BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

In the Matter of the Application of Pacific Gas and Electric Company for Approval of its 2018-2020 Electric Program Investment Charge Investment Plan. (U39E).	Application 17-04-028
And Related Matters.	Application 17-05-003 Application 17-05-005 Application 17-05-009

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

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Dated: **February 28, 2020**

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In Ordering Paragraph 16 of Decision 12-05-037, the California Public Utilities Commission (Commission) ordered Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and the California Energy Commission (CEC), collectively known as Electric Program Investment Charge (EPIC) Administrators, to file annual reports concerning the status of their respective EPIC programs. A copy of the annual report is also to be served on: (1) all parties in the most recent EPIC proceedings; (2) the service lists for the most recent general rate cases of PG&E, SCE and SDG&E; and (3) each successful and unsuccessful applicant for an EPIC funding award during the previous calendar year.

Subsequently, in D.13-11-025, Ordering Paragraph 22, the Commission required the EPIC Administrators to follow the outline contained in Attachment 5 to that Decision, when preparing the EPIC annual reports. In Ordering Paragraph 23 of the same Decision, the Commission required the EPIC Administrators to provide the project information contained in Attachment 6 of the Decision as an electronic spreadsheet.

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

In compliance with the Ordering Paragraphs of D.12-05-037, D.13-11-025 and D.15-04-020, SCE respectfully submits its annual report concerning the status of its EPIC activities for 2019. This is SCE's sixth annual report pertaining to its 2012-2014 EPIC Triennial Investment Plan (Application (A.) 12-11-004), after receiving Commission approval on November 14, 2013. Furthermore, this is SCE's fourth annual report pertaining to its 2015-2017 EPIC Triennial Investment Plan (Application (A.) 14-05-005), after receiving Commission approval on April 9, 2015. Lastly, this is SCE's second annual report pertaining to its 2018-2020 EPIC Triennial Investment Plan (Application (A.) 17-05-005), after receiving Commission approval on October 25, 2018. SCE appreciates the opportunity to report to the Commission and to interested parties regarding its EPIC efforts and activities.

Respectfully submitted,

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/s/ Kris G. Vyas

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February 28, 2020

SOUTHERN CALIFORNIA EDISON COMPANY'S
2020 EPIC ANNUAL REPORT

EPIC Annual Report

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1. Executive Summary

a) Overview of Programs/Plan Highlights

2019 represented SCE's sixth full year of implementing program operations of its 2012 – 2014 Investment Plan Application[1] (EPIC I) after receiving Commission approval on November 19, 2013.[2] Furthermore, Year 2019 represented almost five full years of implementing program operations of SCE's 2015 – 2017 Investment Plan Application[3] (EPIC II) after receiving Commission approval on April 9, 2015.[4] Lastly, Year 2019 represented SCE's first full year of implementing program operations of SCE's 2018 – 2020 Investment Plan Application[5] after receiving approval on October 25, 2018.

In this report, SCE separately presents the key aspects that have followed from its 2012 – 2014 Investment Plan, 2015 – 2017 and 2018 – 2020 Investment Plans.

(1) 2012-2014 Investment Plan

For the period between January 1 and December 31, 2019, SCE expended a total of $799,100 toward project costs and $352,410 toward administrative costs for a grand total of $1,151,510. SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC program amount to $35,967,816. SCE committed $662,728 toward projects and encumbered $1,026,454 through executed purchase orders during this period. SCE has no uncommitted EPIC funding for this period.

(2) SCE Executed 16 Projects from its Approved Portfolio.

Three projects were completed during calendar year 2015, 4 projects were completed in 2016, 4 projects were completed in 2017, 2 projects were completed in 2018 and 1 project was completed in 2019. A list of completed projects is included in the 2018 – 2020 Triennial Investment Plan Projects of this Report (section 4).

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1 (A.)12-11-001.
2 D.13-11-025, OP8.
3 (A.) 14-05-005.
4 D.15-04-020, OP1.
5 A.17-05-005.

In accordance with the Commission's directives,[6] SCE has completed final project reports for all projects and included them with the Annual Report according to the years completed. The final project reports for efforts completed in 2019 are included in the Appendix of this Annual Report. Two demonstrations from the 2012-2014 Investment Plan remain in execution.

(3) <u>2015-2017 Investment Plan</u>

For the period between January 1 and December 31, 2019, SCE expended a total of $4,728,954 toward project costs and $14,778 toward administrative costs for a grand total of $4,743,732. SCE's cumulative expenses over the lifespan of its 2015 – 2017 EPIC program amount to $28,612,985. SCE committed $5,558,516 toward projects and encumbered $3,332,699 through executed purchase orders during this period. SCE has no uncommitted EPIC funding for this period.

SCE executed 13 projects from its approved portfolio. As of this report, 3 projects have been cancelled, for the reasons outlined in their respective project update sections below. Project execution activities continued on the remaining 10 projects. Of those 10 projects, 1 project was completed in 2017, 3 projects were completed in 2018 and 2 projects were completed in 2019. The final project reports for efforts completed in 2019 are included in the Appendix of this Annual Report. Four demonstrations from the 2015-2017 Investment Plan remain in execution.

(4) <u>2018-2020 Investment Plan</u>

For the period between January 1 and December 31, 2019, SCE expended a total of $942,833 toward project costs and $484,729 toward administrative costs for a grand total of $1,427,562. Since year 2019 was the first year of implementing SCE's 2018 – 2020 Portfolio, the 2019 total also represents the cumulative expenses over the lifespan of the

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

Portfolio. SCE committed $12,330,423 toward projects and encumbered $0 through during this period. SCE has $27,557,539 uncommitted EPIC project funding for this period.

SCE proposed two replacement projects: Wildfire Prevention & Resiliency Technologies Demonstration and Beyond Lithium-Ion Energy Storage Demonstration in the Joint Utilities Research Administration Plan (RAP) Application.[7] SCE's first wave of 2018 – 2020 EPIC III is composed of 15 projects; 8 projects are in the planning stage, and the following 7 projects have been launched for execution:

- Storage-Based Distribution DC Link
- Distributed Cyber Threat Analysis Collaboration
- Advanced Comprehensive Hazards Tool
- Distributed Energy Resources Dynamics Integration Demonstration
- Power System Voltage and Var Control Under High Renewables Penetration
- Cybersecurity for Industrial Control Systems
- Substation Automation (SA)-3, Phase III Field Demonstrations

b) <u>Status of Programs</u>

(1) <u>2012-2014 Investment Plan</u>

As of December 31, 2019, SCE has expended $38,220,257[8] on program costs. Table 1 below summarizes the current funding status of SCE's EPIC projects:

Table 1: 2012-2014 Triennial Investment Plan: 2019 Projects

1. Energy Resources Integration
• 4 Projects Funded   o 1 Project Completed in 2016[9]

[7] A.19-04-028, Appendix E.

[8] SCE's cumulative project expenses amounted to $35,967,816 based on the project spreadsheet in Appendix A. SCE's cumulative administration expenses amounted to $1,457,147. SCE's accounting system calculates in-house labor overheads separately which amounted to $740,189 for projects and $45,106 for administrative labor. As a result, SCE expended a total of $38,220,257 on program costs.

[9] Distribution Planning Tool.

○ 2 Projects Completed in 2018[10]
2. Grid Modernization and Optimization
• 5 Projects Funded ○ 1 Project Cancelled in Q2, 2014[11] ○ 1 Project Completed in 2015[12] ○ 1 Project Completed in 2016[13] ○ 1 Project Completed in 2017[14]
3. Customer Focused Products and Services
• 3 Projects Funded ○ 1 Project Completed in 2015[15] ○ 1 Project Completed in 2016[16] ○ 1 Project Completed in 2017[17]
4. Cross-Cutting/Foundational Strategies and Technologies
• 4 Projects Funded ○ 1 Project Completed in 2015[18] ○ 1 Project Completed in 2016[19] ○ 2 Projects Completed in 2017[20] ○ 1 Project Completed in 2019.[21]
Total Projects Funded: 16 Total Authorized Project Budget: $37,656,998[22] Total Project Spend: $35,967,816[23] Total Funding Committed: $662,728[24] Total Encumbered: $1,026,454[25] *Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*

[10] DOS Protection & Control Demonstration and Advanced Voltage and VAR Control of SCE Transmission.
[11] SCE cancelled the Superconducting Transformer project in 2014. Please refer to the project's status update in Section 4 for additional details.
[12] Portable End-to-End Test System.
[13] Dynamic Line Rating.
[14] Next Generation Distribution Automation, Phase 1.
[15] Outage Management & Customer Voltage Data Analytics.
[16] Submetering Enablement Demonstration.
[17] Beyond the Meter: Customer Device Communications Unification and Demonstration.
[18] Cyber-Intrusion Auto-Response and Policy Management System.
[19] Enhanced Infrastructure Technology Report.
[20] State Estimation Using Phasor Measurement Technologies and Deep Grid Coordination (otherwise known as the Integrated Grid Project).
[21] Wide Area Management and Control.
[22] D.12-05-037, as updated by D.13-11-025. Includes $2,045,000 transfer from administrative funds to project funds.
[23] For additional details regarding SCE's Committed Funds, please see the attached spreadsheet.
[24] *Ibid*.
[25] *Ibid*.

Table 2 below summarizes SCE's 2019 administrative expenses:

Table 2: 2012-2014 Triennial Investment Plan: 2019 Administration

• Program Administration	Total Authorized Budget: $1,855,002[26] Total Cumulative Cost: $1,457,147 Total 2019 Cost: $352,410

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

As of December 31, 2019, SCE has expended $31,795,422[27] on program costs. Table 3 below summarizes the current funding status of SCE's EPIC projects:

Table 3: 2015-2017 Triennial Investment Plan: 2019 Projects

1. Energy Resources Integration
• 3 Projects Funded 2 Projects canceled in 2016[28] 1 Project canceled in 2017[29]
2. Grid Modernization and Optimization
• 6 Projects Funded o 1 Project completed in 2017[30] o 1 Project completed in 2018[31] o 1 Project completed in 2019[32]
3. Customer Focused Products and Services
• 3 Projects Funded o 2 Projects completed in 2018[33] o 1 Project completed in 2019[34]

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[26] 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.

[27] SCE's cumulative project expenses amounted to $28,612,985 based on the project spreadsheet in Appendix A. SCE's cumulative administration expenses amounted to $2,723,257. SCE's accounting system calculates in-house labor overheads separately, which amounted to $359,735 for projects and $99,445 for program administration. As a result, SCE expended a total of $31,795,422 on program costs.

[28] Bulk System Restoration under High Renewables Penetration and Series Compensation for Load Flow Control.

[29] Optimized Control of Multiple Storage Systems.

[30] Advanced Grid Capabilities Using Smart Meter Data.

[31] Proactive Storm Impact Analysis Demonstration.

[32] Versatile Plug-in Auxiliary Power System.

[33] DC Fast Charging and Integration of Big Data for Advanced Automated Customer Load Management.

[34] Regulatory Mandates: Submetering Enablement Demonstration Phase 2.

4. Cross-Cutting/Foundational Strategies and Technologies
• 1 Projects Funded
Total Projects Funded: 13 Total Authorized Project Budget: $37,504,200[35] Total Project Spend: $28,612,985[36] Total Funding Committed: $5,558,516[37] Total Encumbered: $3,332,699[38] *Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*

Table 4 below summarizes SCE's 2019 administrative expenses:

Table 4: 2015-2017 Triennial Investment Plan: 2019 Administration

• Program Administration	Total Authorized Budget: $4,190,400[39] Total Cumulative Cost: $ 2,723,257 Total 2019 Cost: $14,778

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

As of December 31, 2019, SCE has expended $1,427,561 on program costs. Table 5 below summarizes the current funding status of SCE's EPIC projects:

Table 5: 2018-2020 Triennial Investment Plan: 2019 Projects

1. Energy Resources Integration
• 3 Projects Funded
2. Grid Modernization and Optimization
• 2 Projects Funded
3. Customer Focused Products and Services
• 0 Projects Funded
4. Cross-Cutting/Foundational Strategies and Technologies
• 2 Projects Funded
Total Projects Funded: 7 Total Authorized Project Budget: 40,830,795[40] Total Project Spend: $937,894[41] Total Funding Committed: $12,330,423[42]

[35] D.15-04-020, Ordering Paragraph 1 -- Appendix B, Table-5 p. 7.
[36] For additional details regarding SCE's Committed Funds, please see the attached spreadsheet.
[37] *Ibid*.
[38] *Ibid.*
[39] D.15-04-020, Ordering Paragraph 1 -- Appendix B, Table-5 p. 7.
[40] D.18-01-008, at p. 38.
[41] For additional details regarding SCE's Committed Funds, please see the attached spreadsheet.
[42] *Ibid*.

