, reconnection, and grid-support services, thereby improving outage resilience and reducing dependency on traditional infrastructure investments.
- The project validated that inverter-based DERs—when properly managed through the MCS—can maintain critical load support, regulate voltage and frequency, and reduce stress on the grid during abnormal conditions, directly contributing to reliability and safety benefits for customers.
- Proper management of the DERs through the MCS consists of inverter-based DERs operating under centralized control can coordinate dispatch, enforces limits, regulates voltage and frequency, and manages grid-connected and islanded transitions. Abnormal conditions include loss of the utility source, voltage or frequency excursions, unplanned islanding, and

constrained or islanded operation. This project showed that, under these conditions, MCS-coordinated DERs can maintain critical loads, regulate system performance, and reduce system stress, supporting improved reliability and safety during grid disturbances.
- The team quantified performance characteristics such as stable active/reactive power sharing, SOC-driven load preservation, and successful load restoration during black start.
- If deployed system-wide across SCE's service territory, these capabilities could materially improve service continuity in high-risk or climate-vulnerable regions, reduce outage durations, and support cleaner energy delivery by maximizing the use of PV and BESS during islanded or constrained grid conditions.
- Smart City outcomes are directly scalable into future microgrid and resiliency portfolios, supporting Distribution Volt-VAR Control (DVC) and other grid-modernization initiatives by enabling DERs to provide localized grid support.
- The project's validation of inverter-based microgrids also supports disadvantaged and low-income communities by paving the way for resiliency hubs and load-support zones that maintain power during grid interruptions.
- Finally, by demonstrating how microgrids can integrate renewable resources, the project showed how centralized control through the MCS coordinates DER dispatch, enforces operating limits, and regulates voltage and frequency to maintain reliable operation during abnormal conditions. Through coordinated management of DER assets, the microgrid reduces reliance on backup fossil generation, improves operational flexibility, and maintains critical load support during grid disturbances, advancing ratepayer benefits aligned with California's clean-energy and climate goals.

<u>Anticipated RFPs</u>
- There are no anticipated RFPs.

<u>Industry Advancement</u>
- The Smart City project advanced industry knowledge by generating validated insights on microgrid controls, inverter behavior, and DER interoperability, which SCE has shared across internal engineering and IT/Network forums, so the findings actively inform ongoing grid-modernization efforts.
- The project's testing results highlighted gaps in inverter model fidelity, seamless-transition performance, and time-synchronization precision—findings that align with broader industry and standards discussions and were communicated to vendors, particularly regarding BESS limitations observed during PHIL testing.
- Smart City also strengthened internal SCE processes by improving requirements for firewall configuration, routing, IRIG/NTP timing, and validation of DER models, ensuring future microgrid deployments benefit directly from these learnings.

10. Storage-Based Distribution DC Link

Investment Plan Period	**Assignment to Value Chain**
3rd Triennial Plan (2018 – 2020)	Distribution

Objective & Scope The Storage-Based Distribution DC Link will evaluate a battery energy storage system (BESS) that utilizes a novel inverter architecture capable of connecting the BESS to two adjacent circuits through the usage of a DC bus. This type of technology will enable a single battery energy storage system to be able to directly support multiple circuits, thereby increasing the value proposition of individual deployments. This technology can provide a more flexible option to tie switches used for load rolling. While tie switches already exist to help transfer load from one circuit to another, they can only transfer “fixed” amounts of load and sometimes require a crew to perform the switch. A DC link system would be able to transfer dynamic amounts of power between circuits. Such a system would also be able to quickly respond to overload conditions compared to conventional methods. The inclusion of an energy storage system with this technology builds upon this capability; traditional battery energy storage systems are connected to a single circuit, while energy storage combined with a DC link would be able to provide energy to both circuits at the same time. The DC Link would allow for better utilization of existing distribution assets, deferring to expensive capital circuit upgrades. Enabling fewer/smaller energy storage deployments to provide benefits to a wider area will reduce the costs of providing grid reliability to ratepayers and improve the viability of energy storage as a solution in areas where land availability is a concern. In addition, grid operators would benefit from needing to manage a smaller quantity of energy storage systems.
Schedule Q3 2019 – Q2 2026
Project History The team built on its substantial progress from 2023 into early 2024, but the situation changed in March 2024, when the Supplier was unable to solve technical issues with Tie Controller product and decided to discontinue it. “Tie Controller” is the technical term used to refer to the power flow control system needed to manage power between two circuits. As a result of the product being discontinued, the project team closed the original purchase order and pursued other possible DC Link products through an RFI and RFP process in 2024. This second RFP was released in November 2024, where only two vendors responded. After technical evaluations, it was determined that neither proposal sufficiently met the requirements of the project. As a result, the decision was made to close the project without any demonstration. As the project never advanced past the procurement phase, the question of the technology’s feasibility in the actual distribution network remains unanswered. Because the technology requires the co-location of at least two circuits at a location that is not the substation, SCE must analyze how many circuits would (a) benefit from sharing via DC Link and (b) are close enough together at a location where placement of a grid tie and energy storage would be beneficial.

DC Link technology would provide ratepayer benefits and support EPIC's primary principles of promoting greater reliability, improving affordability, and improving environmental sustainability through the integration of renewables and DERs by extending the traditional benefits provided by a single energy storage system to multiple circuits. This will effectively improve the utilization and value of the storage asset, while enhancing operational flexibility and reliability.

Development of DC Link systems would also progress toward the goal of clean energy transition in California. For example, a storage-based DC Link can increase the hosting capacity of a circuit, allowing additional DER customers to connect. In addition, the project can improve reliability and resiliency by providing power from an under-utilized circuit to an overloaded circuit. It can also defer conventional grid upgrades such as reconductoring overhead lines or underground cables.

2025 Status Update

Accomplishments & Success Stories

- The team evaluated proposals from the second RFP and determined that none of the proposals had reached sufficient technology readiness for a demonstration. Based on these results, the team decided to close the project.

Challenges or Setbacks

- None of the engaged vendors were able to propose a solution that met the project requirements.
- The originally selected vendor elected to stop development on their proposed product due to issues with phase voltage imbalances, fault condition handling, an underdeveloped control system, and lack of inductance between the circuit and the device.
- In the second RFP, which was intended to replace the original vendor, only two vendors submitted a proposal. Of the two, one did not have a DC Link product in their portfolio and proposed a custom build. The other vendor's proposed system had undergone a factory test of the individual components, but not as an integrated system.
- Technical evaluations of both proposals above resulted in the conclusion that neither product was ready for technical demonstration - no diagrams, one-lines, or test reports were provided in either proposal package. It was determined that significant development work would be required with either vendor, which would likely fall outside the scope of an EPIC Technology Demonstration & Deployment project.

Key Findings and Lessons Learned

- While the individual technologies that make up Storage-based DC Link already exist, a lot of integration work is required from the vendors. Vendors have little to no experience with developing such a system. Based on the information available at the time of the second RFP, a DC Link system as envisioned by this project has never been installed elsewhere.
- Vendors may need additional time to develop their DC Link solution.
- Considering the highly specific use case for Storage-based DC Link, vendors may need external incentives (such as state/federal grants) to develop such a system. One vendor cited concerns with market viability; there did not seem to be enough product demand to continue

production efforts. In other words, vendors may be unlikely to develop this type of product on their own without external funding.

- The robustness of the control system is a key consideration in this technology. The system must be stable and able to precisely control voltage magnitude, phase angle, power flow direction, as well as its own internal multi-level converters.
- The team identified that utilizing a Tie Controller and existing BESS can significantly increase the hosting capacity to connect DER customers. This was verified by performing computer simulations on actual SCE circuits and calculating the power flow results. In addition, the Tie Controller and BESS could respond to real-time changes in DER output by maintaining proper voltage levels. This is especially important with volatile generation sources such as photo-voltaic panels.
- A key finding is that the protection design must be understood prior to installing a Tie Controller on actual circuits. The Tie Controller could have an effect on the main breaker of the substation, which could require an adjustment of the breaker settings. Since the Tie Controller is always connected between the two distribution circuits, it is effectively paralleling the circuits at all times. This fact changes the overall impedance seen by the substation at the feeder head.

Customer Benefits

- Development of DC Link systems would progress toward the goal of clean energy transition in California. DC Link deployments would increase the hosting capacity of the connected circuits, allowing more DER interconnections without upgrading the circuits. Doing so will reduce interconnection times for customers and allow more of them to participate in the energy market with their residential DER systems.
- A DC Link can improve reliability and resiliency by providing power from an under-utilized circuit to an overloaded circuit. It can also defer conventional grid upgrades such as reconductoring overhead lines or underground cables.
- Usage of the DC Link to allow energy storage to support multiple circuits will reduce the total amount of energy storage needed to provide reliability and capital upgrade deferment benefits. Higher utilization efficiency for energy storage will result in a better return of investment.

Anticipated RFPs

- There are no anticipated RFPs.

Industry Advancement

- A conference paper detailing how a DC Link system can increase the DER hosting capacity of a circuit was presented at CIGRE 2023. This paper used simulation studies from actual circuits as the basis of the analysis and findings.

11. Vehicle-to-Grid Integration Using On-Board Inverter

Investment Plan Period	Assignment to Value Chain
3rd Triennial Plan (2018 – 2020)	Distribution

Objective & Scope

The project will assess and evaluate new interconnection requirements, Vehicle-to-Grid (V2G) related technologies and standards, and utility and third-party controls to demonstrate how V2G direct current (V2G-DC) and V2G alternating current (V2G-AC) capable EVs and EV chargers can discharge to the grid and be used to support charging during grid outages. Although vehicle-to-grid interconnection is possible for DC systems, it is not possible for AC systems which comprise a majority of the residential Electric Vehicle Supply Equipment (EVSE) market. Expanding V2G interconnection to include both types of systems would make the technology more accessible to a wider base of ratepayers.

The project will assess and evaluate, in a laboratory environment, the proposed V2G-AC Rule 21 interconnection processes, proposed SAE and UL standards, the function of automaker Original Equipment Manufacturer (OEM) battery/inverter systems to support vehicle-grid integration (VGI) services, and the integration of project 3rd party aggregators with SCE's Grid Management System (GMS)/Distributed Energy Resource Management System (DERMS).

These activities will provide an interconnection pathway by demonstrating functional requirements in the lab. This will allow the interconnection of vehicles with onboard inverters and level 2 AC bidirectional charging systems, unlocking the potential for EVs to provide energy services to the grid. Furthermore, the communications and controls demonstrated in this project will provide a greater understanding of how a utility will be able to interact with EVs and other Distributed Energy Resources (DERs) via cloud-based aggregator platforms connected to DERMS.

Schedule

Q1 2020 – Q2 2026

Project History

Initial work started with V2G-DC, using an emulated Electric Vehicle Supply Equipment (EVSE) connected to an aggregator platform to verify DERMS communications. This first V2G-DC phase successfully demonstrated DERMS-managed control of an EV as a DER. The DERMS used in this phase was a third-party DERMS as SCE DERMS was not ready.

The V2G-AC demonstration followed this, using a different EV architecture and SCE's DERMS instead of a third-party DERMS. Draft standards were leveraged to demonstrate what the interconnection process would look like for vehicles with onboard inverters, in addition to Vehicle-to-Home (V2H) islanding capabilities. The V2G-AC demonstration was completed in early 2025. Findings from the project were compiled and submitted to the relevant standards development bodies.

The second V2G-DC phase of the project expanded on the work from the first V2G-DC phase by introducing a hardware EVSE. This was intended as a replacement for the field demonstration with school buses that was canceled when the school bus vendor dropped out of the project due to lack of technology readiness. Integration issues with the aggregator for the replacement vendor were discovered. The aggregator could not establish all communications requirements with SCE DERMS, i.e., some communications payloads were not exchanged between the aggregator and DERMS. Due to a scheduled DERMS upgrade, it was not possible to remediate these issues during the testing period of the project. Combined with the limited functionality with the supplied unit, only V2H tests were conducted. This second phase was completed in November 2025.

An area not addressed by this project is the interaction with customer needs and preferences. When the project was first scoped to include a field demonstration, the intent was to demonstrate advanced customer and aggregator capabilities, including optimizing charging and discharging based on a customer's required departure time and state of charge while simultaneously supporting grid reliability objectives. While the project was unable to demonstrate these functions, they are critical for customers to participate in utility programs while ensuring their EV battery always has sufficient energy to meet their transportation needs and should be explored in future activities.

2025 Status Update

Accomplishments & Success Stories

- The V2G-AC lab demonstration was completed. A live demo was also conducted at the V2G Forum. This demonstration verified the requirements and processes of UL 1741 SC and SAE J3072, identifying potential shortcomings with the standards.
- The V2G-DC lab demonstration with hardware was completed. Although no DERMS-managed V2G-DC was conducted, it did clarify the behaviors expected from interconnected V2G systems as they transition to and from islanding modes.
- The team compiled and submitted comments to the following standards development groups:
  - Sunspec Alliance IEEE 2030.5 V2G-AC Profile Implementation Guide for SAE J3072
  - IEEE P1547
  - UL 1741 SC
  - Electric Rule 21 OIR (R.25-08-004)

Challenges or Setbacks

- Based on vendor responses during the procurement phases, EVSE vendors typically offer proprietary or third-party-partnered cloud-based management solutions, but these applications are often not Common Smart Inverter Profile (CSIP)-certified aggregators. This project required EVSE vendors to provide CSIP aggregator partners, and many EVSE vendors did not have any partnerships or prior integration with a CSIP aggregator. This was one of many restrictions that limited the number of viable EVSE partners for this project.
- DERMS communications use the IEEE 2030.5-2018 standard as defined by CSIP. IEEE 2030.5-2018 supports discharging limits but lacks the functionality to communicate charging limits. To work around this limitation, the V2G-AC project implemented the discharging limits such that if a discharging limit was dispatched while the EV was charging, it would be interpreted as a charging limit. Charging limits are critical with EV and V2G systems for flexible service connections in capacity-constrained areas and grid reliability programs. IEEE 2030.5-2023, the

latest version of the standard, has added support for scheduled charging limits (e.g., day-ahead) that will need to be included in the latest version of CSIP, which is being developed by IEEE.

- At the time of the V2G-DC hardware demonstration, there were only two car models that were V2G-DC capable and relatively widely available. Compatibility requirements with the EVSE also limited the specific model years that could be used for either vehicle. While a loan agreement with the manufacturer(s) was the ideal path, this was not possible with the time constraints of the project. The team mitigated this by securing multiple vehicles by procuring multiple vehicles (one by renting and another by reserving from the SCE fleet). However, these vehicles could only be retained for a short period of time, so an agreement was made for the EVSE vendor to provide a vehicle as well. This challenge may be lessened as auto OEMs release V2G-capable ISO 15118 vehicles.
- Interoperability issues were discovered between SCE DERMS and the aggregator for the V2G-DC hardware demonstration, even though the aggregator was CSIP certified. SCE did not have sufficient resources to address this issue in a timely manner, so the team elected not to complete aggregator integration.

Key Findings and Lessons Learned

- Despite requiring CSIP certifications from aggregators, there were still issues discovered when testing DERMS-to-aggregator communications. Many issues were related to interpretations of IEEE 2030.5 and CSIP, while others were related to SCE's specific GMS/DERMS implementation, such as the use of IEEE 2030.5 attributes and cybersecurity requirements. Until these standards and technologies mature, interoperability testing between SCE DERMS and all new clients will be required, and clear requirements should be made available.
- The project observed significant voltage drop as measured at the grid side of the EVSE and the internal EV measurement point. In a customer deployment, the proposed UL 1741 SC oversight requirements would cause EVSEs to go to ride-through or must-trip zones prior to the EV reaching these thresholds and thus prevent it from complying with Electric Rule 21 (and SAE J3072) Volt-VAR settings. SAE J3072 does have a "Dynamic Calibration Function" that would enable the EVSE to provide the EV the offset to use based on whether the reference point required is the point of connection of the EV or the Point of Common Coupling at the home (usually the utility meter). The project was unable to demonstrate this functionality, and it should be evaluated for its effectiveness prior to implementation, with the correct functionality input into the standards.
- As the V2G-AC test vehicle used an older intra-vehicle communication technology, it took 5 to 7 minutes for the completion of the SAE J3072 initial communications exchange between the EV and the EVSE that is required for the vehicle to receive the authorization to discharge. While this will be improved by automakers as they design vehicles with V2G capabilities in mind, SAE J3072 should be updated to include a maximum time for the authorization

process. This will ensure consistency in performance regardless of how it is implemented by a manufacturer.

- Upon receiving an authorization to discharge, the EV used in the V2G-AC demonstration would cease to charge and would begin to absorb reactive power. This behavior would be maintained whenever there was no active control command. Ideally, the default behavior for an authorized EV is to continue its previous behavior (charging or idle) until commanded otherwise. Likewise, the EV should not inject or absorb reactive power unless commanded to do so. It is recommended that this default behavior be outlined in SAE J3072.

Customer Benefits

- With new tariffs, V2G can provide bill saving opportunities typically only available for ratepayers with solar generation and battery energy storage. By using their vehicle to supply home air conditioning and lighting loads during the evening hours and then charging their car during the nighttime off-peak hours, a customer can save about $50 per month during the summer.
- CARB's Advanced Clean Cars Rule II requires that by 2035, 100% of new cars and light trucks sold in California will be zero-emission vehicles (ZEVs), including plug-in hybrid electric vehicles (PHEVs). V2G as an additional incentive for customer EV adoption could help California meet the clean car sales requirements and thus help address its climate and air pollution challenges.
- Aggregated V2G could serve as an alternative or supplemental solution in contexts where minor circuit deficiencies/abnormal conditions must be addressed, but normal energy storage does not meet cost-effectiveness expectations. Grid operators could call on these flexible importing/exporting resources and defer costly infrastructure deployments that may only be needed during very limited times of peak demand.

Anticipated RFPs

- There are no anticipated RFPs.

Industry Advancement

- The team presented technical updates/findings at the V2G Forum, the IEEE PES Grid Edge Technologies Conference & Exposition, and the Demand Response & Distributed Energy Resources Forum.
- The team provided regular technical updates in a Technology Advisory Board associated with the project.
- Based on the findings of this project, SCE has submitted input on the following:
  - Sunspec Alliance IEEE 2030.5 V2G-AC Profile Implementation Guide for SAE J3072
  - IEEE P1547
  - UL 1741 SC
  - Electric Rule 21 OIR (R.25-08-004)

12. Wildfire Prevention & Resiliency Technology Demonstration

Investment Plan Period 3rd Triennial Plan (2018 – 2020)	**Assignment to Value Chain** Grid Operation/Market Design
Objective & Scope This project aims to evaluate and demonstrate emerging hardware and software technologies that can significantly advance SCE's ability to prevent, detect, and mitigate wildfires across all voltage levels. While SCE's ongoing Wildfire Mitigation Plan (WMP) focuses on deploying commercially ready solutions, this effort targets the next wave of innovations that show strong commercial promise but require deeper validation in real utility environments. The hardware component of the project focuses on demonstrating enhanced asset inspection data collection combining AI with UAVs (unmanned aerial vehicles) capable of identifying deteriorated asset conditions more efficiently and effectively than current business practices. The AI aims to automate UAV inspection flights for the purpose of taking consistent photography angles while running computer vision detection models in the field to aid the inspector in completing the asset inspection. Additionally, the project will explore sensor capabilities to mount on the UAV to detect issues not seen in the visible light spectrum. By testing these technologies under real-world grid conditions, SCE could assess performance, reliability, and integration pathways before large-scale deployment. In parallel, the software component emphasizes cutting-edge waveform anomaly data analytics and intelligent automation platforms. These tools are designed to enhance situational awareness on soon to fail grid equipment and support operational decision-making that reduce ignition risk and improve system resilience. This capability is expected to help SCE identify precursory indicators of failing grid equipment and hazardous conditions like wire down events in order to take remediation actions. Key deliverables for the software component will include the demonstration of "next-generation" analytics software capabilities using existing substation and distribution telemetry devices to detect leading wildfire indicators. For the hardware component, key deliverables will include demonstrating machine learning software capabilities that improve the quality of aerial inspection images and detect asset damages at the edge.	
Schedule Q4 2021 – Q2 2027	
Project History Building upon earlier analytical and technology-evaluation efforts referenced in prior annual reports, this project aligns with situation awareness activities initiated through SCE's 2018 GS&RP application and subsequent Wildfire Mitigation Plans (WMPs). Those past efforts explored automated image processing, machine learning, artificial intelligence, and early decision-support capabilities to enhance wildfire prevention, asset-management activities, and incipient fault detection. This project continues that progression by demonstrating and appraising promising precommercial technologies aligned with the Joint Investor-Owned Utility (IOU) Framework	

categories of Grid Modernization & Optimization and Cross-Cutting Foundational Strategies & Technologies.

Past efforts for incipient fault detection have demonstrated the ability to detect anomalous conditions in high resolution waveform data associated with failing grid equipment. However, these solutions require one-off sensors to be installed and are siloed from other systems needed to take appropriate remediation. Innovative data collection from existing sensors and combining that data from traditionally disparate systems can expand the capability more broadly across the grid more broadly. The project will demonstrate this concept in a small-scale data platform that will prove the ability to manage and use this sensor data for real-time operations.

The current project advances earlier work by integrating next-generation analytics and decision-support tools into coordinated demonstrations that evaluate how emerging technologies can operate in realistic utility environments. While it does not address full system-wide deployment or long-term scalability, it sets the stage for future questions, such as, how unified, real-time wildfire intelligence systems could combine telemetry analytics and image-based machine learning (ML). Future efforts of building this work could offer ratepayer benefits through improved reliability, enhanced safety, reduced wildfire-related emissions, and more efficient asset-management processes that support grid modernization and electrification.