Total Encumbered: $0[43] *Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*

Table 6 below summarizes SCE's 2019 administrative expenses:

Table 6: 2018-2020 Triennial Investment Plan: 2019 Administration

• Program Administration	Total Authorized Budget: $4,562,100[44] Total Cumulative Cost: $484,729 Total 2019 Cost: $484,729

2. Introduction and Overview

a) Background on EPIC (General Description of EPIC)

The Commission established the EPIC Program to fund applied research and development, technology demonstration and deployment, and market facilitation programs to provide ratepayer benefits. Please refer to Decision (D.)12-05-037. This Decision further stipulates that the EPIC Program will continue through 2020[45] with an annual budget of $162 million,[46] adjusted for inflation.[47] Approximately 80% of the EPIC budget is administered by the CEC, and 20% is administered by the investor-owned utilities (IOUs). Additionally, 0.5% of the total EPIC budget funds Commission oversight of the Program.[48] The IOUs were also limited to only the area of Technology Demonstration and Deployment (TD&D) activities.[49] SCE was allocated 41.1% of the IOU portion of the budget and administrative activities.[50]

The Commission approved SCE's 2012-2014 Investment Plan[51] in D.13-11-025 on November 19, 2013. SCE submitted its 2015-2017 Investment Plan Application[52] on May 1, 2014 and the Commission approved the Application in D.15-04-020 on April 9, 2015. SCE

[43] *Ibid.*
[44] D.18-01-008, at p. 38.
[45] D.12-05-037, OP1.
[46] D.12-05-037, OP7.
[47] Using the Consumer Price Index.
[48] *Id*, OP5.
[49] *Id*.
[50] D.12-05-037, OP 7, as modified by D.12-07-001.
[51] A.12-11-004.
[52] A.14-05-005.

submitted its 2018-2020 Application on May 1, 2017 and the Commission approved the Application in D.18-10-052. SCE is currently executing its 2012-2014, 2015-2017 and 2018-2020 EPIC Investment Plans.

b) EPIC Program Components

The Commission limited SCE's triennial investment applications in this EPIC Program to TD&D projects, per D.12-05-037. The Commission defines TD&D projects as installing and operating pre-commercial technologies or strategies at a scale sufficiently large, and in conditions sufficiently reflective of anticipated actual operating environments, to enable appraisal of the operational and performance characteristics and the associated financial risks.[53]

In accordance with the Commission's requirement for TD&D projects, the IOUs continue to successfully utilize the joint IOU framework developed for the 2012-2014 cycle and enhanced for the 2015-2017 and 2018-2020 cycles with updated strategic initiatives to support the latest key drivers and policies. This includes the following four program categories: (1) energy resources integration, (2) grid modernization and optimization, (3) customer-focused products and services, and (4) cross-cutting/foundational strategies and technologies. SCE's 2012-2014, 2015-2017, 2018-2020 Investment Plans proposed projects for each of these four areas, focusing on the ultimate goals of promoting greater reliability, lowering costs, increasing safety, decreasing greenhouse gas emissions, and supporting low-emission vehicles and economic development for ratepayers.

c) EPIC Program Regulatory Process

The Commission approved SCE's 2012-2014 Application[54] in D.13-11-025 on November 19, 2013. SCE submitted its 2015-2017 Investment Plan Application[55] on May 1, 2014 and the Commission approved the Application in D.15-04-020 on April 9, 2015. The Commission opened a phase II of the proceeding to address projects proposed after Commission

[53] D.12-05-037, OP3.B.
[54] A.12-11-004.
[55] A.14-05-005.

approval of an Investment Plan. The Commission issued its Phase II Decision,[56] requiring the IOUs to file a Tier 3 advice letter for any new or materially re-scoped project. This advice filing would need to justify why the project should receive Commission approval, rather than simply waiting for the next investment plan funding cycle.

SCE submitted its 2018-2020 Investment Plan Application[57] on May 1, 2017 and the Commission approved the Application in D.18-10-52 on October 25, 2018. Within the Commission's decision approving the 2018-2020 Investment Plan Applications, the Commission directed the Utilities to file a joint RAP Application to address recommendations made by in the independent evaluator's report and to provide an opportunity to refresh the portfolio by allowing an opportunity to replace project proposals. The Joint Utilities filed the RAP Application[58] on April 23, 2019 and SCE proposed two replacement project proposals. In compliance with the Commission's requirements for the EPIC Program,[59] SCE submits its 2019 Annual Report to update the Commission and stakeholders on SCE's program implementation.

d) **Coordination**

The EPIC Administrators have collaborated throughout 2019 on the execution of the 2012-2014, 2015-2017, 2018-2020 Investment Plans, as well as the RAP Application. Specific examples of the IOUs coordinating with the CEC include:

- Biweekly meetings to discuss stakeholder engagement planning (e.g., Symposium), as well as coordination and collaboration opportunities for the investment plan administrators;
- The EPIC Symposium in Sacramento on February 19, 2019;
- RAP public engagements (e.g., Peer Program Webinar on March 26, 2019 and Public Workshop that SCE hosted on April 2, 2019);

[56] D.15-09-005.
[57] A.17-05-005.
[58] A.19-04-028.
[59] D.12-05-037, Ordering Paragraph (OP) 16, as amended in D.13-11-025, at OPs 53-54 and D.15-04-020 at OP 6.

- Participation in technical advisory committees, working groups and workshops (e.g., Energy Storage Research Needs in California,[60] Climate Scenarios and Analyses to Support Electricity Sector Vulnerability Assessment and Resilient Planning,[61] and Hourly Temperature Data on Cal-Adapt[62]); and
- Project coordination on the Electric Access System Enhancement (EASE) project.[63] EASE was funded ($4M) by the Department of Energy (DOE) under the Enabling Extreme Real-time Grid Integration of Solar Energy (ENERGISE) funding opportunity announcement (DE-FOA-0001495). SCE applied for and was awarded CEC match funding ($2M).

As mentioned above in the context of CEC coordination, all of the EPIC Administrators met on a near-weekly basis to discuss the items referenced above, coordinate investment plan activities, and plan and coordinate joint stakeholder workshops as well as the annual joint public symposium. Moreover, SCE had several collaborative meetings with the CEC to further coordinate the respective investments plans.

e) Transparent and Public Process/CEC Solicitation Activities

On February 19, 2019, SCE supported the annual EPIC Symposium in Sacramento, CA. SCE supported the CEC in a discussion on wildfire mitigation. The Joint Utilities also presented a discussion on the Commission's request and preliminary planning for the RAP. In addition to the Symposium, the Joint Utilities coordinated with the CEC on RAP public engagements, including a Peer Program Webinar on March 26, 2019 and Public Workshop on April 2, 2019. The Administrators also held a public workshop, hosted by SDG&E in San Diego on November 8, 2019. SCE discussed past EPIC achievements, as well as providing an overview of its EPIC III high-priority projects.

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[60] CEC Workshop held November 7, 2019 in San Diego.
[61] CEC Workshop held December 16, 2019 in Sacramento.
[62] CEC Workshop held December 18, 2019 in Sacramento.
[63] This three-year project is enhancing DER interconnection to the grid, with the ability to help provide services and foster optimization of resources by implementing an interoperable distributed control architecture.

SCE supported numerous parties applying for CEC EPIC funding in 2019. A total of 22 requests for Letters of Support (LOS) and Commitment (LOC) were received from a diverse array of parties (including private vendors, universities and national laboratories) showing interest in partnering on bids for CEC projects. These requests consisted of 14 LOSs and 8 LOCs. Of these requests, 3 LOSs and 0 LOC were approved by the CEC. For SCE, a LOS typically supports the premise of a project. In some instances, the LOS includes technical advisory support if: (a) the project is awarded to the recipient, and (b) the party and SCE reach a mutual understanding of what advisory support will be required.

A LOC is a greater commitment than a LOS, because the LOC includes early financial and/or technical support in the event 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. On the website, stakeholders can access SCE's Investment Plan Applications, request a LOS or LOC, and directly contact SCE with questions pertaining to EPIC.

3. Budget

a) Authorized Budget

(1) 2012 – 2014 Investment Plan

Table 5: 2017 Authorized EPIC Budget

2017 (Jan 1 - Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	$1.3M	$11.9M	$0.33M[64]
CEC Program	$5.3M	$47.7M	

(2) 2015 – 2017 Investment Plan

Table 6: 2017 Authorized EPIC Budget

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

2017 (Jan 1 - Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	$1.4M	$12.5M	$0.35M
CEC Program	$5.6M	$50M	

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

Table 7: 2018 Authorized EPIC Budget

2018 (Jan 1 - Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	$1.5M	$13.6M	$0.02M
CEC Program	$6.0M	$54.4M	

b) <u>Commitments/ Encumbrances</u>

(1) <u>2012 – 2014 Investment Plan</u>

As of December 31, 2019, SCE has committed $662,728 and encumbered $1,026,454 of its authorized 2012-2014 program budget.

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

As of December 31, 2019, SCE has committed $5,558,516 and encumbered $3,332,699 of its authorized 2015-2017 program budget.

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

As of December 31, 2019, SCE has committed $12,330,423 and encumbered $0 of its authorized 2018-2020 program budget.

(4) <u>CEC & CPUC Remittances</u>

For CEC remittances, SCE remitted $3,317,890[65] for program administration, and $26,886,611 for encumbered projects during calendar year 2019.

For CPUC remittances, SCE remitted $380,174 in calendar year 2019.

[65] SCE remitted the remaining amount of $1,646,552 to the CEC in January 2020.. The Utilities are remitting the total CEC administrative budget over 11 quarters.

c) Dollars Spent on In-House Activities

(1) 2012 – 2014 Investment Plan

As of December 31, 2019, SCE has spent $5,853,516[66] on in-house activities.

(2) 2015 – 2017 Investment Plan

As of December 31, 2019, SCE has spent $2,805,588[67] on in-house activities.

(3) 2018 – 2020 Investment Plan

As of December 31, 2019, SCE has spent $44,350[68] on in-house activities.

d) Fund Shifting Above 5% between Program Areas

2012 – 2014 Investment Plan

As of December 31, 2019, SCE does not have any pending fund shifting requests and/or approvals.

(1) 2015 – 2017 Investment Plan

As of December 31, 2019, SCE does not have any pending fund shifting requests and/or approvals.

(2) 2018 – 2020 Investment Plan

As of December 31, 2019, SCE does not have any pending fund shifting requests and/or approvals.

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66 SCE expended a total of $5,103,327 on in-house activities through 2019, based on the project spreadsheet found in Appendix A. SCE's accounting systems calculates in-house labor overheads separately, which amounted to $750,189. As a result, SCE expended a total of $5,853,516 on in-house costs.

67 SCE expended a total of $2,446,023 on in-house activities through 2019, based on the project spreadsheet found in Appendix A. SCE's accounting systems calculates in-house labor overheads separately, which amounted to $359,565. As a result, SCE expended a total of $2,805,588 on in-house costs.

68 SCE expended a total of $38,666 on in-house activities through 2019, based on the project spreadsheet found in Appendix A. SCE's accounting systems calculates in-house labor overheads separately, which amounted to $5,684. As a result, SCE expended a total of $44,350 on in-house costs.

e) Uncommitted/Unencumbered Funds

(1) 2012 – 2014 Investment Plan

As of December 31, 2018, SCE has $0 in uncommitted/unencumbered funds.

(2) 2015 – 2017 Investment Plan

As of December 31, 2018, SCE has $0 in uncommitted/unencumbered funds.

(3) 2018 – 2020 Investment Plan

As of December 31, 2019, SCE has $27,557,539[69] in uncommitted/unencumbered funds.

f) Joint CEC/SCE Projects

As of December 31, 2019, the only project with CEC participation is the DOE-funded EASE project described in section 2d of this Report. For this project, the CEC is providing match funding.

g) Non-Competitive Bidding of Funds

As stated in the RAP Application, SCE follows competitive procurement practices. However, there are limited instances when specialized expertise is needed to support a project and a competitive bid may not be possible or if costs for conducting the solicitation are than the requested technology or service. SCE will start reporting out the justification for all directly awarded contracts and provide a breakdown for all direct awards for EPIC III.

As of December 31, 2019, SCE awarded $0 in direct project awards. However, SCE did award $473,550 to CorePoint in administrative funds in a direct award to support the planning of the RAP Application.[70]

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[69] D.18-01-008, at p. 38.
[70] RAP Application, at C-1.

h) Match Funding

As filed in the RAP Application, SCE will start tracking match funding. SCE EPIC projects have not received match funding in 2019.

i) High-Level Summary

SCE provides a summary of project funding for SCE's 2012-2014, 2015-2017, and 2018-2020 Investment Plans, please refer to Table 1, Table 3, and Table 5 in Section 1b.

j) Project Status Report

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

k) Description of Projects:

i. Investment Plan Period
ii. Assignment to Value Chain
iii. Objective
iv. Scope
v. Deliverables
vi. Metrics
vii. Schedule
viii. EPIC Funds Encumbered
ix. EPIC Funds Spent
x. Partners (if applicable)
xi. Match Funding (if applicable)
xii. Match Funding Split (if applicable)
xiii. Funding Mechanism (if applicable)
xiv. Treatment of Intellectual Property (if applicable)

l) **Status Update**

The following project descriptions for the objective and scope reflect the proposals filed in the EPIC Investment Plans,[71] while the projects' status information show progress as of December 31, 2019.

[71] The EPIC I Investment Plan Application (A.)12-11-004 was filed on November 1, 2012. The EPIC II Investment Plan A.14-05-005 was filed on May 1, 2014. The EPIC III Investment Plan A.17-05-005 on May 1, 2017.

(1) 2012 – 2014 Triennial Investment Plan Projects

1. Integrated Grid Project – Phase 1

<table>
<tr><td>Investment Plan Period:
1st Triennial Plan (2012-2014)</td><td>Assignment to value Chain:
Grid Operation/Market Design</td></tr>
<tr><td colspan="2">Objective & Scope:
The project will demonstrate, evaluate, analyze and propose options that address the impacts of high distributed energy resources (DER) penetration and increased adoption of distributed generation (DG) owned by consumers directly connected to SCE’s distribution grid and on the customer side of the meter. This demonstration project is, in effect, the next step following the ISGD project. Therefore, this project focuses on the effects of introducing emerging and innovative technology into the utility and consumer end of the grid to account for this increase in DER resources. This scenario introduces the need for the utility (SCE) to assess technologies and controls necessary to stabilize the grid with increased DG adoption, and more importantly, consider possible economic models that would help SCE adapt to the changing regulatory policy and GRC structures.