2025 Status Update

Accomplishments & Success Stories

- *Project Progress & Technical Accomplishments*
    - The team continued advancing next-generation analytics by shifting from static waveform evaluation to preparing for real-time data integration with SCE systems.
    - The team successfully completed the sandbox phase, validating waveform-analytics methods and data structures using historical datasets.
    - Developed Python-based analytics for a Distribution Fault Recorder (DFR) Common Format for Transient Data Exchange (COMTRADE) real-time event-detection flow, enabling near real-time anomaly detection capabilities.
    - Lab Demonstration DFR equipment with hardware-in-the-loop simulated fault events was set up to validate real-time detection and analysis workflows.
    - The platform allowed the team to use the National Labs (third-party)-developed model for event classification and run it directly on the Distribution Waveform Analytics (DWA) platform.
- *Next Phase Grid Data Platform & Integration Readiness*
    - Evaluated alignment between DWA and a separate internal power-quality initiative, expanding potential cross-functional use cases for analytics.
    - Completed decommissioning of the legacy sandbox and initiated planning for a new data platform to support the next demonstration phase.
    - Prepared for the next project phase by defining expanded system requirements needed for real-time ingestion of waveform and sensor data. Positioned the project for the transition to a quality assurance environment capable of supporting more realistic data

integration with required SCE systems (i.e., SCADA - Supervisory Control and Data Acquisition and AMI - Advance Metering Infrastructure).

- *Collaboration & Stakeholder Engagement*
  - Engaged internal partners to align platform capabilities with grid-operations needs and ensure compatibility with future system modernization paths.
  - Identified integration opportunities across teams focused on data architecture, power quality, and digital-grid initiatives to broaden benefits and accelerate adoption.
- *Outlook*
  - Project remains on track to support a competitive solicitation for a real-time analytics platform, planned for release in Q2 2026.
  - Ongoing evaluation will enable a future demonstration environment that supports enhanced anomaly detection, situational awareness, and wildfire-risk monitoring.

Challenges or Setbacks

- The project faced challenges with dedicated IT resources needed to support data-platform administration. The team plans to secure dedicated IT resources in future phases to avoid bottlenecks.
- When the hardware use case reached the procurement stage for integrated system components, SCE determined that none of the potential vendors could meet all three required criteria: (1) providing the needed off the shelf technology, (2) complying National Defense Authorization Act (NDAA) requirements and (3) accepting the EPIC Terms & Conditions. Due to the challenges with the hardware vendors, the team has decided to emphasize the software solutions and de-emphasize the hardware solutions.

Key Findings and Lessons Learned

- Automated image-capture and defect-detection technology was not mature enough for integration into this EPIC project, informing the need to reassess technology readiness levels before initiating future deployment efforts.
- Management of security certificates for edge agents (e.g., MiNiFi) emerged as a key operational lesson, required by Cyber Security to encrypt data transfer, demonstrating the need for streamlined certificate-lifecycle processes to support field-deployed data pipelines and analytics. This lesson showed areas that need to be addressed in the system architecture before moving to a production system.
- Scripting requirements for deploying waveform data parsing and analytics in Apache NiFi, indicating future requirements for the next phase of the data platform. This lesson taught SCE how to effectively parse the sensor data, and areas for improvement before moving to a production system. It also exposed inconsistencies to data quality, specifically nomenclature discrepancy between systems, which should be addressed to enable smooth operation of data pipelines.
- The team learned that protection focused DFR event trigger settings are in most cases not sensitive enough to pick up subtle incipient events. Higher energy incipient events like failing underground cables are detected well but others like loose / failing connectors do not get detected. The team also found cases of too sensitive trigger settings, such as harmonic

distortion, causing over triggering in some areas. Setting the event trigger settings more sensitive then begs a need to have these automated pipelines to analytics in place and working correctly because the volume of data will dramatically increase. Trigger setting changes were not adjusted in the project.

Customer Benefits

- Future efforts to build on this work could offer ratepayer benefits through improved reliability, enhanced safety, reduced wildfire-related impacts, and more efficient asset-management processes that support grid modernization and electrification.
- These benefits would be applicable across SCE’s entire customer base, including low-income communities, by supporting a more resilient and equitable energy system.
- Future benefits from enhanced situational awareness to grid anomalies, customers could expect to see:
    - More timely response to grid outages, especially in cases that historically would be more difficult to detect with traditional protection and monitoring like High Impedance Fault (HIF) events.
    - An elevated act of urgency when conditions are detected that could indicate arcing, which is something SCE previously would have not had visibility into.
    - More equipment being repaired proactively when signs of incipient fault events are detected, resulting in less unplanned outages.
- These customer benefits immediately target communities threatened by high fire risk, where the risk from in-service equipment failures is elevated. However, the capability could spread grid-wide as more sensors get deployed outside HFRA.

Anticipated RFPs

- The project is anticipating kicking off an RFP in Q2 2026. While the previous phase utilized a legacy data platform, demonstrating key components for data engineering and analytic discovery in working with waveform data, this RFP will target a more modern data platform with the intent to demonstrate a full system that could be scaled to production if the demonstration is successful in the quality assurance environment. Since the launch of this project, vendors are now offering more mature solutions targeted at the project objectives.

Industry Advancement

- A power-systems vendor introduced new continuous-waveform streaming and analytics products influenced by an IEEE report, "Synchro-Waveform Measurements and Data Analytics in Power Systems," in *IEEE Power and Energy Society Technical Report*, PES-TR127, December 2024, co-authored by engineers on this project. The vendor’s presentation of these new tools reflects how industry developments are responding to the work underway in this project.
- The SCE team presented this project at the North American SynchroPhasor Initiative (NASPI) & IEEE Synchro-Waveform Joint Webinar, “Synchro-Waveform Data Analytics Architecture and Big Data Platform for Grid Operations and Situational Awareness,” in February 2025.

(3) 2020 – 2025 Investment Plan Projects

1. A2G Operational Efficiencies

Investment Plan Period 1st Quinquennial Plan (2021 – 2025)	**Assignment to Value Chain** Grid Operation/Market Design

Objective & Scope

This program will advance grid modernization through targeted digital tools and analytics that strengthen reliability, enhance public safety, and improve operational efficiency, delivering direct benefits to ratepayers. As specific initiatives are selected and implemented, the program will focus on capabilities that improve situational awareness, streamline operator, and field workflows, and enable faster, more informed decision-making.

These enhancements help reduce outage frequency and duration, lower long-term operating costs, and support a more resilient and cost-effective electric system that provides safer, more reliable service to customers.

Initiative Key Scope Elements

- **Major Event Response Prep System**
  - Design and pilot algorithms for major event response, focusing on resource staging, deployment strategies, and risk reduction awareness.
  - Assess and extract relevant data from Supervisory Control and Data Acquisition (SCADA), weather feeds, asset health databases, and other operational systems.
  - Define the data framework required to enable full production deployment.
  - Translate predictions into actionable plans and resource coordination strategies.
  - Provide dashboard displaying real-time weather, asset risks, and system conditions.
- **Vision Intelligence for Drones Integration**
  - Ingest real-time drone video and telemetry data to detect hazards using AI-based models.
  - Automate incident creation and compliance reporting using Vision Intelligence-driven analytics.
  - Provide live dashboard with map overlays, video feeds, and incident markers.
  - Integrate with Geographic Information Systems (GIS) and asset management systems for spatial accuracy and asset traceability.
- **Logging Assistant**
  - Identify manual and inconsistent steps in current logging workflows.
  - Auto-populate log entries using real-time data from Advanced Metering Infrastructure (AMI), SCADA, Digital Fault Recorders (DFRs), and other sources.
  - Extract structured data from unstructured inputs using large language models.
  - Provide a guided digital interface for operators with real-time validation and tagging.
  - Integrate with existing systems and meter data systems for consistency and completeness.
- **Chatbot Assistant**

- Ingest and index System Operating Bulletins (SOBs) and technical documents into a searchable knowledge base.
- Interpret operational terminology to provide accurate, context-aware responses.
- Offer flexibility to operate standalone or embedded into existing tools.
- Support ongoing updates aligned with the latest procedures and regulatory requirements.

- **Switching Plan Analysis for Scheduling Optimization & Auto Dispatch Enablement**
  - Extract operational steps from Integrated Tools for Outage Analysis (ITOA), SAP, Advanced Distribution Management System (ADMS), emails, and phone logs.
  - Provide real-time information to support scheduling.
  - Incorporate GPS routes and switch-type considerations.
  - Generate reports for data-driven scheduling and continuous improvement.
  - Begin with distribution switching; expand to transmission in future phases.

Establish structured switching data to enable future AI automation.

Schedule

Q4 2025 – Q4 2028

Project History

Grid Operations are increasingly challenged by threats to the system and hazards resulting from climate vulnerabilities, with the need to manage complex, high-volume data streams while maintaining reliability, speed, and accuracy in decision-making. Current workflows across logging, documentation access, outage analysis, crew coordination, incident response, weather impact analysis, and patrol inspections during Public Safety Power Shutoff (PSPS) events are heavily manual, inconsistent, and fragmented resulting in inefficiencies, delayed responses, and underutilized data assets.

The primary objective of this project is to demonstrate a set of AI-based tools that target specific pain points in manual processes, provide additional context where information is lacking, and improve operational efficiency of Grid Operations resources.

2025 Status Update

Accomplishments & Success Stories

- The A2G Operational Efficiencies project launched in early November after a public presentation in late September. After confirming sponsors and baselining the Project Charter, the project team received approval to enter the Planning Stage.

Challenges or Setbacks

- None identified yet as the Team is currently in the Planning phase.

Key Findings and Lessons Learned

- Early engagement with Procurement to understand the RFP process has equipped the project team with an understanding of requirements, timelines, and expectations - enabling a seamless process and allowing the team to proactively identify and mitigate potential risks.

Customer Benefits

- Strategically, the planned initiatives represent a significant opportunity to modernize SCE Grid Operations through intelligent automation, integrated data systems, and advanced analytics. By addressing current inefficiencies and unlocking the value of existing data, the program positions SCE to respond more quickly and effectively to emerging threats and grid conditions. This transformation will:
    - **Increase safety** by enabling faster, more informed decisions during critical events.
    - **Enhance reliability** through improved coordination, predictive insights, and streamlined workflows.
    - **Reduce operational overhead** by minimizing manual processes and optimizing resource utilization.
    - **Strengthen grid resilience** by proactively managing climate-related risks and improving situational awareness.
    - **Improve customer satisfaction** by reducing restoration times and improving customer communication.

  Together, these efforts support the transition to a more agile, data-driven, and resilient grid infrastructure—better equipped to serve communities and adapt to evolving challenges.
- By reducing restoration times, preventing avoidable outages, minimizing unnecessary truck rolls and overtime, and enabling more targeted use of crews and equipment, A2G Operational Efficiencies helps control operating costs while improving reliability and safety outcomes. These efficiencies directly reduce cost pressures passed to customers and support a more resilient electric system.

<u>Anticipated RFPs</u>
- Looking ahead to 2026, anticipated RFP activity would likely focus on products, equipment, and services that support continued operational modernization across grid operations.
- This may include enterprise software solutions that enable operator assistance, workflow automation, and improved access to operational information; analytics and visualization tools that support planning, forecasting, and major event preparedness; and digital inspection and monitoring technologies that enhance field and asset visibility.
- Supporting equipment may include on premises computing and data infrastructure required to securely operate these capabilities within operational environments.
- In addition, associated professional services are expected to cover system integration, configuration, cybersecurity and regulatory compliance, pilot to production scaling, workforce training, and ongoing operational support to ensure these solutions are deployed safely, reliably, and at scale.

<u>Industry Advancement</u>
- Once the project is underway, SCE may share selected learnings with the broader utility and grid modernization community through controlled, nonoperational channels. This may include participation in industry forums and peer utility discussions, conference presentations, and SCE approved case studies or white papers that highlight high level architecture patterns, human in the loop AI practices, and realized operational benefits.

• Any information shared will focus on lessons learned and best practices rather than sensitive data, system details, or proprietary models, and will follow SCE's established cybersecurity, regulatory, and communications governance processes.

2. Communication Assisted Protection Technologies for Inverter-based Networks (CAPTIN)

Investment Plan Period 1st Quinquennial Plan (2021 – 2025)	**Assignment to Value Chain** Distribution
Objective & Scope The Communication Assisted Protection Technologies for Inverter-based Networks (CAPTIN) project will evaluate new communication assisted protection technologies for systems with high penetration of inverter-based resources (IBRs). Traditional protection schemes for distribution systems may have reduced reliability in regions significantly impacted by IBRs; therefore, new protection schemes must be evaluated to ensure reliability of future systems when an even greater number of IBRs are expected to be grid-connected. This project will demonstrate new technology in a lab environment to evaluate the feasibility and design of a proposed system architecture that can ensure protection for the future grid will maintain reliability when a greater presence of IBRs is realized. The proposed system will utilize communication between distribution system protection devices to enhance decision-making in protection operations. Today, distribution protection devices rely on pre-configured settings based on a deterministic fault current. The proposed system will implement communication-based protection schemes that can ensure fault detection under a greater variety of system conditions. SCE customers will benefit from improved reliability and safety with expected reductions in Customer Average Interruption Duration Index (CAIDI) and Customer Minutes of Interruption (CMI). Communication Assisted Protection will ensure that faults can be detected and interrupted even in areas with high penetration of IBRs. The ability to reliably protect against faults can help prevent equipment damage and safety risks. The communication assisted protection scheme may increase in SCE's ability to accept and approve IBR interconnection requests, and customers can benefit from a higher renewable energy resource mix.	
Schedule Q4 2025 – Q2 2028	
Project History This project builds on previous findings from the EPIC 3 project, Distributed Energy Resources Dynamics Integration Demonstration (SCE-GT-18-0019), which found that for certain levels of DER penetration on distribution systems, traditional protection schemes may not be sufficient for detecting faults. This project will focus on this topic and identify new protection schemes to mitigate challenges with high penetration of inverter-based resources (IBRs) like protection mis-coordination and mis-operation due to bi-directional power flow and reduced fault duty. In	

addition to fault protection, this project will evaluate how the communication assisted protection scheme can detect that can occur on distribution systems with high IBR penetration, like unintentional islanding. The outcome of this project can result in improving reliability on distribution systems with these characteristics.
2025 Status Update Accomplishment & Success Stories • The team presented this project at the 2025 Smart Grids USA conference discussing the proposed technology and the ways that communication assisted protection can improve reliability for distribution systems with high IBR penetration. • The Project was publicly announced in late September 2025 and officially launched in early November of 2025 after confirming sponsors and baselining the Project Charter. • The team commenced official project planning and plans to enter the Execution Phase in Q1 2026. Challenges or Setbacks • No current challenges or setbacks have been identified. Key Findings and Lessons Learned • This year, the team has identified gaps in the traditional method of distribution system protection schemes, which primarily rely on overcurrent fault detection. In systems with high penetration of inverter-based resources, traditional protection schemes may be insufficient for detecting and isolating faults. Customer Benefits • The technology proposed in CAPTIN can result in reduced customer minutes of interruption (CMI) and customer average interruption duration index (CAIDI). Anticipated RFPs • The project anticipates issuing an RFP and selecting a vendor to procure distribution protection devices and perform implementation. Industry Advancement • The team presented at the 2025 Smart Grids USA conference to share the objectives and concept of this project.

3. Flexible Alternating Current System (FACS)

Investment Plan Period 1st Quinquennial Plan (2021 – 2025)	**Assignment to Value Chain** Distribution
Objective & Scope	

This project aims to demonstrate how Power Quality Conditioners (PQCs) can cost-effectively integrate renewable resources and meet additional load requirements compared to traditional grid reinforcement infrastructure upgrades, which in some cases can be more expensive. By monitoring and regulating voltage, reactive power, and power flow, PQCs enhance grid utilization and resilience without the need for costly grid reinforcement. Ultimately, this will enhance grid reliability, increase customer power quality, and defer costly upgrades in select cases.

Schedule

Q2 2024 – Q3 2029

Project History

Building on SCE's prior work in distribution system analytics, Distributed Energy Resource (DER) hosting capacity studies, and earlier EPIC investments in grid sensing and power-electronics pilots, this project advances the utility's ability to manage voltage and power quality dynamically. Earlier efforts (summarized in the 2023 and 2024 Annual Reports) established the data, modeling, and planning foundations that made it possible to develop the TWA (Territory Wide Assessment) 2.0 siting tool, refine STATCOM sizing, and launch a targeted Request for Proposal (RFP). By moving from conceptual analysis to actionable deployment planning, the project strengthens the link between previous research and real-world grid needs, particularly in circuits experiencing DER-driven variability and electrification growth.

The current project pushes this work forward by creating standardized processes, procurement pathways, and engineering practices for PQC deployment, but it remains limited to a single demonstration site and focuses primarily on reactive power solutions. Future efforts could explore how PQCs coordinate with other grid devices, how they perform under high EV-charging scenarios, and how a portfolio of power-electronics solutions could defer upgrades more broadly. These next steps could deliver substantial ratepayer benefits such as improved reliability, reduced equipment stress, avoided emissions through greater DER integration, and lower long-term costs by deferring traditional capacity investments.

2025 Status Update

<u>Accomplishments & Success Stories</u>

- The project advances SCE's use of power-electronics-based grid support by deploying one Power Quality Conditioner within SCE's distribution system to mitigate the voltage, power factor, harmonic, and flicker issues.
- The team completed the TWA 2.0 siting workflow to pinpoint the circuit in need of this technology, refined STATCOM sizing to a 1-4 MVAR range, and launched a competitive RFP. After some delays, the site and sizing study is also set to launch March 2026.
- The team has evaluated multiple candidates for the STATCOM RFP, assessed technical feasibility, and incorporated updated cybersecurity and testing requirements into the deployment approach. Internal partners across Planning, Grid Operations, Cybersecurity, Safety and Procurement have collaborated to align on deployment strategy.
- The team continues to evaluate vendor proposals and integration requirements (RFP was launched January 2026 with 2/6 vendors showing interest) to ensure the selected technology can meet SCE's power quality and reliability objectives.

- The project was also presented at the IEEE EESAT 2026 Conference and DTECH 2026, highlighting SCE's data-driven approach to prioritizing PQC placement in large-scale distribution systems.

<u>Challenges or Setbacks</u>

- The project experienced delays in launching the site and sizing study due to challenges in verifying vendors met eligibility and risk mitigation requirements, which slowed progress toward selecting the final deployment location and finalized size of the STATCOM needed. The team mitigated this by increasing cross-functional alignment and adjusting schedules to keep critical-path activities moving. Additional barriers (such as permitting, interconnection requirements, and site-specific environmental considerations) may further affect implementation and will require early engagement with the appropriate internal groups to avoid future delays.
- A significant external challenge is the current transformer supply chain: lead times of up to 18 months could delay the procurement and installation of the step-up transformer (if required) for the STATCOM. The team plans to address this by initiating procurement as early as possible, exploring alternative sourcing strategies and evaluating solutions that do not require a step-up transformer.

<u>Key Findings and Lessons Learned</u>

- Through internal and external discussions with our stakeholders, the team identified several eligible vendors who provide STATCOMs in the 1-4MVAR size range and confirmed targeted deployments in this range can reduce voltage excursions and enhance power quality for sensitive customers.

<u>Customer Benefits</u>

- The team identified customer value by demonstrating how a 12 kV D-STATCOM can improve voltage stability, increase DER hosting capacity, and support additional EV charging without requiring immediate distribution upgrades. Project activities confirmed that targeted deployments in the 1-4 MVAR range can reduce voltage excursions and enhance power quality for sensitive customers.
- Industry experience shows that devices like D-STATCOMs can defer costly distribution upgrades by providing fast, dynamic voltage support and reducing equipment stress. As SCE completes the site and sizing study, the project will quantify these benefits for the selected circuit and evaluate how they could scale across the system. The results will inform future deployment strategies, support Distribution Voltage Control (DVC) efforts, and guide planning for circuits in disadvantaged and low-income communities. By enabling more DERs and supporting transportation electrification, the project demonstrates clear ratepayer benefits and contributes to California's clean-energy and climate goals.

<u>Anticipated RFPs</u>

• An RFP was launched January 2026 with responses due February 20th. This is expected to be the only RFP involved in this project and constitutes the majority of material/services required to be purchased. <u>Industry Advancement</u> • The team presented the project in DTECH 2026 San Diego to share project findings with the industry. • The team advanced industry knowledge by publishing the peer-reviewed paper *"A Constrained and Data-Driven Approach for Prioritizing the Placement of Power Quality Conditioners in Large-Scale Distribution Systems"* in the IEEE PES proceedings and presenting project findings at the IEEE EESAT 2026 Conference. • The project will contribute to industry discussions on interoperability and power-electronics integration. • On the tech-transfer side, the project may inform future SCE standards, site-scoping tools, engineering design practices, and O&M expectations for power-electronics assets. The project findings can guide future PQC deployment and support broader adoption of voltage-support technologies across the distribution system.

4. Industrial Demand Flexibility Enabling Distribution Grid Autonomous Resilience (IDF-EDGAR)

Investment Plan Period	**Assignment to Value Chain**
1st Quinquennial Plan (2021 – 2025)	Demand Side Management
Objective & Scope The objective of the IDF-EDGAR project is to enable SCE's Distributed Energy Resource Management System (DERMS) to monitor and control customer-owned Distributed Energy Resources (DERs), demonstrate DER orchestration to obtain distribution grid load flexibility, demonstrate dynamic pricing at an industrial customer, and demonstrate a CSIP IEEE 2030.5 (or direct DERMS command) based DER integration. The learnings from this can be used to inform development of internal standards, operating procedures, and DERMS functionality. The demonstrations will inform future dynamic pricing tariffs for industrial customers to participate in while saving them money on their bill as well as utilizing DERMS to shift loading to support local grid needs. The combination of DERMS and dynamic pricing will have a significant impact on enabling demand flexibility and load shifting, which will benefit ratepayers by freeing up loading constraints during peak times.	
Schedule Q4 2025 – Q4 2027	
Project History SCE customers are electrifying faster than ever and as a result, forecasts for electric demand are increasing across customers. Commercial and industrial customers already consume significantly more energy than other customer types, and as they electrify, the scale of their use will only	

continue to grow. However, this also presents an opportunity for grid relief as small changes in their energy use can significantly affect grid demand.