This value-oriented demonstration informs many key questions that have been asked:
• What is the value of distributed generation and where is it most valuable?
• What is the cost of intermittent resources?
• What is the value of storage and where is it most valuable?
• How are DER resources/devices co-optimized?
• What infrastructure is required to enable an optimized solution?
• What incentives/rate structure will enable an optimized solution?</td></tr>
<tr><td colspan="2">Deliverables:
• An IGP cost/benefit analysis and business case
• A systems requirement specification
• An IGP demonstration architecture
• A distributed grid control architecture capable of supporting the use of market mechanism, price signals, direct control or distributed control to optimize reliability and economic factors on the distribution grid
• A data management and integration architecture supporting the overarching IGP architecture
• A supporting network and cybersecurity architecture for the IGP architecture
• Incentive structures that encourage technology adoption that provide benefits to overall system operations
• A volt/Var optimization strategy
• RFPs to secure control vendor solutions for the field demonstration phase of the IGP project
• IGP lab demonstration using a simulated environment
• Final project report (Phase 1)</td></tr>
<tr><td colspan="2">Metrics:
1a. Number and total nameplate capacity of distributed generation facilities
1b. Total electricity deliveries from grid-connected distributed generation facilities</td></tr>
</table>

1c. Avoided procurement and generation costs 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g., Auto DR) 1h. Customer bill savings (dollars saved) 1i. Nameplate capacity (MW) of grid-connected energy storage 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5a. Outage number, frequency and duration reductions 5b. Electric system power flow congestion reduction 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360) 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360) 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360) 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 7j. Provide consumers with timely information and control options (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer

9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs
9c. EPIC project results referenced in regulatory proceedings and policy reports
9d. Successful project outcomes ready for use in California IOU grid (Path to market)

Schedule:
IGP Phase 1: Q2 2014 – Q4 2017

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$0	$17,425,533

Partners:
None

Match Funding:	**Match Funding split:**	**Funding Mechanism:**
N/A	N/A	N/A

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

Status Update
The final project report is complete, was submitted with the 2017 Annual Report, and is available on SCE's public EPIC website.

2. Regulatory Mandates: Submetering Enablement Demonstration

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

Objective & Scope:
On November 14, 2013, the Commission voted to approve the revised Proposed Decision (PD) Modifying the Requirements for the Development of a Plug-In Electric Vehicle Submetering Protocol set forth in D.11-07-029. The investor-owned utilities (IOUs) are to implement a two phased pilot beginning in May 2014, with funding for both phases provided by the EPIC. This project, Phase I of the pilot, will: (1) evaluate the demand for Single Customer of Record submetering, (2) estimate billing integration costs, (3) estimate communication costs, and (4) evaluate customer experience. IOUs and external stakeholders will finalize the temporary metering requirements, develop a template format used to report submetered, time-variant energy data, register Submeter Meter Data Management Agents and develop a Customer Enrollment Form, and finalize MDMA Performance Requirements. The IOUs will also solicit a third-party evaluator to evaluate the customer experience.

Deliverables:
1. Submetering Protocol Report
2. Manual Subtractive Billing Procedure
3. 3PE Final Report and Recommendation

Metrics:
6a. TOTAL number of SCE customer participants (Phase 1 & 2 each have 500 submeter limit)
6b. Number of SCE NEM customer participants (Phase 1 & 2 each have 100 submeter limit of 500 total)

6c. Submeter MDMA on-time delivery of customer submeter interval usage data 6d. Submeter MDMA accuracy of customer submeter interval usage data
Schedule: Q1 2014 – Q1 2017

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,134,600

Partners: N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site.

3. Distribution Planning Tool

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

Objective & Scope: This project involves the creation, validation, and functional demonstration of an SCE distribution system model that will address the future system architecture that accommodates distributed generation (primarily solar photovoltaic), plug-in electric vehicles, energy storage, customer programs (demand response, energy efficiency), etc. The modeling software to be used allows for implementation of advanced controls (smart charging, advanced inverters, etc.). These controls will enable interaction of a residential energy module and a power flow module. It also enables the evaluation of various technologies from an end-use customer perspective as well as a utility perspective, allowing full evaluation from substation bank to customer. This capability does not exist today. The completed model will help SCE demonstrate, communicate and better respond to technical, customer and market challenges as the distribution system architecture evolves.
Deliverables: • Grid LAB-D user interface • SCE circuit model • Updated GridLAB-D to handle Cyme 7 database • Base cases & benchmark • Specifications for test cases from stakeholders • Created test cases • Periodic updates/meetings with stakeholders • Executed test cases • Final project report
Metrics: 1d. Number and percentage of customers on time variant or dynamic pricing tariffs

1g. Percentage of demand response enabled by automated demand response technology (e.g., Auto DR) 5c. Forecast accuracy improvement 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360) 8c. Number of times reports are cited in scientific journals and trade publications for selected projects 8d. Number of information sharing forums held 8f. Technology transfer 9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market)		
Schedule: Q1 2014 – Q1 2017		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,071,118	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		

Status Update
The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site.

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

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

7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360) 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360) 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360) 7g. Integration of cost-effective smart appliances and consumer devices (PU Code § 8360) 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 7j. Provide consumers with timely information and control options (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9a. Description/documentation of projects that progress deployment, such as Commission approval of utility proposals for widespread deployment or technologies included in adopted building standards 9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market)		
Schedule: Q3 2014 – Q4 2017		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,478,149	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update The EPIC I Final Report for the Beyond the Meter Project is complete, is being submitted with the 2017 Annual Report, and will be posted on SCE's public EPIC web site.		

5. Portable End-to-End Test System

<table>
<tr><td colspan="2">Investment Plan Period:
1st Triennial Plan (2012-2014)</td><td colspan="2">Assignment to value Chain:
Transmission</td></tr>
<tr><td colspan="4">Objective & Scope:
End-to-end transmission circuit relay testing has become essential for operations and safety. SCE technicians currently test relay protection equipment during commissioning and routing testing. Existing tools provide a limited number of scenarios (disturbances) for testing, and focus on testing protection elements; not testing system protection. This project will demonstrate a robust portable end-to-end toolset (PETS) that addresses: 1) relay protection equipment, 2) communications, and 3) provides a pass/fail grade based on the results of automated testing using numerous simulated disturbances. PETS will employ portable Real-Time Digital Simulators (RTDS’s) in substations at each end of the transmission line being tested. Tests will be documented using a reporting procedure used in the Power Systems Lab today; this will help ensure that all test data is properly evaluated.</td></tr>
<tr><td colspan="4">Deliverables:
PETS portable RTDS test equipment
PETS operating instructions
PETS standard test report
Final project report</td></tr>
<tr><td colspan="4">Metrics:
3a. Maintain / reduce operations and maintenance costs
5a. Outage number, frequency and duration reductions
6a. Reduce testing cost
6b. Number of terminals tested on a line (more than 2 terminals/substations)
7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
8b. Number of reports and fact sheets published online
8d. Number of information sharing forums held
8f. Technology transfer
9c. EPIC project results referenced in regulatory proceedings and policy reports
9e. Technologies available for sale in the marketplace (when known)</td></tr>
<tr><td colspan="4">Schedule:
Q1 2014 – Q4 2015</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$0</td><td colspan="2">EPIC Funds Spent:
$39,563</td></tr>
<tr><td colspan="4">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td colspan="2">Match Funding split:
N/A</td><td>Funding Mechanism:
N/A</td></tr>
<tr><td colspan="4">Treatment of Intellectual Property
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="4">Status Update</td></tr>
</table>

The final project report is complete, was submitted with the 2015 Annual Report, and is available on SCE's public EPIC web site.

6. Voltage and VAR Control of SCE Transmission System

<table>
<tr><td>Investment Plan Period:
1st Triennial Plan (2012-2014)</td><td>Assignment to value Chain:
Transmission</td></tr>
<tr><td colspan="2">Objective & Scope:
This project involves demonstrating software and hardware products that will enable automated substation volt/var control. Southern California Edison (SCE) will demonstrate a Substation Level Voltage Control (SLVC) unit working with a transmission control center Supervisory Central Voltage Coordinator (SCVC) unit to monitor and control substation voltage. The scope of this project includes systems engineering, testing, and demonstration of the hardware and software that could be operationally employed to manage substation voltage.</td></tr>
<tr><td colspan="2">Deliverables:
Demonstration design specification
Construction documents: drawings, cable schedule, and bill of material
Monitoring console software and hardware
Advanced Volt/VAR Control (AVVC) testing
Field deployment
Controller operation monitoring and adjustment
AVVC final report and closeout</td></tr>
<tr><td colspan="2">Metrics:
3a. Maintain / reduce operations and maintenance costs
3c. Reduction in electrical losses in the transmission and distribution system
3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear
7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)
8b. Number of reports and fact sheets published online
8d. Number of information sharing forums held
8f. Technology transfer
9c. EPIC project results referenced in regulatory proceedings and policy reports
9d. Successful project outcomes ready for use in California IOU grid (Path to market)</td></tr>
<tr><td colspan="2">Schedule:
Q1 2014 – Q4 2018</td></tr>
<tr><td>EPIC Funds Encumbered:
$0</td><td>EPIC Funds Spent:
$853,165</td></tr>
<tr><td colspan="2">Partners:
N/A</td></tr>
</table>

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update The Final Report for the Voltage and VAR Control of SCE Transmission System is complete, was submitted with the 2018 Annual Report, and is posted on SCE's public EPIC web site.		

7. Superconducting Transformer (SCX) Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Distribution	
Objective & Scope: This project was cancelled in 2014. No further work is planned. *Original Project Objective and Scope:* SCE will support this $21M American Reinvestment and Recovery Act (ARRA) Superconducting Transformer (SCX) project by providing technical expertise and installing and operating the transformer at SCE's MacArthur substation. The SCX prime contractor is SuperPower Inc. (SPI), teamed with SPX Transformer Solutions (SPX) {formerly Waukesha Electric Systems}. SCE has provided two letters of commitment for SCX. The SCX project will develop a 28 MVA High Temperature Superconducting, Fault Current Limiting (HTS-FCL) transformer. The transformer is expected to be installed in 2015. SCE is supporting this project and is not an ARRA grant sub-recipient. SCE is being reimbursed for its effort by EPIC. SCE's participation in this project was previously approved under the now-defunct California Energy Commission's PIER program.		
Deliverables: N/A		
Metrics: N/A		
Schedule: Project was cancelled in Q2 2014.		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $10,241	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed.		

Status Update
SCE formally cancelled this project in Q3 2014.

8. State Estimation Using Phasor Measurement Technologies

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Grid Operation/Market Design	
Objective & Scope: Accurate and timely power system state estimation data is essential for understanding system health and provides the basis for corrective action that could avoid failures and outages. This project will demonstrate the utility of improved static system state estimation using Phasor Measurement Unit (PMU) data in concert with existing systems. Enhancements to static state estimation will be investigated using two approaches: 1) by using GPS time to synchronize PMU data with Supervisory Control and Data Acquisition (SCADA) system data; 2) by augmenting SCE's existing conventional state estimator with a PMU based Linear State Estimator (LSE).		
Deliverables: • Demonstrated algorithm performance based on observations. • Report that addresses tests conducted and test results. • Final project report.		
Metrics: 6a. Enhanced grid monitoring and on-line analysis for resiliency 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the marketplace (when known)		
Schedule: Q2 2014 – Q4 2017		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $822,179	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update The final project report is complete, was submitted with the 2017 Annual Report, and is available on SCE's public EPIC web site.		

9. Wide-Area Reliability Management & Control

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Grid Operation/Market Design
Objective & Scope: With the planned wind and solar portfolio of 33% penetration, a review of the integration strategy implemented in the SCE bulk system is needed. The basic premise for the integration strategy is that a failure in one area of the grid should not result in failures elsewhere. The approach is to minimize failures with well designed, maintained, operated and coordinated power grids. New technologies can provide coordinated wide-area monitoring, protection, and control systems with pattern recognition and advance warning capabilities. This project will demonstrate new technologies to manage transmission system control devices to prevent cascading outages and maintain system integrity.	
Deliverables: • Lab demonstration of control algorithms using real time simulations with Hardware in the loop • Develop recommendations based on the control system testing • Final project report	
Metrics: 6a. Enhanced contingency planning for minimizing cascading outages 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer	

Schedule: Q2 2014 – Q3 2019		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $745,062	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update The Final Report for the Wide-Area Reliability Management & Control project is complete, is being submitted with the 2019 Annual Report, and will be posted on SCE's public EPIC web site.		

10. Distributed Optimized Storage (DOS) Protection & Control Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Distribution
Objective & Scope: The purpose of this demonstration is to provide end-to-end integration of multiple energy storage devices on a distribution circuit/feeder to provide a turn-key solution that can cost-effectively be considered for SCE's distribution system, where identified feeders can benefit from grid optimization and variable energy resources (VER) integration. To accomplish this, the project team will first identify distribution system circuits where multiple energy storage devices can be operated centrally. Once a feeder is selected, the energy storage devices will be integrated into the control system and tested to demonstrate central control and monitoring. At the end of the project, SCE will have established necessary standards-based hardware and control function requirements for grid optimization and renewables integration with distributed energy storage devices. A second part of this project will investigate how energy storage devices located on distribution circuits can be used for reliability while also being bid into the CAISO markets to provide ancillary services. This is also known as dual-use energy storage. Initial use cases will be developed to determine the requirements for the control systems necessary to accomplish these goals.	
Deliverables: • Target circuit models • Selected circuits for the project • Requirement development for solution • RFP for the control system • Procurement of the control system • Evaluation of centralized controller and representative energy storage devices	

• Test platform readiness for protection evaluation • Engagement of all expected SCE departments for deployment • Procurement of M&V equipment • Deployment of M&V equipment and centralized controller • M&V complete and final report
Metrics: 1c. Avoided procurement and generation costs 1i. Nameplate capacity (MW) of grid-connected energy storage 3b. Maintain / Reduce capital costs 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 6a. Benefits in energy storage sizing through device operation optimization 6b. Benefits in distributed energy storage deployment vs. centralized energy storage deployment 7a. Description of the issues, project(s), and the results or outcomes 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports.
Schedule: Q2 2014 – Q4 2017

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $74,436	
Partners: None		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update The Final Report for the Voltage and VAR Control of SCE Transmission System is complete, was submitted with the 2018 Annual Report, and is posted on SCE's public EPIC web site.		