As these customers are electrifying, their need for resiliency is increasing, leading them to adopt additional technologies to provide this resiliency. The adoption of on-site generation and storage create additional flexibility for these customers when they are not using these resources for resiliency purposes.

Industrial demand flexibility, buoyed by electrification and resiliency technology adoption, is critical to stabilize the grid, reduce operational costs, and improve reliability as renewable energy sources introduce more variability. By enabling industrial loads to respond dynamically to grid conditions, SCE can better manage peak demand, avoid costly infrastructure upgrades, and enhance resilience during outages or emergencies while improving affordability.

As traditional generation plants retire, and their inherent inertial characteristics are replaced by inverter-based generation, SCE's transmission and distribution system dynamics will need new tools and techniques to maintain grid stability. High Distributed Energy Resources (DER) penetration provides new, clean energy resource potential, but requires reliable and rugged communication with Front-Of-The-Meter (FTM) DERs, aggregators and Distributed Energy Resources Management (DERM) system, to help manage the operation of these DERs on a distribution power grid.

2025 Status Update

Accomplishments & Success Stories

- The project team has met with internal partners to discuss the local sub-Transmission system needs as well as the status of dynamic pricing with large industrial customers. Both discussions have helped shape the deliverables and project scope through the ideation and planning phase of the project.
- The project team has also met with external partners to discuss the customer plant needs, demand flexibility, and simulation models to help develop project scope.

Challenges or Setbacks

- The project faced a substantial issue in not having a budget to deploy a physical energy storage system at the customer's site. The team mitigated this issue by proposing to demonstrate the benefit of the system through the modeling and simulation phase of the project.

Key Findings and Lessons Learned

- Through internal discussions with our stakeholders, the team learned that not many customers are on the dynamic pricing tariff, nor do they have an easy ability to ingest the 24-hour day ahead schedule. This helped shape one of the deliverables to be a controller that could receive the schedule from SCE and implement load shifting at the plants, thus helping the local grid and saving the customer money on their rates.

- Through external stakeholder discussions, the team learned that industrial customers could upgrade their facilities to enable more demand flexibility.

Customer Benefits

- The team identified potential benefits to industrial customers through utilizing dynamic rates.
- Through this project, the team will be able to quantify the number of kW in peak demand reduction through DERMS demand flexibility.
- The project will increase customer interconnection on circuits with demand flexibility.

Anticipated RFPs

- Customer Controller (EMS)

Industry Advancement

- The project will develop standards and guides on customers utilizing dynamic rates with a controller.
- The project will develop guidelines on utilizing DERMS with customer dynamic rates to provide the most benefit for customers and the grid.

5. Local Optimization & Grid Edge Management Systems (LO-GEMS)

Investment Plan Period 1st Quinquennial Plan (2021 – 2025)	**Assignment to Value Chain** Demand Side Management

Objective & Scope

This project will demonstrate in the laboratory and field how next generation Advanced Metering Infrastructure (AMI) hardware (AMI 2.0), platform, and control systems together with aggregation optimization platforms, could advance SCE's AMI, Distributed Energy Resources Management System (DERMS), and Demand Flexibility Management System (DFMS) platforms ability to interface, integrate and orchestrate customer Distributed Energy Resources (DERs) and loads (Electric Vehicle (EVs), Electric Vehicle Supply Equipment (EVSEs), AC systems, etc.). A primary focus will be to increase customer benefits (such as avoiding panel upgrades or customer energy cost reduction) and provide edge flexibility information to SCE Grid Management System (GMS) platforms to maximize grid system capacity and ensure reliability.

This project improves how SCE and customers can manage and optimize energy use behind the meter by combining smart meters' capabilities, close to real-time data, customer DERs with monitoring and control capabilities, and aggregation functions for the following purposes:

- **Behind the meter load management**
  - This effort will help to avoid a customer panel upgrade caused by EVSE installation or easier home charger installations.
  - Customer-focused and grid edge continuous optimization.
  - Integrating grid edge communications with customer DERs/loads.

- **Dynamic management of a capacity constraint**
  - This effort will enable the utility to support customers with EV charging planning and reduce their energy costs.
  - Monitoring and enabling customer DERs or load management.
  - Demand flexibility capability and integration with AMI/DERMS platforms.
  - Real-time visibility and communication with EVSE and EV charging to provide more flexibility and capacity constraint management.
  - Allows behind-the-meter resources to be dispatched by grid management systems, increasing grid reliability.

Schedule

Q4 2025 – Q2 2028

Project History

First generation AMI systems are reaching end of life, coupled with limited integration and analytical capabilities at meters at home level, are limiting the grid edge enhancements and unable to provide sufficient data from edge, as needed for modern analysis.

Grid edge advanced meters, communication protocols, control systems, standard integration with customer home DERs along with local loads (EVs, EVSEs, AC systems, etc.), edge DER generation management and optimization functions, are needed to extract more benefits out of the system, extend distribution assets life, provide grid resiliency, enable grid edge analytics and deliver real-time visibility to central management systems. This project, together with the EPIC 4 project Stability Improvement with DERs (SIDER), will enable SCE to make more informed decisions that enhance distribution grid reliability and deliver greater benefits to EV-owning customers.

This project aims to demonstrate advance capabilities for behind the meter (BTM) load management and optimization using advanced metering, next generation integrated controls and applications (including AMI platform and SCE DERMS), together with aggregation platforms with the customer DERs integration and optimization functions and focused on local service areas, distribution grid benefits and balancing customer needs and flexibility based on grid's real-time and projected characteristics.

2025 Status Update

<u>Accomplishments & Success Stories</u>

- The team presented the project at EPIC public workshop in September 2025.
- The project's first draft of technical requirements has been developed.
- The project execution outline has been completed.
- The team developed the preliminary system architecture and its integration approach with edge devices.

<u>Challenges or Setbacks</u>

- The Team has not yet identified challenges or setbacks.

<u>Key Findings and Lessons Learned</u> • The Team is still planning the project. <u>Customer Benefits</u> • **Reduced electricity costs:** Visibility into load characteristics and rates and tools to manage them. • **Ability to connect and electrify more quickly:** Controls allowing demand management and dynamic allocation for EV charging, reducing upgrade costs which can be thousands of dollars and managing grid constraints. • **Added resiliency:** Integrated tools and platform for managing outages and islanding. <u>Anticipated RFPs</u> • RFP for an EVSE with the ability to communicate with utility meter. • RFP for an IEEE 2030.5 gateway to translate from 2030.5 to EVSE-compatible communication protocol. <u>Industry Advancement</u> • **Industry collaboration and innovation:** The project team has initiated technical discussions with multiple EVSE manufacturers to understand current capabilities, identify enhancement opportunities, and explore how this demonstration can enable new functionalities that deliver added customer value. • **Secure integration and cybersecurity leadership:** Recognizing secure communications as critical for integrating EVSEs with AMI meters and utility grid management systems, the project team is working closely with cybersecurity teams to evaluate risks and recommend potential security enhancements. • **Standards engagement and industry knowledge sharing:** The project team actively collaborates with industry standards (e.g., IEEE 2030.5) and plans to present at upcoming industry conferences (e.g., DistribuTECH and IEEE forums) to share project lessons learned, insights, and outcomes with the broader industry.

6. ML-Augmented Digital Simulation (MAD-S)

Investment Plan Period	**Assignment to Value Chain**
1st Quinquennial Plan (2021 – 2025)	Grid Operation/Market Design
Objective & Scope This project is important to SCE because it modernizes how substation and distribution work is planned, validated, and delivered reducing safety risk, cost, and schedule uncertainty while improving engineering quality. Today’s workflows rely heavily on manual job walks, fragmented drawings, and disconnected datasets, which drive repeated site visits, rework, and delays that ultimately increase costs borne by ratepayers.	

By digitizing and standardizing these workflows, the project enables safer remote assessments, earlier risk detection, and more consistent, scalable engineering decisions. The resulting efficiencies translate directly into lower project delivery costs, reduced rework, improved reliability, and better value for ratepayers.

To achieve this outcome, the project establishes an integrated digital engineering pipeline that automates the acquisition, modeling, analysis, and visualization of substation and distribution assets. This includes ingesting Light Detection and Ranging (LiDAR) and scan data, generating accurate 3D models, directly interfacing with structural and electrical analysis tools, and enabling multiuser virtual validation within a shared environment. These technical capabilities replace manual, siloed processes with a repeatable and scalable approach that supports circuit level assessments across multiple substations.

The solution will include the following major advancements:

- Automated LiDAR-Driven Data Extraction
- Direct LiDAR-to-Pole-Loading Engine Integration
- Unified Digital Twin Environment
- Circuit-Scale Automated Structural Analysis
- High-Fidelity Virtual Job Walks
- Automated 3D Modeling Pipeline
- Embedded Scan-Point & 3D Photo Integration
- AI-Driven Automated Report Generation
- Automated Safety & Risk Detection
- Scalable Architecture for Multi-Substation Expansion

Schedule

Q2 2024 – Q3 2027

Project History

The MAD-S project extends the Grid Digitalization Program's efforts to improve job walk efficiency, asset accuracy, and structural assessments through digital twin technologies. Past processes such as manual inspections, fragmented asset data, and non-scalable pole loading methods highlighted the need for a unified and automated approach. Earlier EPIC 3 projects including Wildfire Prevention & Resiliency Technologies (WP&RT), GT-19-0004, Advanced Technology for Field Safety (ATFS), GT-18-0002, and several machine learning pilots further showed that although useful, these efforts operated in silos and required custom data pipelines, reinforcing the need for an integrated platform. SCE capital projects like SPEED and GCM moved this forward but did not fully support the expanding set of applications.

MAD-S addresses these gaps by demonstrating core capabilities in a Quality Assurance (QA) environment using LiDAR and production-quality asset records, though the demonstration project is intentionally limited to two substations and one circuit and does not provide enterprise-wide integration or continuous data refresh.

Looking ahead, expanding automated LiDAR-based structural analysis and digital twin technologies across the full grid could support continuous monitoring and predictive risk assessment. Scaling these capabilities would provide significant ratepayer benefits, including improved safety through reduced field exposure, better reliability by identifying structural or clearance issues early, lower operational costs by reducing repeat site inspections and reactive maintenance, and reduced emissions from fewer vehicle trips.

2025 Status Update

Accomplishments & Success Stories

- From Q2 to Q3 2025, the team collaborated with internal partners to assess a range of potential use cases, analyzing supporting data to determine associated benefits and costs, and ultimately select options that would deliver the best value for ratepayers.
- After the completion of SCE's larger Grid Digitization internal Request for Information (RFI) in Q2, 2025, the team evaluated a list of vendors and their capabilities to identify vendors who were suitable for the use cases identified for this project.
- In Q3-Q4, 2025, the project team purchased a 3D LiDAR scanner, Graphics Processing Units (GPUs), and supporting integrating infrastructure.
- In Q4 2025, the engineering team initiated scanning the applicable SCE substation assets to collect 3D LiDAR data.
- In Q4 2025, the project team completed the project overview and high-level Business Requirements Document (BRD).

Challenges or Setbacks

- Vendors faced delays signing the EPIC Terms & Conditions due to concerns about creating new Intellectual Property (IP) for software customization, which further slowed acceptance of SCE's contractual requirements.
- The Business Requirements Documents contained sensitive use-case data, limiting the information that could be shared with the vendor and causing early procurement delays.
- To address core hardware shortages, the team decided to place orders for long-lead hardware immediately after the project execution phase began, reducing the risk of future schedule delays.

Key Findings and Lessons Learned

- A use case is most likely to succeed when the required hardware and infrastructure are available, accurate data can be collected, features are well-defined through user stories, the IT architecture is properly established, procurement coordination is timely, and the selected vendor has the capability to integrate and deliver the project scope.

Customer Benefits

- By enabling earlier identification of high-risk assets and reducing reliance on reactive, emergency-driven field work, the project helps prevent safety incidents, unplanned outages, and equipment failures that directly impact customers. Fewer emergency repairs and outages improve service continuity for end users, particularly during extreme weather and high-risk operating conditions.

- Streamlined planning and virtual validation shorten project timelines, enabling critical grid upgrades such as reliability, wildfire mitigation, and DER-enabling investments to be delivered sooner. This accelerates customer access to a safer, more resilient, and more flexible electric system.
- The reduction in repeated site visits, rework, and late-stage design changes lowers overall project delivery costs. These avoided costs ultimately benefit ratepayers by reducing capital overruns, minimizing the need for emergency construction, and deferring or avoiding unnecessary infrastructure upgrades.
- While the current deployment is limited in scope, the project demonstration objectives are expected to benefit multiple SCE internal Partners with developing a full digital twin solution envisioned to ensure that the architecture is robust, consistent, and aligned with enterprise standards supporting seamless integration, scalability, and long-term sustainability.
- This technology will benefit the following users within SCE by enhancing their workflows, improving data accuracy, and enabling smarter decision-making.

Anticipated RFPs

- Looking ahead to 2026, project team may explore RFPs in select, capability-based areas, such as digital twin platforms, automated LiDAR and scan-data processing, engineering analytics and simulation integration, AI-assisted reporting, and scalable IT infrastructure.

Industry Advancement

- The project team has initiated technical discussions with multiple vendors providing Digital Twin solutions to understand technology level readiness, identify enhancement opportunities, and explore how this demonstration can enable new functionalities that deliver added customer value.
- The project team will collaborate with industry standards and plans to present at upcoming industry conferences (e.g., DistribuTECH and IEEE forums) to share project lessons learned, insights, and outcomes with the broader industry.

7. Quantum Networking

Investment Plan Period	**Assignment to Value Chain**
1st Quinquennial Plan (2021 – 2025)	Grid Operation/Market Design

Objective & Scope

Faced with the possibility of advanced decryption capabilities brought on by Quantum Computers, SCE is seeking to identify means to resist cyber-attacks. This project will validate the commercial application of utilizing quantum mechanics-based encryption protocols to generate and distribute encryption keys over SCE's dark fiber network (I.e., Quantum Key Distribution).

These quantum-enhanced security measures will protect the grid from cyber threats, helping ensure the security and reliability of the grid.

The project will deploy two or more quantum-secured nodes for testing the transmission and receiving of test data over SCE-owned dark fiber. The demonstration will test the feasibility of securing data in the event that Q-day occurs, where quantum computers can easily decrypt modern encryption methods. If proven to be successful, additional steps will be taken to add quantum networks to SCE's networks to harden our network infrastructure.
Schedule Q2 2024 – Q4 2028
Project History Originally this project was submitted as part of a national lab request to the DOE. At that time, the DOE response was that, as described, the project was a demonstration of the technology, not research, and the funding opportunity for the national lab was for research. Due to the description as a technology demonstration by the DOE and the interest within SCE, the project was then examined for its fit into SCE's EPIC 4 plans. This will be one of the first instances of the application of Quantum Networking technology outside of the national lab environments. This project is an EPIC 4 project in the SCE identified T&D Foundational Technology: Ultra Low Latency Communication investigation area. While there are other proposed methods that may mitigate risk Quantum Computing has on cyber security, this project seeks only to explore the viability of using the Quantum Key Distribution approach and no other Post-Quantum Computing mitigations.
2025 Status Update <u>Accomplishments & Success Stories</u> • As discussed in the previous 2024 Annual Report, the team presented at the UTC conference in June 2025 and received positive actionable feedback and questions from the conference attendees. • The team identified the need to launch a competitive bid for the primary portion of the work implementation and launched an RFI in 2025. The team collected learnings from four responders and is incorporating learnings in preparation to launch an RFP. • The team has removed the training goals mentioned in the 2024 report from scope. • Depending on the specific selected technology, the project team may not pursue resiliency against GPS spoofing attacks and instead prioritize the core Quantum Key Distribution technology. <u>Challenges or Setbacks</u> • The project faced a challenge with identifying adequate subject matter expertise internally or from industry regarding Quantum Key Distribution technology, which was necessary to write and evaluate a competitive bid. This delayed the RFP launch; however, the project team expects to launch this RFP in 2026. <u>Key Findings and Lessons Learned</u> • Through internal and external discussions with our stakeholders, the team learned that there are many new entrants to the field of Quantum Encryption; however, the field of responders

who responded to the RFI was significantly lower. While the project team launched the RFI and included eighteen vendors advertising similar capabilities, only four responded, which may suggest the technology is still not commercially mature. <u>Customer Benefits</u> • The primary customer benefit is the reduction of the vulnerability to cybersecurity attacks if the technology proves out and is implemented. • The primary utility benefit is the hardening of SCE's telecommunication infrastructure to some cybersecurity attacks. • If the technology is proven successful, the evaluation will be made as to the deployment to the SCE Grid Communications infrastructure. <u>Anticipated RFPs</u> • The project team expects to launch an RFP for the core technology in Q2 2026. <u>Industry Advancement</u> • As discussed in the previous 2024 Annual Report, the team presented at the UTC conference in June 2025 and received positive actionable feedback and questions from the conference attendees. • Additional learnings will be presented in various public forms as they become available.

8. Stability Improvement with DERs (SIDER)

Investment Plan Period 1st Quinquennial Plan (2021 – 2025)	**Assignment to Value Chain** Demand Side Management
Objective & Scope Stability and Flexibility Improvement with DERs (SIDER) is an EPIC 4 funded technology demonstration project that will integrate multiple third-party aggregators and Distributed Energy Resources (DERs) with SCE's Distributed Energy Resource Management Systems (DERMS), establish the CSIP IEEE 2030.5 communication with aggregators, demonstrate the data exchange and dispatching commands to Electric Vehicles (EVs) and other types of DERs through aggregators or site gateways. This project will help SCE analyze and assess the reliability and availability of aggregators and DERs to support distribution load management. It will also enable SCE to safely and reliably maximize throughput on existing infrastructure, helping improve asset lifetime with managing the EV charging loads at distribution service transformer level, which will ultimately improve ratepayer affordability. In addition, the project will empower customers to better manage their energy costs by supporting greater choices, flexibility in how they use and control their energy and helping improve affordability.	
Project Schedule Q2 2024 – Q3 2028	

Project History

DERs are growing quickly on power systems, providing utilities with new ways to enhance distribution grid operations, and planning to support safety and reliability objectives while enhancing customer value and supporting greenhouse gas reduction. Using new tools such as DERMS, utilities can leverage the flexibility of demand-side energy resources and effectively manage a variety of DERs, both individually and in aggregate.

The SIDER project team evaluated various types of DERs and assessed their potential impact on distribution circuits, as well as the importance of visibility and data exchange with customer-owned DERs. After several months of detailed analysis and discussions with internal stakeholders, the team decided to focus on EVs within SCE's service territory. The objective is to understand how EVs can be aggregated, monitored, and managed to participate in distribution load management events, particularly in areas where high EV load penetration may affect the lifetime and performance of distribution assets. Ultimately, this effort is expected to benefit customers by reducing the cost of EV charging equipment and enabling energy cost savings.

SIDER Project Milestones and Achievements

The SIDER project successfully achieved multiple milestones, spanning architecture design, technical specification development, vendor engagement, and procurement activities. These efforts were informed by extensive collaboration with industry vendors and culminated in vendor selection and contracting activities. Key accomplishments include the following:

- **Vendor Engagement and Identification**
  Engaged and identified fifteen (15) third party aggregator vendors with aggregation functionality and edge-based analysis and optimization capabilities.
- **OEM Collaboration**
  Collaborated with six (6) electric vehicle (EV) original equipment manufacturers (OEMs) possessing V1G and bidirectional V2G capabilities to inform and support the project's field demonstration planning.
- **RFP Execution and Technical Evaluation**
  Conducted a Request for Proposals (RFP) process involving 15 third-party aggregator vendors. Performed detailed technical evaluations of vendors' aggregation platforms, CSIP IEEE 2030.5 communication capabilities, and DERMS integration readiness.
- **Vendor Down-Selection and Customer Onboarding Planning**
  Worked with six (6) selected aggregator vendors to develop procurement strategies, contracting plans, and customer onboarding logistics. These efforts support participation of up to 1,000 EV owners for V1G demonstrations and 100 EV owners for V2G demonstrations over the project lifecycle.
- **Use Case and Scope Development**
  Developed defined use cases and a high-level scope of work for V1G and V2G testing in coordination with aggregator vendors and EV manufacturers.

Key Vendor Achievements Related to Customer DER Integration

Through discussions with participating vendors, the team identified that the majority of aggregator vendors initially lacked CSIP IEEE 2030.5 certification. This project encouraged vendors to become familiar with DERMS integration requirements, develop or integrate IEEE 2030.5 compliant communication interfaces, and pursue the required certifications. SCE's cybersecurity team shared the DERMS integration cybersecurity requirements and worked with the vendors to help them identify gaps and strengthen their cloud-based platforms, ensuring that EV owner customer data is protected as expected. During the cybersecurity assessment, SCE's cybersecurity team also provided multiple enhancement recommendations to support vendors in strengthening their platforms and providing customers with a more reliable and secure solution. Additionally, throughout SCE's SIDER team discussions with multiple vendors and EV OEMs, vendors communicated that customer onboarding incentives or commercial support - potentially funded through utility programs or external sources like the California Energy Commission (CEC) - are needed to encourage customer (EV owners) participation. They also underscored that regulatory backing for such incentives is essential to ensure program affordability, equity, and maximizing adoption. Finally, vendors were requested to incorporate Disadvantaged and Vulnerable Communities (DVCs) and low-income areas into their field demonstration planning to ensure equitable customer benefits. These benefits include access to EV charging infrastructure and opportunities for reduced EV charging costs during the project demonstrations.
2025 Status Update Accomplishments & Success Stories • The project team coordinated with the DER Management System (DERMS) team to develop processes to onboard aggregators into DERMS. • The team also met with internal Partners to plan how aggregator-contracted customers can be recruited into SIDER and similar DERMS programs. • The team conducted an RFP process with fifteen (15) aggregator vendors and down selected six (6) vendors to integrate with SCE's DERMS with CISP IEEE 2030.5 communication. • The team continues to evaluate multiple aggregator platforms' performance, reliability, and ability to onboard large amount of EVs (1000 EVs per vendor). • The team presented this project at a conference (CEC EPIC Symposium- Sacramento October 2025) discussing CPUC 2025 affordability conference and presented how this project potentially can provide benefits to customers. Challenges or Setbacks • Throughout SCE's SIDER team discussions with multiple vendors and EV OEMs, vendors communicated that customer onboarding incentives or commercial support - potentially funded through utility programs or external sources like the California Energy Commission (CEC) - are needed to encourage customer (EV owners) participation.