11. Outage Management and Customer Voltage Data Analytics Demonstration

Investment Plan Period:	Assignment to value Chain:
1st Triennial Plan (2012-2014)	Grid Operation/Market Design

Objective & Scope:
Voltage data and customer energy usage data from the Smart Meter network can be collected and leveraged for a range of initiatives focused on achieving operational benefits for Transmission & Distribution. Before a full implementation of this new approach can be considered, a demonstration project will be conducted to understand how voltage and consumption data can be best collected, stored, and integrated with T&D applications to provide analytics and visualization capabilities. Further, Smart Meter outage and restoration event (time stamp) data can be leveraged to improve customer outage duration and frequency calculations. Various stakeholders in T&D have identified business needs to pursue more effective and efficient ways of calculating SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index), and MAIFI (Momentary Average Interruption Frequency Index) for internal and external reporting.

Before a full implementation of this new approach can be considered, a demonstration project will be conducted to understand the feasibility and value of providing smart meter data inputs and enhanced methodology for calculating the Indexes. The demonstration will focus on a limited geography (SCE District or Region) to obtain the Smart Meter inputs to calculate the Indexes and compare that number with the current methodologies to identify any anomalies. A hybrid approach using the Smart Meter-based input data, combined with a better comprehensive electric connectivity model obtained from GIS, may provide a more efficient and effective way of calculating the Indexes. Additionally, we will carry out an effort to evaluate the accuracy of the Transformer Load Mapping data.

Deliverables:
- Voltage Analytics for Power Quality Model
- Simulated Circuit Condition Model
- Customer and Transformer Load Analysis Model
- Enhanced Inputs and SAIDI/SAIFI Analysis
- Final Project Report

Metrics:
3a. Maintain / reduce operations and maintenance costs
5c. Forecast accuracy improvement
5f. Reduced flicker and other power quality differences
6a. Enhance Outage Reporting Accuracy and SAIDI/SAIFI Calculation
8b. Number of reports and fact sheets published online
8f. Technology transfer
9c. EPIC project results referenced in regulatory proceedings and policy reports

Schedule:
Q1 2014 – Q4 2015

EPIC Funds Encumbered:	EPIC Funds Spent:
$0	$1,018,697

Partners:
N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update The final project report is complete, was submitted with the 2015 Annual Report, and is available on SCE's public EPIC web site.		

12. SA-3 Phase III Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Transmission
Objective & Scope: This project is intended to apply the findings from the Substation Automation Three (SA-3) Phase II (Irvine Smart Grid Demonstration) project to demonstrate real solutions to automation problems faced by SCE today. The project will demonstrate two standards-based automation solutions (sub-projects) as follows. Subproject 1 (Bulk Electric System) will address issues unique to transmission substations including the integration of centrally managed critical cyber security (CCS) systems and NERC CIP compliance. When the project was proposed, Subproject 2 (Hybrid) intended to address the integration of SA-3 capabilities with SAS and SA-2 legacy systems. In 2016, SA-3 Hybrid scope was completely dropped from the EPIC SA-3 phase III Demonstration. Furthermore, as part of the systems engineering, the SA-3 technical team will demonstrate two automation tools as follows: Subproject 3 (Intelligent Alarming) will allow substation operators to pinpoint root cause issues by analyzing the various scenarios, and implement an intelligent alarming system that can identify the source of the problem and give operators only the relevant information needed to make informed decisions; and Subproject 4 (Real Time Digital Simulator (RTDS) Mobile Testing) will explore the benefits of automated testing using a mobile RTDS unit, and propose test methodologies that can be implemented into the factory acceptance testing (FAT) and site acceptance testing (SAT) testing process.	
Deliverables: • Bulk & Hybrid System Design Drawings & Diagrams • Hybrid System Deployment and Demonstration • BES System Deployment and Demonstration • Final Project Report	
Metrics: 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 5a. Outage number, frequency and duration reductions 5i. Increase in the number of nodes in the power system at monitoring points 6a. Increased cybersecurity 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)	

<table>
<tr><td colspan="3">7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)
7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
8b. Number of reports and fact sheets published online
8d. Number of information sharing forums held
8f. Technology transfer
9c. EPIC project results referenced in regulatory proceedings and policy reports
9d. Successful project outcomes ready for use in California IOU grid (Path to market)
9e. Technologies available for sale in the marketplace (when known)</td></tr>
<tr><td colspan="3">Schedule:
Q1 2014 – Q3 2021</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$1,026,454</td><td>EPIC Funds Spent:
$4,917,620</td></tr>
<tr><td colspan="3">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td>Match Funding split:
N/A</td><td>Funding Mechanism:
N/A</td></tr>
<tr><td colspan="3">Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="3">Status Update:
2019 accomplishments:
In 2019 the SA-3 Phase 3 Project focused primarily on defining and integrating cybersecurity and compliance requirements for the project. Significant efforts were made to perform cybersecurity assessments and define cybersecurity requirements and solutions for the Substation Management System (SMS), the Protection Automation Controller Annunciator, Substation Network, and connectivity to the historian from the Human Machine Interface. A significant focus was placed on the SMS cybersecurity requirements pertaining to device password management, authorization, authentication, and encryption. Close collaboration occurred with the vendor to implement configuration changes. Testing of this cybersecurity requirement is expected to commence in Q1 2020.

As the cybersecurity and compliance efforts were underway the team began functional testing of the SMS system, and worked closely with the manufacturer to resolve the issues encountered, as well as documenting functional gaps. The team defined the IEC 61850 configuration file options to be utilized between the HMI and the Data historian and began initial testing. Complete HMI to Data Historian testing is expected to be completed in 2020.</td></tr>
</table>

13. Next-Generation Distribution Automation

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

Objective & Scope:

SCE's current distribution automation scheme often relies on human intervention that can take several minutes (or longer during storm conditions) to isolate faults, is only capable of automatically restoring power to half of the customers on the affected circuit, and needs to be replaced due to assets nearing the end of their lifecycle. In addition, the self-healing circuit being demonstrated as part of the Irvine Smart Grid Demonstration is unique to the two participating circuits and may not be easily applied elsewhere. As a result, the Next-Generation Distribution Automation project intends to demonstrate a cost-effective advanced automation solution that can be applied to the majority of SCE's distribution circuits.

This solution will utilize automated switching devices combined with the latest protection and wireless communication technologies to enable detection and isolation of faults before the substation circuit breaker is opened, so that at least 2/3 of the circuit load can be restored quickly. This will improve reliability and reduce customer minutes of interruption. The system will also have directional power flow sensing to help SCE better manage distributed energy resources on the distribution system. At the end of the project, SCE will provide reports on the field demonstrations and recommend next steps for new standards for next-generation distribution automation.

Deliverables:

- Remote Intelligent Switch demonstration and report
- Overhead and Underground Remote Fault Indicators demonstration and report
- Intelligent Fuses demonstration and report
- Power Electronic Transformer demonstration and report
- Secondary Network Monitoring demonstration and report
- Final Project Report

Metrics:

3a. Maintain / Reduce operations and maintenance costs
3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear
5a. Outage number, frequency and duration reductions
5c. Forecast accuracy improvement
5d. Public safety improvement and hazard exposure reduction
5e. Utility worker safety improvement and hazard exposure reduction
5i. Increase in the number of nodes in the power system at monitoring points
6a. Improve data accuracy for distribution substation planning process
7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)

7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the marketplace (when known)		
Schedule: Q1 2014 – Q4 2017		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $4,020,410	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: The final project reports were completed and submitted with the 2017 Annual Report, and are available on SCE's public EPIC web site. SCE has completed an Executive Summary Report that ties the subprojects together, which was submitted with the 2018 Annual Report, and is posted on SCE's public EPIC web site.		

14. Enhanced Infrastructure Technology Evaluation

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Distribution
Objective & Scope: At the request of Distribution Apparatus Engineering (DAE) group's lead Civil Engineer, Advanced Technology (AT) will investigate, demonstrate, and evaluate recommendations for enhanced infrastructure technologies. The project will focus on evaluating advanced distribution sectional poles (hybrid, coatings, etc.), concealed communications on assets, vault monitoring systems (temperature, water, etc.), and vault ventilation systems. Funding is needed to investigate the problem, engineering, demonstrate alternatives, and come up with recommendations. SCE sees the need for poles that can withstand fires and have a better lifecycle cost, and provide installation efficiencies when compared to existing wood pole replacements. Due to increased city restrictions, there is a need for more concealed communications on our assets such as streetlights (e.g., on the ISGD project, the City of Irvine would not permit SCE to install repeaters on streetlights due to aesthetics). DAE also sees the need for technologies that may minimize premature vault change-outs (avg. replacement cost is ~$250K). At present, DAE does not have the necessary real-time vault	

data to sufficiently address the increasing vault deterioration issue nor do we utilize a hardened ventilation system that would help this issue by removing the excess heat out of the vaults (blowers last ~ 2 years, need better bearings for blower motors, etc.).

Deliverables:
- Vault Monitoring Technologies Demonstration Report
- Vault Ventilation Field Demonstration Report
- Hybrid Pole Demonstration Report
- Concealed Communication Assets Demonstration Report
- Final Project Report

Metrics:
3a. Maintain / Reduce operations and maintenance costs
3b. Maintain / Reduce capital costs
4g. Wildlife fatality reductions (electrocutions, collisions)
5a. Outage number, frequency and duration reductions
6a. Operating performance of underground vault monitoring equipment
8b. Number of reports and fact sheets published online
8d. Number of information sharing forums held
8f. Technology transfer
9c. EPIC project results referenced in regulatory proceedings and policy reports

Schedule:
Q2 2014 – Q4 2016

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$0	$79,119

Partners:
N/A

Match Funding:	**Match Funding split:**	**Funding Mechanism:**
N/A	N/A	N/A

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

Status Update:
The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site.

15. Dynamic Line Rating Demonstration

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

Objective & Scope:
Transmission line owners apply fixed thermal rating limits for power transmission lines. These limits are based on conservative assumptions of wind speed, ambient temperature and solar radiation. They are established to help ensure compliance with safety codes, maintain the integrity of line materials, and help secure network reliability. Monitored transmission lines can be more fully utilized to improve network efficiency. Line tension is directly related to average conductor temperature. The tension of a power line is directly related to the current rating of the line. This project will demonstrate the CAT-1 dynamic line rating solution. The CAT-1 system will monitor the tension of transmission lines in real-time to calculate a dynamic daily rating. If successful, this solution will allow SCE to perform real-

time calculations in order to determine dynamic daily rating of transmission lines, thus increasing transmission line capacity.		
Deliverables: • Installed Dynamic Line Rating System Prototypes • Final Project Report		
Metrics: 3b. Maintain / Reduce capital costs 5b. Electric system power flow congestion reduction 6a. Increased power flow throughput 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the marketplace (when known)		
Schedule: Q2 2014 – Q1 2016		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $468,601	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site.		

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

<table>
<tr><td colspan="2">Investment Plan Period:
1st Triennial Plan (2012-2014)</td><td colspan="2">Assignment to value Chain:
Grid Operation/Market Design</td></tr>
<tr><td colspan="4">Objective & Scope:
Viasat in partnership with SCE and Duke Energy has been awarded a DOE contract (DE-0E0000675) to deploy a Cyber-intrusion Auto-response and Policy Management System (CAPMS) to provide real-time analysis of root cause, extent and consequence of an ongoing cyber intrusion using proactive security measures. CAPMS will be demonstrated in the SCE Advanced Technology labs at Westminster, CA. The DOE contract value is $6M with SCE & Duke Energy offering a cost share of $1.6M and $1.2M respectively.</td></tr>
<tr><td colspan="4">Deliverables:
System Requirements Artifact
Measurement and Validation Data
System Test Results
Final Project Report</td></tr>
<tr><td colspan="4">Metrics:
5a. Outage number, frequency and duration reductions
7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)
8b. Number of reports and fact sheets published online
8d. Number of information sharing forums held
8f. Technology transfer
10a. Description or documentation of funding or contributions committed by others
10c. Dollar value of funding or contributions committed by others</td></tr>
<tr><td colspan="4">Schedule:
Q3 2014 – Q3 2015</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$0</td><td colspan="2">EPIC Funds Spent:
$1,809,323</td></tr>
<tr><td colspan="4">Partners:
Viasat; Duke Energy</td></tr>
<tr><td>Match Funding:
N/A</td><td colspan="2">Match Funding split:
N/A</td><td>Funding Mechanism:
N/A</td></tr>
<tr><td colspan="4">Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="4">Status Update:
The final project report is complete, was submitted with the 2015 Annual Report, and is available on SCE's public EPIC web site.</td></tr>
</table>

(2) 2015 – 2017 Triennial Investment Plan Projects

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

<table>
<tr><td colspan="2">Investment Plan Period:
2nd Triennial Plan (2015-2017)</td><td colspan="2">Assignment to value Chain:
Demand-Side Management</td></tr>
<tr><td colspan="4">Objective & Scope:
This proposed project builds upon the “Beyond the Meter Advanced Device Communications” project from the first EPIC triennial investment plan, and proposes to demonstrate how the concept of “big data”[72] can be leveraged for automated load management. More specifically, this potential project would demonstrate the use of big data acquired from utility systems such as SCE’s advanced metering infrastructure (AMI), distribution management system (DMS), and Advanced Load Control System (ALCS) and by communicating to centralized energy hubs at the customer level to determine the optimal load management scheme.</td></tr>
<tr><td colspan="4">Deliverables:
• DERMS Functional Specification
• Acceptance Test Plan and Report
• Final Project Report</td></tr>
<tr><td colspan="4">Metrics:
7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)
7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)
7f. Deployment of cost-effective smart technologies, including real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360)
7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
8e. Stakeholders attendance at workshops
8f. Technology transfer</td></tr>
<tr><td colspan="4">Schedule:
Q1 2016-Q4 2018</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$0</td><td colspan="2">EPIC Funds Spent:
$1,199,301</td></tr>
<tr><td colspan="4">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td colspan="2">Match Funding split:</td><td>Funding Mechanism:
N/A</td></tr>
</table>

[72] Big data refers to information available as a result from energy automation and adding sensors to the grid.