- They also underscored that regulatory backing for such incentives is essential to ensure program affordability, equity, and maximizing adoption.

Key Findings and Lessons Learned

- Most existing aggregator vendors did not fully comply with CSIP IEEE 2030.5 certification requirements. The SIDER project encouraged these vendors to complete internal testing and improve their readiness for utility DERMS system integration.
- During the RFP evaluation process, utility cybersecurity requirements should be clearly communicated, and vendors' cybersecurity practices must be reviewed and aligned to ensure compliance.
- Well-defined RFP technical documentation - including clear requirements, detailed Statements of Work (SOW), and utility DERMS interface standards - plays a critical role in enabling seamless integration between DERMS and aggregator cloud-based systems.
- Aggregator vendors indicated a need for greater utility support to more effectively onboard and recruit EV-owning customers.
- Offering customer incentives can significantly increase participation in energy management programs; however, such incentives may result in costs of approximately \$100–\$200 per customer for aggregator companies.

Customer Benefits

- The team identified new sources of customer value, including how this technology and effort could benefit customers by reducing the cost of EV charging equipment and enabling energy cost savings.

Anticipated RFPs

- The SIDER project team conducted an RFP process with fifteen (15) aggregator vendors, down selected six (6) vendors to integrate with SCE's DERMS with CISP IEEE 2030.5 communication.
- Planning for CSIP IEEE 2030.5 gateway equipment for the testing of the 6 selected vendors.

Industry Advancement

- The project team has initiated technical discussions with multiple Aggregator vendors, to understand current capabilities, identify EV charge management options to facilitate processes to ease customer participation and assist customers to manage/reduce the energy bills, and explore how this demonstration can enable new functionalities that deliver added customer value.
- The SIDER project team presented the lessons learned, challenges and outcomes of interacting with EV OEM and aggregators companies with peer utilities, EPIC stakeholder workshop, and CEC EPIC Symposium- Sacramento October 2025.
- The project team actively collaborates with industry standards (e.g., IEEE 2030.5) and plans to present at upcoming industry conferences (e.g., DistribuTECH and IEEE forums) to share project lessons learned, insights, and outcomes with the broader industry.

9. Swift Electrification of Transit (SET)

Investment Plan Period 1st Quinquennial Plan (2021 – 2025)	**Assignment to Value Chain** Distribution

Objective & Scope

Swift Electrification of Transit (SET) is an EPIC 4 funded project that will evaluate promising technologies that integrate the research topics of energy buffering, islanding, and reconfigurability to help address three primary customer concerns related to transportation electrification infrastructure projects.

The project will help inform standardization of bridging solutions throughout SCE which can be used to accelerate electrification of public transportation in and outside of Disadvantaged and Vulnerable Communities (DVCs). The same solution can be deployed to interconnect with other customers that would otherwise be told to wait up to a few years for circuit upgrades.

Key Objectives include:

- Expedite deployment of charging infrastructure by leveraging energy storage, clean generation, dynamic charge management and grid constraints management to maximize the throughput of existing circuits.
- Minimize land acquisition needed for site upgrades through optimizing sizing of service points based on real-world loads, dynamic grid constraints and energy storage capabilities.

Ensure resiliency of EV charging infrastructure in outage scenarios through implementation of microgrid controller.

Schedule

Q2 2024 – Q4 2027

Project History

The project began as a result of customers having issues electrifying fleets within a reasonable amount of time, often times years due to grid upgrades. A design thinking process documented both SCE as well as the customer perspectives and helped inform the project on how to address concerns such as grid outages and long wait times.

The project aims to prove technologies that can reduce emissions (clean mobile generators), provide resiliency (microgrid), and help expedite electrification through standardized systems. Some limitations within this project will come down to the reliability of some technologies such as the Non-Li-Ion Energy Storage System, which will be evaluated in the lab for field readiness.

2025 Status Update

Accomplishments & Success Stories

- **Supervisory Control System**
  The project team has evaluated four proposals for a supervisory control system that will be the standardized local controller for microgrid deployments. This controller will have reconfigurability capabilities that will allow Distributed Energy Resources (DERs) to be plug-and-play with each deployment.

- **Dynamic Load Constraint Management System Testing**
  The team continues to evaluate the integration and ability for SCE's Distributed Energy Resource Management System (DERMS) to send dynamic schedules to a UL3141 certified controller for load constraint management. The results of this testing will be a standardized process for customers to connect to the grid while utilizing a UL3141 controller.
- **Mobile Generator Evaluation**
  The project team has evaluated seven different clean mobile generator technologies based on project needs and feasibility. The team has also completed and shared with the vendors lab test plans and scopes of work for the lab evaluation phase.
- **Energy Storage System Evaluation**
  The team has evaluated five different Non-Li-Ion energy storage system vendors for the project and aims to target up to two during the lab evaluation phase.

Challenges or Setbacks

- **Solid-State Transformer Request for Proposal:**
  The team engaged with eleven potential vendors for a solid-state transformer solution and received two proposals. Both proposals were missing critical features and still in the lab phase. Many of the vendors stated that a solution is still a few years out to becoming commercially viable. The team mitigated this issue by exploring a potential DC combiner solution.
- **DC Combiner:**
  Due to the insufficient response for solid-state transformers, the team shifted to pursuing a DC combiner architecture. The team found that while a DC combiner could be procured, there were only a couple vendors that would provide a one-off solution, and no Energy Storage System vendor would support the integration. The team mitigated the risk of utilizing a one-off solution through shifting towards a traditional AC integration.

Key Findings and Lessons Learned

- **DC Integration:**
  The team has explored all options on integrating the Generators and Energy Storage System to a DC combiner and found that all Energy Storage System vendors require a connection to a Power Conversion System. These vendors do not support this integration currently because there are no commercialized solutions for Solid State Transformers or DC Combiners currently.
- **Supervisory Control System Standardization:**
  The team has included our stakeholders in the evaluation process of the four proposals to ensure future alignment in a standardized microgrid control system. This will help streamline the tech transfer process for future deployments.

Customer Benefits

- The project team is designing generation blocks based on current vendor sizes to address various deployments ranging from 500kW to 10MW. This will ensure expedited customer interconnections.

- The team is quantifying the emissions benefits of utilizing cleaner generators which helps achieve the state's clean energy and climate goals.
- The standardization of the Supervisory Control System will allow future deployments to be quickly deployed and integrated between SCE's DERMS and DERs.

Anticipated RFPs

- **Supervisory Control System:**
  Award of the Supervisory Control System RFP is targeted for mid-February 2026.

Industry Advancement

- The team plans on developing a load constraint management system customer onboarding process static & dynamic implementation guide which will be used to connect customers to UL3141 certified controllers and DERMS.
- The team has influenced the technical requirements of solid-state transformer development by providing feedback on utility expectations and use cases for the device to the vendors that responded to the RFP.
- The team has begun standardizing a supervisory controller based on technical requirements to serve microgrid, remote grid, and energy storage deployments.

10. Thermally Optimized Advanced Duct Strategy (TOADS)

Investment Plan Period	**Assignment to Value Chain**
1st Quinquennial Plan (2021 – 2025)	Distribution

Objective & Scope

The Thermally Optimized Advanced Duct Strategy (TOADS) project aims to address duct bank overheating by evaluating sensors, cooling methods, construction materials, and duct bank configurations through modeling, deployment, and real-world testing. Following initial modeling, TOADS will deploy selected solutions in newly constructed circuits for testing and validation. If successful and cost-effective solutions are identified, these methods will be incorporated into future construction standards.

By reducing overheating and increasing usable duct bank capacity without major reconstruction, TOADS enables SCE to serve more customers faster, improve reliability, and defer or avoid costly infrastructure upgrades. This approach maximizes the value of prior ratepayer investments, lowers long-term system costs, and provides a more affordable and reliable path to meeting growing load and electrification demands.

The project aims to explore the following technologies:

- Advanced thermal modeling and simulation
- Enhanced duct bank construction materials and backfill
- Optimized duct bank configurations and layouts designed
- Temperature monitoring and sensing technologies

• Exploration of cooling methods
Schedule Q4 2025 – Q3 2032
Project History TOADS intends to build upon the lessons learned and findings from SCE's work on duct banks in the EPIC 3 project Next Generation Distribution Automation III (NGDA3) - GT-18-0006, which evaluated the feasibility of using thermal modeling combined with temperature sensing to better predict duct bank and distribution cable temperatures and improve circuit loading decisions beyond conservative static ampacity limits. The project focused on assessing sensing approaches, data integration, and the potential for real-time or near-real-time insights to support operational decision-making, while also identifying technical and practical limitations associated with monitoring-based solutions. Building on these findings, TOADS intends to use temperature sensors to gather duct bank thermal data to validate its primary objective of addressing overheating in duct banks by testing and evaluating sensors, various cooling method models, construction materials, and duct bank configurations. This approach is intended to support the development and evaluation of solutions that more effectively manage thermal loads and improve overall duct bank performance.
2025 Status Update <u>Accomplishments & Success Stories</u> • The Project was publicly announced in late September 2025 and officially launched in early November of 2025 after confirming sponsors and stakeholders. • The team baselined the Project Charter in early November and commenced official project planning. The project plans to enter the Execution Phase in Q1 2026. <u>Challenges or Setbacks</u> • No current challenges or setbacks have been identified. <u>Key Findings and Lessons Learned</u> • This year, the team has identified that there is an opportunity for improved thermal regulation in alternative duct bank construction methods. Traditional designs, materials, and cooling methods fall short in managing the thermal load effectively, leading to higher constraints, potential failures, and increased maintenance costs. <u>Customer Benefits</u> • **Lower customer costs over time** by reducing the need for costly mitigation measures, emergency repairs, and repeat construction caused by overheating duct banks. Improved thermal performance lowers maintenance and operational expenses that are ultimately borne by ratepayers.

- **Increased system capacity** without major infrastructure expansion, allowing more customers to be served using existing substations and circuits. This helps defer or avoid expensive system upgrades that would otherwise increase rates.
- **Improved reliability and reduced outages**, as better thermal management lowers the risk of insulation degradation, faults, and failures. Fewer outages translate to fewer customer disruptions and lower restoration costs.
- **Faster and more affordable service connections**, since overheating duct banks are a key constraint that delays customer energization and requires expensive workarounds. Addressing this bottleneck helps customers receive service sooner and at lower cost.
- **Extended equipment life**, reducing the frequency of asset replacement and spreading capital costs over longer periods, which stabilizes rates for customers.
- **Scalable, repeatable solutions** that can be applied across future substations and projects, maximizing the long-term value of the investment and ensuring ratepayer funds deliver benefits beyond a single site.

Anticipated RFPs

- The project anticipates issuing the following RFPs:
    - Soil Thermal Resistivity Study
    - DTS Installation
    - Duct Bank Thermal Modeling
    - New Construction Materials
    - Engineering & Construction Support
    - Duct Bank Cooling Technology
- An RFP to procure services for analysis and design changes may be considered upon finalizing the project's solution approach.

Industry Advancement

- TOADS will use a structured, utility-driven process to ensure technical findings are shared responsibly and translated into durable, industry-relevant outcomes. As modeling, deployment, and validation activities generate results, lessons learned will be documented and communicated with governing agencies and aligned with applicable industry and engineering standards, including UGS CD 120 (Conduit Bank Requirements), IEEE 399, Neher–McGrath thermal modeling methods, National Electrical Safety Code (NESC – IEEE C2), and National Electrical Code (NEC – NFPA 70).
- Findings will be shared through industry forums, technical working groups, and professional conferences, and may be documented through technical papers as appropriate.
- This approach ensures TOADS contributes to broader industry knowledge while supporting consistent, standards-based adoption of improved duct bank thermal practices across the utility sector.

5. Conclusion

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

EPIC is a critical part of SCE's technology strategy, as EPIC projects demonstrate critical technologies that help move broader technology initiatives forward. SCE continued to advance ratepayer interests through its execution of the EPIC program, whether sharing lessons learned from projects or working with the Community Advisory Panel to find ways to support ESJ communities.

(1) 2012 – 2014 Investment Plan

For the period between January 1 and December 31, 2025, SCE expended a total of $0 [107] toward project costs and $0 toward administrative costs for a grand total of $0. SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC 1 program amount to $38,642,227.

SCE initiated 16 projects, cancelled one project, and completed 15 projects. Three of these projects were completed during the calendar year 2015, four projects were completed in 2016, four projects were completed in 2017, two projects were completed in 2018, one project was completed in 2019, and one project was completed in 2020.

The list of 15 completed 2012 – 2014 Investment Plan projects is shown below:

1. Integrated Grid Project Phase 1
2. Regulatory Mandates: Submetering Enablement Demonstration
3. Distribution Planning Tool
4. Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)
5. Portable End-to-End Test System
6. Voltage and VAR Control of SCE Transmission System
7. State Estimation Using Phasor Measurement Technologies
8. Wide-Area Reliability Management & Control

[107] SCE is reviewing these credits.

9. Distributed Optimized Storage (DOS) Protection & Control Demonstration
10. Outage Management and Customer Voltage Data Analytics Demonstration
11. SA-3 Phase III Demonstration
12. Next-Generation Distribution Automation, Phase 1
13. Enhanced Infrastructure Technology Evaluation
14. Dynamic Line Rating Demonstration
15. Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)

(2) <u>2015 – 2017 Investment Plan</u>

For the period between January 1 and December 31, 2025, SCE expended a total of $951,541 toward project costs and $171,044 toward administrative costs for a grand total of $1,122,584. SCE's cumulative expenses over the lifespan of its 2015 – 2017 EPIC 2 program amount to $40,559,807. SCE committed $0 toward projects and encumbered $289,761 through executed purchase orders during this period. SCE has no uncommitted EPIC 2 funding for this period.

SCE initiated 13 projects from its approved portfolio and cancelled 3 projects. Of the remaining ten projects, one project was completed in 2017, three projects were completed in 2018, two projects were completed in 2019, one project was completed in 2020, one project was completed in 2021, and one project was completed in 2022. One project remains in execution for the 2015 – 2017 Investment Plan.

SCE's 2015 – 2017, EPIC 2 program has the following project remaining in execution:

1. System Intelligence and Situational Awareness Capabilities

The list of nine (9) completed 2015 – 2017 Investment Plan projects is shown below:

1. Integration of Big Data for Advanced Automated Customer Load Management
2. Advanced Grid Capabilities Using Smart Meter Data
3. Proactive Storm Impact Analysis Demonstration
4. Next-Generation Distribution Equipment & Automation – Phase 2
5. Regulatory Mandates: Submetering Enablement Demonstration – Phase 2
6. Versatile Plug-in Auxiliary Power System
7. Dynamic Power Conditioner
8. DC Fast Charging
9. Integrated Grid Project II

(3) <u>2018 – 2020 Investment Plan</u>

For the period between January 1 and December 31, 2025, SCE expended a total of $3,094,109 toward project costs and $268,945 toward administrative costs for a grand total of $4,137,416. SCE's cumulative expenses over the lifespan of its 2018 – 2020 EPIC 3 program amount to $32,757,919. SCE committed $5,929,898 toward projects and encumbered $3,022,792 through executed purchase orders during this period. SCE has no uncommitted EPIC 3 project funds for this period.

SCE initiated 19 projects from its approved portfolio. As of this report, SCE cancelled four projects and began executing 15 projects from its approved portfolio. Of these remaining 15 projects, one project was completed in 2021, one project was completed in 2022, one project was completed in 2023, two projects were completed in 2024, and one project was completed in 2025. Nine projects remain in execution for the 2018 – 2020 Investment Plan.

SCE's 2018 – 2020 EPIC 3 program has the following nine (9) projects remaining in execution:

1. Advanced Technology for Field Safety (ATFS)
2. Beyond Lithium-ion Energy Storage Demo

3. Next Generation Distribution Automation III
4. SA-3 Phase III Field Demonstrations
5. Service and Distribution Centers of the Future
6. Smart City Demonstration
7. Storage-Based Distribution DC Link
8. Vehicle-to-Grid Integration Using On-Board Inverter
9. Wildfire Prevention & Resiliency Technology Demonstration

The list of six (6) completed 2015 – 2017 Investment Plan projects is shown below:

1. Cybersecurity for Industrial Control Systems
2. Distributed Cyber Threat Analysis Collaboration
3. Advanced Comprehensive Hazards Tool
4. Control and Protection for Microgrids and Virtual Power Plants
5. Distributed Energy Resources (DER) Dynamics Integration Demonstration
6. Distributed Plug-In Electric Vehicle Charging Resources

(4) <u>2021 – 2025 Investment Plan</u>

For the period between January 1 and December 31, 2025, SCE expended a total of $4,408,935 toward project costs and $597,649 toward administrative costs for a grand total of $5,006,584. SCE's cumulative expenses over the lifespan of its 2021 – 2025 EPIC 4 program amount to $5,108,080. SCE budgeted $ 61,573,094.43 toward projects and encumbered $2,059,507 through executed purchase orders during this period out of its total EPIC 4 project budget of $68,051,325 during 2024.

SCE launched five (5) new projects in 2025 and continued executing five (5) projects from its approved EPIC 4 portfolio.

SCE's 2021 – 2025 EPIC 4 program is currently composed of the following ten (10) projects remaining in execution:

1. A2G Operational Efficiencies
2. Communication Assisted Protection Technologies for Inverter-based Networks (CAPTIN)
3. Flexible Alternating Current System (FACS)
4. Industrial Demand Flexibility Enabling Distribution Grid Autonomous Resilience (IDF-EDGAR)
5. Local Optimization & Grid Edge Management Systems (LO-GEMS)
6. ML-Augmented Digital Simulation (MAD-S)
7. Quantum Networking
8. Swift Electrification of Transit (SET)
9. Stability Improvement with DERs (SIDER)
10. Thermally Optimized Advanced Duct Strategy (TOADS).

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

SCE has made progress in its EPIC projects, despite facing procurement delays and vendor challenges. All of SCE's EPIC projects are expected to deliver substantial benefits to customers, enhancing the resilience and sophistication of utility infrastructure.

SCE's proactive engagement with regulatory bodies and stakeholders was crucial in advancing its EPIC 4 Investment Plan Application and successfully launching the first wave of EPIC 4 Projects in 2024. The focus has been on completing the 2015 – 2017 Investment Plan and advancing the projects from the 2018 – 2020 and 2021 – 2025 Investment Plans. The comprehensive approach taken by SCE, including the close integration of EPIC projects with SCE's overall strategy, ensures that the company continues to advance EPIC and SCE objectives.

Following the approval of the EPIC 4 Investment Plan, SCE and other Utilities convened to strategize on portfolio implementation. SCE hosted workshops to explore strategic initiatives, addressing opportunities, challenges, and community needs, with a focus on engaging disadvantaged communities. Public workshops and the annual Symposium served as platforms for SCE and EPIC Administrators to discuss key topics with stakeholders and the Commission, sharing achievements and insights from the EPIC programs. Looking ahead to 2026, SCE will continue this engagement, as well as working with its EPIC Community Advisory Panel, to prepare the EPIC 5 Investment Plan.

Building from the success in advancing and completing existing projects and launching new projects that, as described above in the Project Status Reports, continue to provide benefits to ratepayers, SCE is pleased that it, together with the other IOUs, will be able to continue as EPIC Administrator for the upcoming EPIC 5 investment cycle, and SCE is actively preparing to submit its EPIC 5 Investment Plan. SCE will continue its process of proactively engaging with regulatory bodies and the community, as well as with SCE's EPIC Community Advisory Panel, in defining Strategic Initiatives and projects in support of the Commission's EPIC 5 Strategic Goals and Strategic Objectives. SCE is planning to share its EPIC 5 Investment plans with public and community-based stakeholders, in collaboration with other EPIC Administrators, and is in the process of finalizing these plans.

SCE worked regularly with the Policy Innovation + Coordination (PICG) Coordinator to update the EPIC project database,[108] and SCE will continue its open dialogue with the stakeholders through public engagement in 2025.

c) <u>Issues That May Have Major Impact on Progress in Projects</u>

In 2026, SCE is committed to the effective completion of its final project under the EPIC 2 Investment Plan. Additionally, SCE will progress with the execution of the 9 remaining projects from the EPIC 3 Investment Plan and the 10 projects launched in from the EPIC 4 Investment Plan.

In 2025, SCE faced numerous issues that had a major impact on project progress. Due to concerns about the legal interpretation of IP flowdowns under EPIC rules, SCE had difficulties working with vendors, as projects suffered from lengthy procurement negotiations, lower than expected turnout in RFPs, and even the inability to procure equipment critical to the success of EPIC projects. These issues affected other projects, including, from EPIC 3, the Wildfire Prevention & Resiliency Technology Demonstration project and ML-Augmented Digital Simulation (MAD-S) from EPIC 4. SCE is hopeful that

---

[108] https://database.epicpartnership.org/projects

these issues will be resolved following recent legal guidance. Furthermore, SCE had extended negotiations with vendors in some projects that sometimes were not able to ultimately come to an agreement. Finally, addressing cybersecurity concerns across all projects has added to project development timetables.

Moving forward, SCE will persist in vigilantly overseeing potential project postponements, including those stemming from production and supply chain disruptions as well as disputes over EPIC's IP terms and conditions.

APPENDIX A

CONTROL AND PROTECTION FOR MICROGRIDS AND VIRTUAL POWER PLANTS

FINAL PROJECT REPORT

APPENDIX B

DISTRIBUTED PLUG-IN (DPI) ELECTRIC VEHICLE (EV) CHARGING RESOURCES

FINAL PROJECT REPORT