	N/A	

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: The Final Report for the Integration of Big Data for Advanced Automated Customer Load Management is complete, was submitted with the 2018 Annual Report, and is posted on SCE's public EPIC web site.

2. Advanced Grid Capabilities Using Smart Meter Data

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution	
Objective & Scope: This project will examine the possibility of establishing the Phasing information for distribution circuits, by examining the voltage signature at the meter and transformer level, and by leveraging the connectivity model of the circuits. This project will also examine the possibility of establishing transformer to meter connectivity based on the voltage signature at the meter and at the transformer level.		
Deliverables: • Validated TLM algorithm • Validated Phase ID algorithm • Final project report		
Metrics: 3a. Maintain / Reduce operations and maintenance costs 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 8d. Number of information sharing forums held 8f. Technology transfer		
Schedule: Q3 2015 – Q1 2017		
EPIC Funds Encumbered: $	**EPIC Funds Spent:** $207,088	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: The final project report is complete, was submitted with the 2017 Annual Report, and is available on SCE's public EPIC web site.		

3. Proactive Storm Impact Analysis Demonstration

<table>
<tr><td colspan="2">Investment Plan Period:
2nd Triennial Plan (2015-2017)</td><td colspan="2">Assignment to value Chain:
Distribution</td></tr>
<tr><td colspan="4">Objective & Scope:
This project will demonstrate proactive storm analysis techniques prior to the storm’s arrival and estimate its potential impact on utility operations. In this project, we will investigate certain technologies that can model a developing storm and its potential movement through the utility service territory based on weather projections. This information and model will then be integrated with the Geographic Information System (GIS) electrical connectivity model, Distribution Management System (DMS), and Outage Management System (OMS) capabilities, along with historical storm data, to predict the potential impact on the service to customers. In addition, this project will demonstrate the integration of near real-time meter voltage data with the GIS network to develop a simulated circuit model that can be effectively utilized to manage storm responses and activities, and deploy field crews.</td></tr>
<tr><td colspan="4">Deliverables:
RFP Package
Requirements / Use Cases
Measurement and Validation Plan
Supplier’s Pilot Report
Technology Transfer Plan
Final project report</td></tr>
<tr><td colspan="4">Metrics:
2a. Hours worked in California and money spent in California for each project
3a. Maintain / Reduce operations and maintenance costs
3b. Maintain / Reduce capital costs
5a. Outage number, frequency and duration reductions
5c. Forecast accuracy improvement
5d. Public safety improvement and hazard exposure reduction
8f. Technology transfer
9d. Successful project outcomes ready for use in California IOU grid (Path to market)
9e. Technologies available for sale in the marketplace (when known)</td></tr>
<tr><td colspan="4">Schedule:
Q3 2015 – Q4 2018</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$0</td><td colspan="2">EPIC Funds Spent:
$1,208,125</td></tr>
<tr><td colspan="4">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td colspan="2">Match Funding split:
N/A</td><td>Funding Mechanism:
N/A</td></tr>
<tr><td colspan="4">Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="4">Status Update:</td></tr>
</table>

The Final Report for the Proactive Storm Impact Analysis Demonstration is complete, was submitted with the 2018 Annual Report, and is posted on SCE's public EPIC web site.

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

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

Deliverables: • **Hybrid Pole:** specification and report • **Underground Antenna:** functional specification, lab test report, demonstration summary and report • **Underground Remote Fault Indicator:** identification of viable products, publication of standard SCE-configured prototype Mobile Application and report • **Long Beach Network:** improved situational awareness and alarm approach, AT Laboratory SCADA network, DMS back-office recommended architecture and algorithm document, Software Requirements Document, Long Beach Distribution Network Contingency Analysis and Selection Algorithm Report, Standard, FAT & SAT Test Plan/Acceptance Criteria, FAT report, SAT report, training documents and report • **Remote Intelligence Switch:** Substation Radios, Field Radios, Support Software, Underground Interrupters, Documentation and report • **Intelligent Fuse:** delivery of single phase unit, single phase unit standard approval and publication, training of single phase unit, final report of single phase unit, delivery of three phase unit, three phase unit standard approval and publication, training of three phase unit and final report of three phase unit • **High Impedance:** Prototype 1, Prototype 2, Phase 2B Test Documentation and report	
Metrics: 3a. Maintain/reduce operations and maintenance costs 3e. Non-energy economic benefits 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communication concerning grid operations and status, and distribution automation (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)	
Schedule: Q3 2016 – Q4 2020	
EPIC Funds Encumbered: $973,091	**EPIC Funds Spent:** $5,242,224
Partners: N/A	

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		

Status Update:
2019 Accomplishments:
Remote Integrated Switch (RIS):
The RIS team supported the successful deployment of the 2.5 Extended scheme at the Johanna Substation. In addition, the team completed validation testing of the 3.5 Extended scheme concept. SCE partnered with an Augmented Reality (AR) vendor and created AR content to help overcome Organizational Change Management (OCM) challenges and provide best practices to electrical technicians. Lastly, the project team designed, negotiated and executed a new program phase to address lessons learned and stakeholder concerns related to a large deployment and system scalability.

High Impedance Fault Detection:
In 2019 the system hardware upgrade was completed. In March, SCE completed the initial testing of the upgraded hardware. The results of the testing were promising in that SCE was able to detect wired down scenarios that were unable to be detected in previous tests. A second round of testing was scheduled to validate March's results but were delayed due to unforeseen circumstances. These validation tests are projected to take place 1st quarter of 2020.

Real-time Equipment Health Diagnostic:
Completed evaluation of two vendors and one was selected to move forward in 2019 contingent on their ability to produce a Field ready prototype for demonstrations on SCE circuitry. The vendor was unable to produce a Field ready prototype so no further work was done regarding this project in 2019.

Long Beach Secondary Network Situation Awareness:
Field evaluation results indicated the Long Beach NMS tool was deficient in terms of State Estimation on the secondary side (50% to 300% error). SCE determined that unless State Estimation values are within 10% of measured values, SCE will not consider the NMS tool to be suitable for field deployment. Oracle was offered an extension to 10/15/2019 to improve its algorithm but was unable to make much progress by 10/15/2019. Oracle was then given a deadline of 12/31/2019 to deliver better results but was unable to do so. The NMS project had, therefore, been effectively canceled.

As a substitute for NMS, SCE developed an application called LENS (Long-Beach Easy Network Simulator) to provide Operations and Field Engineering with similar capabilities in terms of State Estimation and modeling. The LENS prototype was successfully demonstrated to MW Field Engineering on 1/7/2020 (~5% error) and presented to Long Beach District on 1/8/2020. MW FE and LB District indicated they believe LENS to be a viable alternative for NMS and will provide assistance in further development.

Underground Remote Fault Indicator:
SCE conducted field demonstrations of underground remote fault indicators with capabilities to be installed without an outage, submersible, integrated radio, power harvesting, bi-directional power flow detection, real-time current monitoring.
In 2019 during demonstration & monitoring phase, there were several hardware and software issues on the field installed systems due to harsh environmental submersible challenges and new firmware upgrade.

Power Delivery Products (Supplier-1):
1) SCE successfully completed the evaluation for non-submersible applications (e.g., Padmount and Vent Pipe or above ground structures). Standards publications were completed.
2) Engineering requested new requirement to capture fault direction due to multiple sources on Distribution grid. Power Delivery Products redesigned their firmware to meet SCE's new requirements. New firmware was successfully lab tested and new equipment (Smart Load Tracker – CT) were ordered to replace existing field installed.
3) Power Delivery Products developed a new method to capture voltage sensing on one position and multiplex to other positions. The new feature would minimize the installation complexity. The features were lab tested successfully and equipment were on ordered to replace existing field systems.
4) Submersible Applications - Due to harsh environment in vaults with seawater, stainless steel connectors would experience leakages and cause damages to its ports and conductors. New stainless steel connectors were evaluated and tested successfully in seawater with nitrate.

3M Electrical Market Division (Supplier-2):
1) 5 out of 10 systems experienced enclosure seawater leakage. Due to poor connector choice and sealing. 3M developed new stainless steel enclosure and stainless steel connectors.
2) Equipment would lock up (stop operating) several months after installation due to integrated systems instability. 3M is currently working to improve product stability.
3) Multiple firmware versions were implemented. Latest firmware was lab tested successfully but have not complete its field duration testing.

5. System Intelligence and Situational Awareness Capabilities

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution	
Objective & Scope: This project will demonstrate system intelligence and situation awareness capabilities such as high impedance fault detection, intelligent alarming, predictive maintenance, and automated testing. This will be accomplished by integrating intelligent algorithms and advanced applications with the latest substation automation technologies, next generation control systems, latest breakthrough in substation equipment, sensing technology, and communications assisted protection schemes, This system will leverage the International Electrotechnical Commission (IEC) 61850 Automation Standard and will include cost-saving technology such as process bus, peer-to-peer communications, and automated engineering and testing technology. This project will also inform complementary efforts at SCE aimed at meeting security and NERC CIP compliance requirements.		
Deliverables: 1- Intelligent Alarm processing stake-holders lab demonstration 2- Testing tools lab demonstration and hand over to production team 3- Process bus lab demonstration		
Metrics: 2a. Hours worked in California and money spent in California for each project 3a. Maintain / reduce operations and maintenance costs 3b. Maintain / reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5a. Outage number, frequency and duration reductions 5e. Utility worker safety improvement and hazard exposure reduction 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 8e. Stakeholders attendance at workshops 8f. Technology transfer		
Schedule: Q1 2016- Q4 2021		
EPIC Funds Encumbered: $336,915	**EPIC Funds Spent:** $2,203,003	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: 2019 Achievements Substation Test Tools: The Substation Demonstrations team worked with Triangle MicroWorks to advance SCE specific test scripts for use with their IEC 61850 substation simulation tool, known as Distributed Test Manager (DTM). Following a series of meetings where we provided feedback on pre-released versions of DTM, the major online release of DTM version 1.4 was made available in March 2019. When DTM v1.4 was made available online, the Substation Demonstrations team and Control & Meter Asset Engineering team tested the new version with various substation configurations. During this process, some issues were identified with the tool's workspace generation. We provided additional documentation and met with the vendor to troubleshoot throughout the remainder of the year. The Substation Demonstrations team met with other end users, such as the Substation Test School operators to demonstrate how DTM can be used in conjunction with the HMI to provide more in-depth and interactive training for HMI operation and functions. Process Bus: The Mayberry optical CT/process bus pilot was successfully commissioned in June 2019. Various stakeholders were involved in the process such as construction, technical support & strategy, protection and automation engineering, and substation engineering. This demonstrated SCE's first field installation of IEC-61850 technology. The next phase of process bus includes testing a full substation in our laboratory environment. Work has already commenced and a full design for a laboratory demonstration was completed in 2019. The design included input from various stakeholders such as protection and automation engineering and encouraged future thinking design considerations.

6. Regulatory Mandates: Submetering Enablement Demonstration - Phase 2

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Demand-Side Management
Objective & Scope: This project expands on the submetering project from the first EPIC triennial investment plan cycle to demonstrate plug-in electric vehicle (PEV) submetering at multi-dwelling and commercial facilities. Specifically, the project will leverage third party metering to conduct subtractive billing for various sites, including those with multiple customers of record.	
Deliverables: • Manual subtractive billing procedure for multiple customers of record • 3PE final report • PEV submetering protocol • Final project report	
Metrics: 1d. Number and percentage of customers on time variant or dynamic pricing tariffs	

1h. Customer bill savings (dollars saved) 3e. Non-energy economic benefits 4a. GHG emissions reductions (MMTCO2e) 6a. The 3rd Party Evaluator, Nexant, in collaboration with the Energy Division and IOUs, will develop a set of metrics for Phase 2 to be included in the final report 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 7j. Provide consumers with timely information and control options (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8e. Stakeholders attendance at workshops 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the marketplace (when known)		
Schedule: Q4 2015 – Q1 2019		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,211,829	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		

Status Update: The Final Report for the Regulatory Mandates: Submetering Enablement Demonstration - Phase 2 is complete, is being submitted with the 2019 Annual Report, and will be posted on SCE's public EPIC web site.

7. Bulk System Restoration Under High Renewables Penetration

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Transmission	
Objective & Scope: The Bulk System Restoration under High Renewable Penetration Project will evaluate system restoration plans following a blackout event under high penetration of wind and solar generation resources. Typically, the entire restoration plan consists of three main stages; Black Start, System Stabilization, and load pick-up. The Project will be divided into two phases: * Phase I of the project will address the feasibility of new approaches to system restoration by reviewing the existing system restoration plans and it's suitability for higher penetration of renewable generation. It will include a suitable RTDS Bulk Power system to be used in the first stage of system restoration, black start, and it will also include the modeling of wind and solar renewable resources. * Phase II of the project will focus on on-line evaluation of restoration plans using scenarios created using (RTDS) with hardware in the loop such as generation, transformer and transmission line protective relays. The RTDS is a well-known tool to assess and evaluate performance of protection and control equipment. This project intends to utilize the RTDS capabilities to evaluate and demonstrate system restoration strategies with variable renewable resources focusing on system stabilization and cold load pick-up. Furthermore, alternate restoration scenarios will be investigated. After the restoration process is evaluated, tested, and demonstrated in the RTDS Lab environment, we will provide a recommendation to system operations and transmission planning for their inputs to further develop this approach into an actual operational tool.		
Deliverables: N/A		
Metrics: N/A		
Schedule: N/A		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $42,193	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: In December 2016, this project was cancelled by SCE Senior Leadership as a result of internal organizational change that focused the organization on Distribution System strategic objectives. This was reported in the 2016 EPIC Annual Report.

8. Series Compensation for Load Flow Control

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Transmission
Objective & Scope: The intent of this project is to demonstrate and deploy the use of Thyristor Controlled Series Capacitors (TCSC) for load flow control on series compensated transmission lines. On SCE's 500 kV system in particular, several long transmission lines are series-compensated using fixed capacitor segments that do not support active control of power flow. The existing fixed series capacitors use solid state devices as a protection method and are called Thyristor Protected Series Capacitors (TPSC).	
Deliverables: N/A	

Metrics: N/A		
Schedule: N/A		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $5,920	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: In 2016, it was determined that the deliverables for this project could readily be accomplished via another project that was already in progress. Therefore, we ultimately determined that the project should be cancelled. This was discussed in SCE's 2016 Annual EPIC Report.		

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

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution
Objective & Scope: This project demonstrates the electrification of transportation and vocational loads that previously used internal combustion engines powered by petroleum fuels in the SCE fleet. The VAPS system uses automotive grade lithium-ion battery technology (Chevrolet Volt and Ford Focus EV) which is also used in notable stationary energy storage projects (Tehachapi 32 MWh Storage).	
Deliverables: **Light Duty VAPS Platform – PHEV Pickup Truck:** Purchase Order for PHEV Truck, Test Result Report, Final Report **Class 8 PHEV/BEV:** Purchase Order for Class 8 PHEV/BEV, Test Result Report, Final Report **Medium Duty VAPS Platform – Class 5 PHEV 9ft. Flatbed:** A Plug-in Hybrid Ford F550 Flatbed, Test Result Report, Final Report Small, Medium and Large VAPS Systems: Purchase Order for Small VAPS, Year-end Report, Purchase Order for Medium/Large VAPS, Test Result Report, Final Project Report, New Fleet VAPS System Report	
Metrics: 3a. Maintain/Reduce operations and maintenance costs 3e. Non-energy economic benefits 4a. GHG emissions reductions (MMTCO2e) 4b. Criteria air pollution emission reductions 5d. Public safety improvement and hazard exposure reduction	

5e. Utility worker safety improvement and hazard exposure reduction 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 8f. Technology transfer
Schedule: Q3 2015 – Q1 2019

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,147,298

Partners: N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: The Final Report for the VAPS is complete, is being submitted with the 2019 Annual Report, and will be posted on SCE's public EPIC web site.

10. Dynamic Power Conditioner

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

Objective & Scope: This project will demonstrate the use of the latest advances in power electronics and energy storage devices and controls to provide dynamic phase balancing. The project will also provide voltage control, harmonics cancellation, sag mitigation, and power factor control while fostering steady state operations such as injection and absorption of real and reactive power under scheduled duty cycles or external triggers. This project aims to mitigate the cause of high neutral currents and provide several power quality benefits by using actively controlled real and reactive power injection and absorption.
Deliverables: • Complete Specification documents for hardware • Use Cases • Lab Test Report of the Dynamic Power Conditioner • Final Project Report Presentation of project detailed findings and results. Final Report on effectiveness of device in the lab including a summary of all data collected and how the data may be accessed.
Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1i. Nameplate capacity (MW) of grid-connected energy storage 2. Job creation

3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 5a. Outage number, frequency and duration reductions 5b. Electric system power flow congestion reduction 5f. Reduced flicker and other power quality differences 7a. Description of the issues, project(s), and the results or outcomes 9. Adoption of EPIC technology, strategy, and research data/results by others
Schedule: Q3 2016 – Q3 2020

EPIC Funds Encumbered: $257,556	**EPIC Funds Spent:** $829,143

Partners: N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: 2019 Achievements The DER Demonstrations Group continued to collaborate with Siemens Industry/Fluence to revise the inverter specifications to make sure that the system did not exceed the limits outlined in the interconnection application. The changes requested were to change the Energy Storage System apparent power rating change from 300 kVA to 250 kVA and modify the winding ratio of the transformer. Once this request was made, Siemens/Fluence informed SCE that the container manufacturer would take longer to perform necessary modifications to accommodate EPC Power inverter, pushing installation from early April 2019 to the end of the 3rd Quarter of 2019. In the 4th Quarter of 2019, the installation of the system at the Pomona Lab Facility was completed. The system was also commissioned in late December, but the final acceptance criteria must be completed before operational status is achieved. Once the system is operational, this project will demonstrate and evaluate the maturity of inverter technology that implements dynamic load balancing functionality. The project plans also encompass verifying that the DPC is capable of absorbing and/or injecting active power to individual phases to achieve balancing at all 3-phases. Finally, the project will evaluate the potential for this new inverter architecture to reduce the energy /footprint requirement of a deployed Ener+AE24gy Storage system.

11. Optimized Control of Multiple Storage Systems

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

<table>
<tr><td colspan="3">This project aims to demonstrate the ability of multiple energy storage controllers to integrate with SCE’s Distribution Management System (DMS) and other decision-making engines to realize optimum dispatch of real and reactive power based on grid needs.</td></tr>
<tr><td colspan="3">Deliverables:
N/A</td></tr>
<tr><td colspan="3">Metrics:
N/A</td></tr>
<tr><td colspan="3">Schedule:
N/A</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$0</td><td>EPIC Funds Spent:
$140,482</td></tr>
<tr><td colspan="3">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td>Match Funding split:
N/A</td><td>Funding Mechanism:
N/A</td></tr>
<tr><td colspan="3">Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="3">Status Update:
In 2017, SCE concluded that the principal goals of this project could be accomplished in substantial part through the EPIC II Regional Grid Optimization Demo Phase 2 project (otherwise known as Integrated Grid Project (IGP) Phase 2). This project was cancelled, and SCE anticipates that the proposed benefits will be substantially realized through the IGP Phase 2 project.</td></tr>
</table>

12. DC Fast Charging Demonstration

<table>
<tr><td>Investment Plan Period:
2nd Triennial Plan (2015-2017)</td><td>Assignment to value Chain:
Demand-Side Management</td></tr>
<tr><td colspan="2">Objective & Scope:
The goal of this project is to demonstrate public DC fast charging stations at SCE facilities near freeways in optimal locations to benefit electric vehicle miles traveled (eVMT) by plug-in electric vehicles (PEVs) while implementing smart grid equipment and techniques to minimize system impact. The Transportation Electrification (TE) Organization is actively pursuing several strategic objectives, including optimizing TE fueling from the grid to improve asset utilization. Deploying a limited number of fast charging stations at selected SCE facilities that are already equipped to deliver power at this level (without additional infrastructure upgrade) will support this objective. The project will leverage SCE’s vast service territory and its facilities to help PEV reach destinations that would otherwise be out of range.</td></tr>
<tr><td colspan="2">Deliverables:
Final Report</td></tr>
<tr><td colspan="2">Metrics:
3a. Maintain/Reduce operations and maintenance costs
5b. Electric system power flow congestion reduction</td></tr>
</table>

5h. Reduction in system harmonics 8d. Number of information sharing forums held 8e. Stakeholders attendance at workshops 8f. Technology transfer		
Schedule: Q1 2016 – Q1 2018		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $21,945	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: The Final Report for the DC Fast Charging Demonstration is complete, was submitted with the 2018 Annual Report, and is posted on SCE's public EPIC web site.		

13. Integrated Grid Project II

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Cross-Cutting/Foundational Strategies & Technologies
Objective & Scope: The project will deploy, field test and measure innovative technologies that emerge from the design phase of the Integrated Grid Project (IGP) that address the impacts of DER (distributed energy resources) owned by both 3rd parties and the utility. The objectives are to demonstrate the next generation grid infrastructure that manages, operates, and optimizes the distributed energy resources on SCE's system. The results will help determine the controls and protocols needed to manage DER, how to optimally manage an integrated distribution system to provide safe, reliable, affordable service and also how to validate locational value of DERs and understand impacts to future utility investments.	
Deliverables: • Evaluation of system performance and field operations performance • Report on market maturity of technologies demonstrated • Final project report (Phase 2)	

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

7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market)
Schedule: Q3 2016 – Q3 2020

EPIC Funds Encumbered: $1,765,137	**EPIC Funds Spent:** $15,154,434

Partners: The CEC and DOE on the EASE ENERGISE project (part of the DOE Sunshot program).

Match Funding: $2.3M Cost Share	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: 2019 Achievements: The project demonstrated and tested a new control system that monitored and operated multiple DERs under various conditions. 1) IGP (Integrated Grid Project) Controllers a) Completed QAS Environment integration testing (March 2019), included testing with the following: i) PCCs (Programmable Capacitor Controllers) ii) FAN (Field Area Network) radios iii) DESI-2 Battery b) Completed QAS Environment Formal Test Cases (April 2019) c) Completed QAS Environment Test Report (June 2019) d) Completed Demo D Close Out Report to CPUC (July 2019) 2) APS (Adaptive Protection System) 2019 Overview: Executed a pilot program to demonstrate the feasibility of adjusting the settings of protective devices. Note – The pilot program was conducted in 2018. The final reporting for this program was conducted in early 2019. a) Completed Final Project Report (January 2019) b) Final Project Report utilized by other programs, including Grid Modernization (on-going)

3) EPRI (Electrical Power Research Institute)
2019 Overview: SCE's project scope was to support EPRI with the testing of new technologies related to energy storage that connects to the utility transmission system, distribution system, and customer premises.
a) Completed Laboratory Set Up, Test Plans, and Procedures (August 2019)
b) Completed Laboratory Testing of Smart Solar PV Inverter, including the following: (October 2019)
i) Undervoltage Support
ii) Overvoltage Support
c) Final Project Report (ECD: December 2019)

4) NODES NREL (National Renewable Energy Laboratory)
2019 Overview: SCE's project scope was to support NREL by developing the HIL (Hardware In the Loop) test plan, developing test cases, and performing HIL testing across multiple circuits.
a) Working on Task 5, which is HIL and large-scale simulation testing
b) Completed System Implementation Architecture (March 2019)
c) Completed Distributed Optimization Controller model (June 2019)
d) Completed Set Up / Communication on Titanium Feeder for testing (August 2019)

5) NODES GE (General Electric)
2019 Overview: SCE's project scope was to collaborate with GE, and other team members, to quantify demand response enablement and operating costs. Other support to GE included the design of a scalable load control system, and assistance with a Tech-2-Market strategy
a) Working on completion of Demand Response (ECD: December 2019)
b) Working on assistance to GE for Commissioning and Integration Testing of Advanced Load
Control (ECD: December 2019)
c) Working on assistance to GE to help bring this technology to the marketplace
d) Final Project Report (ECD: December 2019)

6) IGA (Integrated Grid Analytics) – First Phase
2019 Overview: Execute the Proof of Concept, as it relates to the identification, development, and validation of technologies that enable higher levels of renewables penetration
a) Completed Requirements Analysis and Design (July 2019)
b) Completed DERMS (Distributed Energy Resources Management System) reference software
architecture adjustments (August 2019)
c) Completed Demonstration, Verification, and Evaluation (3 Use Cases) (October 2019), including the
following:
i) Baseline Load Forecast Model
ii) Baseline Solar Forecast Model
d) Final Project Report (ECD: December 2019)

e) Final Project Report utilized in multiple industry publications (ECD: December 2019) 7) DOE EASE 2019 Overview: Completed demonstrations of DER self-provisioning into the DERMS system with hardware-in-the-loop (HIL), scalability of the DER registration and control system, and validated technologies that support distribution circuit constraint and net load management as well as hosting capacity improvement with high DER penetration scenarios in the lab. a) Completed Budget Period 1 i) Task 4.0: Self-Provisioning of PV and DER Assets (Completed January 2019): Test report submitted with satisfactory completion of use case 2 and Task 4. b) Completed Budget Period 2 i) Task 5.0: Advanced Distribution Controls for High-Penetration PV to Increase Hosting Capacity – HIL Testing (Completed September 2019): Demonstration included scalability to 10,000 virtual DERs and functions outlined in the DERMS use cases 2. Test report submitted with satisfactory results completing Task 5. c) Budget Period 3 (ECD: December 2021) i) Task 6.0: DER Services in Support of High-Penetration PV Scenarios – DSO Commercial Considerations and Testing (Started October 2019; ECD: September 2020) ii) Task 7.0: Cyber Security Recommendation and Risk Remediation of Third-Party Aggregator Integration to the Utility (Started October 2019; ECD: September 2020)

(3) 2018 – 2020 Triennial Investment Plan Projects

1. Advanced Comprehensive Hazards Tool

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Grid Operations/Market Design
Objective & Scope: This project will demonstrate a new and innovative approach to integrate emerging and mature hazard assessment tools. This demonstration will use a centralized data architecture that integrates various types of SCE asset data from non-electric, generation, and grid infrastructure. The project aims to identify vulnerabilities across different types of infrastructure to understand the overall risk to the grid. The project will demonstrate hazard scenarios and the impacts of those scenarios to the SCE system.	
Deliverables: • Use Cases • Use case test plan and results • Software application • Project final report	
Metrics:5d. Public safety improvement and hazard exposure reduction. 5e. Utility worker safety improvement and hazard exposure reduction 5a. Reduction in outage durations	
Schedule: Q3, 2019 – Q3, 2021	

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $39,658	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update This project is in the Execution phase.		

2. Advanced Data Analytics Technologies (ADAT)

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Grid Operations/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, 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.		
Deliverables: • Use Case document • Predictive model(s) and user guide • Final project report		
Metrics: 4e. Waste reductions 5a. Outage number, frequency and duration reductions 5d. Public safety improvement and hazard exposure reduction 7a. Description of the issues, project(s), and the results or outcomes 8f. Technology transfer		
Schedule: Q3, 2019 – Q4, 2021		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $31,613	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update This project is in the Execution phase.

3. Advanced Technology for Field Safety (ATFS)

<table>
<tr><td colspan="2">Investment Plan Period:
3rd Triennial Plan (2018-2020)</td><td colspan="2">Assignment to value Chain:
Distribution</td></tr>
<tr><td colspan="4">Objective & Scope:
This project will demonstrate the possibility of using new advanced technologies to reduce T&D field crew to customer hazards. The project will evaluate technologies that are capable of using data sources such as field sensors, smart meters, etc. to provide real/near real-time status of faulty equipment. Another area that this project will evaluate are the technologies that are capable of levering recent advancements in the Augmented Reality space.</td></tr>
<tr><td colspan="4">Deliverables:
Demonstration Plans for Advanced Technology for Field Safety
Requirements for SCE Augmented Reality Application
Integrated System Design and Test Plans
Document detailing demonstration test findings and results, including data obtained
Internal Stakeholder Engagement
Annual Reports
Final Project Report</td></tr>
<tr><td colspan="4">Metrics:
2a. Hours worked in California and money spent in California for each project
3a. Maintain / Reduce operations and maintenance costs
5e. Utility worker safety improvement and hazard exposure reduction
8f. Technology transfer</td></tr>
<tr><td colspan="4">Schedule:
Q3 2019 - Q4 -2022</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$0</td><td colspan="2">EPIC Funds Spent:
$41,050</td></tr>
<tr><td colspan="4">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td colspan="2">Match Funding split:
N/A</td><td>Funding Mechanism:
N/A</td></tr>
<tr><td colspan="4">Treatment of Intellectual Property
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="4">Status Update
This project is in the Execution phase.</td></tr>
</table>

4. Control and Protection for Microgrids and Virtual Power Plants

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Distribution
Objective & Scope: This project will examine control and protection schemes for safe and reliable operation of distribution systems with customer owned nested microgrids (MGs) and virtual power plants (VPPs). Standardized control and protection schemes and streamlined operation practices will be designed to support the integrity of the grid and to facilitate grid operation in the new context with high penetration of renewable resources and highly variable loads.	

Deliverables:
• Network studies and reports, which include load flow and protection coordination for the candidate Microgrid project(s).
• Design, implement, and document a Lab based Microgrid Test bed, field demonstrate the developed Microgrid Controls for the candidate Microgrid projects(s).
• Documented Use Case scenarios, with Microgrid functional and nonfunctional Requirements. Microgrid Cybersecurity protection will be included.
• A Final Test plan Report, which will include lab tests, software and hardware testing, end-to-end testing, and field testing.
• A Final Report documenting the candidate Microgrid, which will include:
  o Microgrid Control Design, prototypes, and simulations
  o Microgrid design variations, stating advantages, disadvantages, along with some optional basic cost analysis
  o Equipment requirements.
• Create Presentations for knowledge transfer including at least one conference presentation.	

Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1h. Customer bill savings (dollars saved) 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 3h. Energy Security (reduced energy and energy-related material imports) 5a. Outage number, frequency and duration reduced. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7a. Description of the issues, project(s), and the results or outcomes 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)	

7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360) 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360) 7j. Provide consumers with timely information and control options (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8e. Stakeholders attendance at workshops 8f. Technology transfer
Schedule: Q3 2019 – Q4 2023

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $41,050

Partners: N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update This project is in the Planning phase.

5. Cybersecurity for Industrial Control Systems

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Grid Operations/Market Design

Objective & Scope: This project will demonstrate the ability to deploy adaptive security controls and dynamically re-zone operational networks while the Industrial Control System (ICS) is either under cyberattack or subject to an increased threat level. The concept of dynamic zoning allows for isolation of threats to certain segments of the ICS and could include both vertical (isolating data flows from SCADA masters to substation endpoints) and horizontal (containing data flows between substations, for example, under a state of manual control when the SCADA master cannot be trusted).
Deliverables: • Environment design (design document of lab space for demonstration) • Unified use case demonstration of all 4 use cases at the same time. • Final project report

Metrics: Decrease mean time to completion of disconnecting grid communications in response to a simulated cyber incident 2. Demonstrate the viability of segmenting mesh networks 3. Demonstrate the viability of commercial orchestration and automation tools in a grid control / operational technology environment		
Schedule: Q4, 2018 – Q3, 2022		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $242,089	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update This project is in the Planning phase.		

6. Distributed Cyber Threat Analysis Collaboration

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Grid Operations/Market Design
Objective & Scope: This project will demonstrate the ability to standardize utility cybersecurity threat analysis by developing a Distributed Cyber Threat Analysis Collaboration framework to conduct local utility, collaboration with utility peers and sharing with National analysis centers to support expedient cyber threat feed analysis. This framework will demonstrate the capability to effectively consume internal and external sourcing threat feeds, process them for legitimacy, and identify utility risk impact, potential response measures through collaboration with utility peers and National analysis centers to validate and verify threats as well as significantly shorten the time needed to respond to a cyber compromise of the electric grid.	
Deliverables: • Environment design (design document of virtual lab space for demonstration) • Final project report	
Metrics: Mean duration of vulnerability response: Shorten the duration from reported grid vulnerability to executing a response or plan. 2. Mean duration of intelligence sharing: Shorten the time from receiving threat intelligence, to sharing with internal affected business units and external vetted partners 3. Mean duration of cybersecurity defense response: Shorten the time between recognition, sharing, and executing a response to a cybersecurity threat on SCE's grid systems or technologies	

Schedule: Q4, 2018 – Q2, 2022		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $93,254	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update This project is in execution.		

7. Distributed Energy Resources Dynamics Integration Demonstration

Investment Plan Period: 3rd Triennial Plan (2018-2020)	Assignment to value Chain: Distribution
Objective & Scope: This project aims to evaluate the two key technical challenges related to high DER penetration namely protection system impacts and adverse interactions between multiple types of DERs. •The project will be comprised of both hardware and software components: solar PV inverters, a lab testbed, and computer models of: inverters, synchronous and induction generators, protective relay and one SCE sample feeder. •Test smart inverter functional capabilities on SCE distribution feeder with high DER penetration levels, it will be able to establish DER Operating Standards and leverage Smart Inverters for System-wide reliability. •Develop interoperable controls capability at SCE to provide flexibility to the operation of the grid.	
Deliverables: • Use Case • PSCAD Model • PSCAD simulation documentation • Final project report	
Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 7a. Description of issues resolved that prevented widespread deployment of technology or strategy and the results or outcomes 8b. Effectiveness of information dissemination by the number of reports and fact sheets published online	

Schedule: Q3, 2019 – Q1, 2023		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $39,527	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update This project is in execution.		

8. Distributed PEV Charging Resources

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Demand-Side Management
Objective & Scope: 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, 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 concern utility planning and could also challenge high deployment of such systems due to their low load factor and potentially alarming bill impact to customers under current tariffs. Combining fast charging systems with energy storage can result in 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 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.	
Deliverables: • Develop and publish specific recommendations for integrated fast charger/ESS including potential options for incorporation of second-use batteries • Procure, test, evaluate, and document the Lab/Field demonstration of fast charging systems coupled with energy storage systems.	

• Demonstrate methods by which SCE could manage ESS to support the grid and customer fast charging applications, including: o Customer bill management, such as automatic TOU rates o Demand Response (DR) applications (reducing or shifting loads) o Voltage support applications • Create a Final Report as well as Presentations for knowledge transfer including at least one conference presentation.		
Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1e. Peak load reduction (MW) from summer and winter programs 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 3h. Energy Security (reduced energy and energy-related material imports) 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7a. Description of the issues, project(s), and the results or outcomes 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360) 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360) 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8e. Stakeholders attendance at workshops 8f. Technology transfer		
Schedule: Q3 2019 – Q4 2023		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $44,901	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update This project is in planning.

9. Distribution Primary & Secondary Line Impedance

Investment Plan Period: 3rd Triennial Plan (2018-2020)		**Assignment to value Chain:** Distribution
Objective & Scope: This project will examine the possibility of establishing primary and secondary line impedance information for distribution circuits, by examining the voltage and power signatures at the meter and transformer level, by leveraging a basic connectivity model of the circuits and utilizing SCADA data. The availability of complete primary line impedance information can result in accurate load flow / distribution state estimation results and greater real time management of the distribution grid and greater utilization of capacity within the existing installed infrastructure before new assets deemed to be required.		
Deliverables: • Distribution Network Phasing Prediction Algorithm • Distribution Network Connectivity Phasing Prediction Algorithm • Distribution Network Primary Impedance Prediction Algorithm		
Metrics: 3c. Reduction in electrical losses in the transmission and distribution system 3e. Non-energy economic benefits – this project, if successful, will allow SCE to plan and operate the grid		
Schedule: Q3 2019 - Q3 2021		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $54,015	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update This project is in planning.		

10. Power System Voltage and VAR Control Under High Renewables Penetration

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Distribution
Objective & Scope:	

This project will demonstrate in a lab setting the effect of a Voltage & VAR management and control algorithm that optimizes the operation of the power grid, for both the transmission and distribution systems, by regulating voltage and controlling VAR resources optimally while maintaining the secure operation of the power grid.
Deliverables: • Inverter Based Resource Models • Blackstart Methodology and Approach • HIL Test Protocols • Testing Results & Final Report
Metrics: 1i. Nameplate capacity (MW) of grid-connected energy storage 3a. Maintain / Reduce operations and maintenance costs 4a. GHG emissions reductions (MMTCO2e) 5a. Outage number, frequency and duration reductions 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)
Schedule: Q3 2019 – Q3 2022

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $62,474

Partners: N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update This project is in execution.

11. SA-3 Phase III Field Demonstrations

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Transmission

Objective & Scope: The Project aims to successfully demonstrate a modern substation automation systems for transmission substation by adopting scalable technology that enables advanced functionality to meet NERC CIP compliance and IT cybersecurity requirements. This project is designed to provide measurable engineering, operations, and maintenance benefits through improved cybersecurity and reliability for transmission substations. It will also provide interoperability and allow the system to work with relays from multiple vendors. Finally the project should help prevent vendor "lock-in" due to restrictions based on proprietary software and hardware, and assure that SCE has the flexibility to implement the best solution available.
Deliverables:

• Demonstration Plans • Detailed use cases, demonstration scripts, measurement and validation (M&V) plans. • Documents detailing demonstration test findings and results • Annual Reports • Final Project Report
Metrics: 2a. Hours worked in California and money spent in California for each project X 3a. Maintain / Reduce operations and maintenance costs X 3b. Maintain / Reduce capital costs X 6a. Avoiding technology obsolescence 7a. Description of the issues, project(s), and the results or outcomes
Schedule: Q2-2019 – Q4-2023

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $62,060

Partners: N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update This project is in execution.

12. Service Center of the Future

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Demand-Side Management

Objective & Scope: This project will demonstrate an advanced SCE service center housing electrified utility crew trucks, together with employee workplace charging, connected to a local service area with high penetration of distributed solar generation and plug-in electric vehicles. The electrification of transportation at the service center will be conducted in a way that does not adversely impact the local system, and also interacts with the system using vehicle-grid integration (VGI) technology to help ensure reliable and stable service at both the service center and local area. This project will deploy electrified utility trucks and utility and workplace EVSE with advanced VGI communications and controls to receive and respond to both DR (direct) and SCE grid (dynamic) signals to foster reliable charging and support the local grid's stability. The vehicle systems, when not driving, can be used as grid assets and respond directly to support system voltage and stabilize demand. The two-front approach leverages the operating characteristics of both fleet trucks (charge during p.m.) and employee vehicles (charge in a.m.).

The Project’s objective will be to evaluate the ability to fully electrify a fleet service center with building electrification technologies (e.g., space and water heating), EVSEs and employee charging while managing any associated impacts to the local grid system. The results could inform future efforts to electrify other service centers, while also supporting commercial customer electric vehicle loads.

Deliverables:
• A documented lab/field evaluation and demonstration of:
  o Systems to manage customer EV charging loads
  o An EV charging sub-metering system
  o A conversion of a gas/electric building to full electric and integration with site controls
  o A technical solution for integration of Service Center systems into SCE's GMS and Grid Interconnection Planning Tool (GIPT)
  o A customer resiliency solution for EV Charging using energy storage
  o Including recommendations for enhanced GMS capabilities (services, interfaces, etc.) for similar charging-based management systems.
• A Final report showing results and providing recommendations to enable further deployment of such facilities as well as Presentations for knowledge transfer including at least one conference presentation.

Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1h. Customer bill savings (dollars saved) 1i. Nameplate capacity (MW) of grid-connected energy storage 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5a. Outage number, frequency and duration reductions 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7a. Description of the issues, project(s), and the results or outcomes 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)

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

Schedule: Q3 2019 – Q4 2023		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $43,931	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update This project is in planning.		

13. Smart Cities

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Distribution
Objective & Scope:	

The project will demonstrate the electric utility role within a Smart City initiative. The demonstration would seek to meet the following objectives: (a) increasing coordination between electric system and urban planning, (b) coordinating infrastructure construction activities within a City, (c) streamlining the interconnection process through automated systems between SCE and the City, (d) partnering with cities to engage more customers in renewable resources (e.g., Community Solar PV, Community Storage) and creating more opportunities for electric transportation, (e) working with cities to customize their resource portfolio to meet a Climate Action Plan goal (e.g., "Community Choice Aggregation Lite" or Community Choice Aggregation), (f) leveraging assets (e.g., Telecommunications, Right of Ways), (g) coordinating communication on energy programs (e.g., Energy Efficiency, Demand Response, Charge Ready, Green Rate), and (h) assisting large customers (i.e., the City as an energy customer) in more efficiently utilizing their energy resources and improving resiliency for critical operations center (e.g., emergency command centers).

Deliverables:
• Deploy a front of the meter Microgrid to power a significant portion of customer essential facility loads leveraging on-site renewable DERs (e.g., solar, energy storage) during outages, thus enhancing grid and customer resiliency.
• Design, implement, and document a Lab as well as a field demonstration for the candidate customer Microgrid project including:
  o Evaluate installation of SCE owned energy storage to support Microgrid operation using black-start and islanding capability.
  o Evaluate electric vehicles (e.g., electric school bus) to serve as energy storage.
• Demonstrate broadcasting events to customer DERs (solar+storage) to maximize value of DERs in an outage using communication protocol such as IEEE 2030.5.
• Create a Final Report as well as Presentations for knowledge transfer including at least one conference presentation.

Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1i. Nameplate capacity (MW) of grid-connected energy storage 3e. Non-energy economic benefits 3h. Energy Security (reduced energy and energy-related material imports) 5a. Outage number, frequency and duration reductions 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 5i. Increase in the number of nodes in the power system at monitoring points 7a. Description of the issues, project(s), and the results or outcomes 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)

7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360) 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 7j. Provide consumers with timely information and control options (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8e. Stakeholders attendance at workshops 8f. Technology transfer 9a. Description/documentation of projects that progress deployment, such as Commission approval of utility proposals for widespread deployment or technologies included in adopted building standards 9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs
Q3 2019 – Q4 2023

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $47,872	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update This project is in planning.		

14. Storage-Based DC Link

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Distribution
Objective & Scope: This project will examine the benefits of a novel architecture for a distribution-connected energy storage system. Where typically storage systems are connected to a single electrical point, this architecture will allow the system to connect to two unique distribution circuits, through the use of two power conversion systems, tied to a single storage medium. This approach will allow the storage system to support both circuits, individually or simultaneously, and will also provide a means of dynamically exchanging power between the two circuits (DC link).	
Deliverables: • Demonstration Plans • Documented results outlining key insights and potential fatal flaws	

• Integrated System Design and Test Plans • System Test Results • Demonstration Results • Annual Reports • Final Project Report
Metrics: 2a Total electricity deliveries from grid-connected distributed generation facilities 1e. Peak load reduction (MW) from summer and winter programs 2a. Hours worked in California and money spent in California for each project 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 5a. Outage number, frequency and duration reductions 5f. Reduced flicker and other power quality differences 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning (PU Code § 8360) 8b. Number of reports and fact sheets published online
Schedule: Q2 2019 – Q4 2021

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $43,293

Partners: N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update This project is in execution.

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

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Demand-Side Management
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 when there's an outage on the grid.	

The Project will assess and evaluate, in a laboratory environment the following: the proposed V2G-AC Rule 21 interconnection processes, proposed SAE and UL standards, and the function of automaker OEM battery/inverter systems to support vehicle-grid integration (VGI) services, integration of project 3rd party aggregators with SCE's Grid Management System (GMS)/DER Management Systems (DERMS), and partnership with an existing Rialto Unified School District DOE V2G school bus project (and its Charge Ready Transport application) to provide an interconnection pathway by demonstrating functional requirements in the lab and the field evaluation of deployed systems.

Deliverables:
• Provide an evaluation and demonstration plan of bidirectional on-board inverters based on Rule 21 proposed updates, automaker input, SAE standards works, and UL standards
• With auto OEMs and school bus OEM, conduct and document lab tests of systems connected with EVSE infrastructure under test protocols to meet expected certification requirements (at system level)
• Complete and document a field implementation of all elements and conduct the demonstration with Blue Bird school bus in conjunction with DOE V2G project (Rialto USD site)
• Demonstrate and document:
  o A technical solution for integration into SCE's Grid Management System
  o The use of EV battery systems to support EV charging during grid outage conditions
• Create a Final report, including draft input for new standards updates, Rule 21, SAE, UL, IEEE as well as Presentations for knowledge transfer including at least one conference presentation.

Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1e. Peak load reduction (MW) from summer and winter programs 1h. Customer bill savings (dollars saved) 1i. Nameplate capacity (MW) of grid-connected energy storage 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 3h. Energy Security (reduced energy and energy-related material imports) 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7a. Description of the issues, project(s), and the results or outcomes 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)

7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360) 7j. Provide consumers with timely information and control options (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8e. Stakeholders attendance at workshops 8f. Technology transfer 9a. Description/documentation of projects that progress deployment, such as Commission approval of utility proposals for widespread deployment or technologies included in adopted building standards 9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market)		
Schedule: Q3 2019 – Q4 2023		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $36,747	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update This project is in planning.		

16. Energy System Cybersecurity Posturing

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Grid Operations/Market Design
Objective & Scope: This project demonstration will automate the ability to probe the Utility's supervisory control and data acquisition system (SCADA), using an automated probing capability which will enable the system to report back on how it is configured. The ESCP project will engineer toolset to first demonstrate the capability to execute an automated system posture where cybersecurity and regulatory related system attributes will be collected and analyzed via a toolset. It will then demonstrate enhanced network communications situational awareness through a Software Defined Networking (SDN) interface with the capability to support cross cutting operations and cybersecurity analysis.	
Deliverables:	

N/A		
Metrics: N/A		
Schedule: N/A		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $12,134	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update This project is canceled.		

4. Conclusion

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

(1) 2012-2014 Investment Plan

For the period between January 1 and December 31, 2019, SCE expended a total of $799,100 toward project costs and $ $352,410 toward administrative costs for a grand total of $1,151,510. SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC program amount to $38,105,403. SCE committed $662,728 toward projects and encumbered $1,026,454 through executed purchase orders during this period. SCE has no uncommitted EPIC funding for this period.

SCE continued executing projects from its approved portfolio. SCE's EPIC I Portfolio consists of 16 projects; 3 of these projects were completed during the calendar year 2015, 4 projects were completed in 2016, 4 projects were completed in 2017, 2 projects were completed in 2018 and 1 project was completed in 2019.

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

1. Enhanced Infrastructure Technology Report;
2. Submetering Enablement Demonstration;

3. Dynamic Line Rating;
4. Distribution Planning Tool;
5. Beyond the Meter: Customer Device Communications Unification and Demonstration;
6. Portable End-to-End Test System
7. State Estimation Using Phasor Measurement Technologies;
8. Deep Grid Coordination (otherwise known as the Integrated Grid Project)
9. DOS Protection & Control Demonstration
10. Advanced Voltage and VAR Control of SCE Transmission
11. Outage Management and Customer Voltage Data Analytics Demonstration
12. Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)
13. Next Generation Distribution Automation, Phase 1
14. Wide Area Reliability Management and Control

Final project reports for project 14 is included in the Appendix of this annual report.

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

For the period between January 1 and December 31, 2019, SCE expended a total of $4,728,954 toward project costs and $14,778 toward administrative costs for a grand total of $4,743,732. SCE's cumulative expenses over the lifespan of its 2015 – 2017 EPIC program amount to 31,027,901. SCE committed $5,558,516 toward projects and encumbered $3,332,699 through executed purchase orders during this period. SCE has no uncommitted EPIC funding for this period. SCE continued executing projects from its approved portfolio. SCE's EPIC II Portfolio consists of 13 projects; 3 projects have been cancelled for reasons described in their respective project updates above, 1 project was completed during the calendar 2017, 3 projects were completed in 2018, and 2 projects were completed in 2019.

The list of completed 2015-2017 Investment Plan projects is shown below:

1. Advanced Grid Capabilities Using Smart Meter Data
2. DC Fast Charging
3. Proactive Storm Impact Analysis Demonstration
4. Integration of Big Data for Advanced Automated Customer Load Management
5. Versatile Plug-in Auxiliary Power System
6. Regulatory Mandates: Submetering Enablement Demonstration - Phase 2

(3) 2018-2020 Investment Plan

For the period between January 1 and December 31, 2019, SCE expended a total of $942,833 toward project costs and $488,729 toward administrative costs for a grand total of $1,431,562. Since year 2019 was the first year of implementing SCE's 2018 – 2020 Portfolio, the 2019 total also represents the cumulative expenses over the lifespan of the Portfolio. SCE committed $12,330,423 toward projects and encumbered $0 through executed purchase orders during this period. SCE has $27,557,539 uncommitted EPIC project funding for this period.

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

During calendar year 2020, SCE looks forward to engaging with the Commission and stakeholders on the EPIC successor program rulemaking. Additionally, SCE will continue to focus on successfully executing its single remaining approved project as part of its 2012 – 2014 Investment Plan as well as 4 approved projects as part of its 2015 – 2017 Investment Plan. SCE also intends to continue executing 7 projects, and launching additional waves of projects from its 2018 – 2020 Investment Plan. Key program implementation activities will include finalizing demonstration plans and requirement specifications, initiating new procurements, continuing technology deployments in SCE's field and lab environments, and executing rigorous testing, measurement, and verification processes.

Furthermore, SCE will participate in the Policy + Innovation Coordination Group (PICG). In an effort to improve program coordination among Administrators and further transparency, the PICG is planning Policy + Innovation Partnership Areas (PIPAs). SCE plans to actively participate in the development of the PIPAs.

SCE will continue its open dialogue with stakeholders through public engagements in 2020. In these public workshops, as well as the annual symposium, SCE and the other EPIC Administrators will update stakeholders regarding EPIC III projects prior to executing on such projects. SCE and the other EPIC Administrators will also explain key accomplishments achieved and learnings obtained from their respective EPIC programs.

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

During calendar year 2020, SCE will focus on successfully executing and closing out its single remaining approved project as part of its EPIC I Investment Plan. SCE will also continue to focus on successfully executing its 4 approved projects as part of its EPIC II Investment Plan. Moreover, SCE will continue executing its first wave of 7 projects, as well as launching additional tranches of projects, as part of its EPIC III Investment Plan. These EPIC demonstrations require integrating cybersecurity requirements; such integration issues caused significant project delays in 2019. Additional cyber on-site resources were brought on-board in late 2019 to help alleviate delays. Additionally, SCE has been working to further streamline and improve internal governance processes, which should spur more efficient execution of projects.

Appendix A

SCE EPIC Project Status Report Spreadsheet

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
2	Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
3	1st triennial (2012-2014)	SCE	**Integrated Grid Project** *Note: Previously referred to as Regional Grid Optimization*	Cross-Cutting/Foundational Strategies & Technologies	The project will demonstrate, evaluate, analyze and propose options that address the impacts of DER (Distributed Energy Resources) penetration and increased adoption of DG (Distributed Generation) owned by consumers on all segments/aspects of SCE's grid – transmission, distribution and overall "reliable" power delivery cost to SCE customers (all tiers). This demonstration project is in effect the next step to the ISGD project. Therefore, this analysis will focus on the effects of introducing emerging and innovative technology into the utility and consumer end of the grid, predominantly the commercial and industrial customers with the ability to generate power with self-owned and operated renewable energy sources, but connected to the grid for "reliability" and "stability" operational reasons. This scenario introduces the need for the utility (SCE) to assess discriminative technology necessary for stabilizing the grid with increased DG adoption, and more importantly, consider possible economic models that would help SCE adopt to the changing regulatory policy and GRC structures.	8/15/2012	No	Grid Operation/Market Design	$ -	$ -	$ 15,679,990	$ 1,745,543	$ 17,425,533	N/A
4	1st triennial (2012-2014)	SCE	**Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)**	Customer Focused Products and Services	The Beyond the Meter (BTM) project will demonstrate the use of a DER management system to interface with and control DER based on customer and distribution grid use cases. It will also demonstrate the ability to communicate near-real time information on the customer's load management decisions and DER availability to SCE for grid management purposes. Three project objectives include: 1) development of a common set of requirements that support the needs of a variety of stakeholders including customers, distribution management, and customer program; 2) validation of standardized interfaces, functionalities, and architectures required in new Rule 21 proceedings, IOU Implementation Guide, and UL 1741/IEEE 1547 standards; 3) collection and analysis measurement and cost/benefits data in order to inform the design of new tariffs, recommend the deployment of new technologies, and support the development of new programs.	8/15/2012	No	Demand-Side Management	$ -	$ -	$ 1,307,752	$ 170,397	$ 1,478,149	N/A
5	1st triennial (2012-2014)	SCE	**Voltage and VAR Control of SCE Transmission System**	Energy Resources Integration	This project involves the demonstration of software and hardware products that will enable automated substation volt/var control. Southern California Edison (SCE) will demonstrate a Substation Level Voltage Control (SLVC) unit working with a transmission control center Supervisory Central Voltage Coordinator (SCVC) unit to monitor and control substation voltage. The scope of this project includes systems engineering, testing, and demonstration of the hardware and software that could be operationally employed to manage substation voltage.	8/15/2012	No	Transmission	$ -	$ -	$ 595,575	$ 257,590	$ 853,165	N/A
6	1st triennial (2012-2014)	SCE	**State Estimation Using Phasor Measurement Technologies**	Cross-Cutting/Foundational Strategies & Technologies	Accurate and timely power system state estimation data is essential for understanding system health and provides the basis for corrective action that could avoid failures and outages. This project will demonstrate the utility of improved static system state estimation using Phasor Measurement Unit (PMU) data in concert with existing systems. Enhancements to static state estimation will be investigated using two approaches: 1) by using GPS time to synchronize PMU data with Supervisory Control and Data Acquisition (SCADA) system data; 2) by augmenting SCE's existing conventional state estimator with a PMU based Linear State Estimator (LSE).	8/15/2012	No	Grid Operation/Market Design	$ -	$ -	$ 739,331	$ 82,848	$ 822,179	N/A

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2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**Leveraged Funds**	**Partners**	**Match Funding**	**Match Funding Split**	**Funding Mechanism**	**Intellectual Property**	**Identification of the method used to grant awards.**	**If competitively selected, provide the number of bidders passing the initial pass/fail screening for project**	**If competitively selected, provide the name of selected bidder.**	**If competitively selected, provide the rank of the selected bidder in the selection process.**	**If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.**
3	1st triennial (2012-2014)	SCE	**Integrated Grid Project** *Note: Previously referred to as Regional Grid Optimization*	Cross-Cutting/Foundational Strategies & Technologies	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid (Request for Proposals): Enbala Power Networks; Integral Analytics, LLC; Directed Awards Issued to the Following Vendor(s): Corepoint 1, Inc; Pacific Coast Engineering; Optiv Security, Inc; Ramsey Electronics:	9	Integral Analytics Enbala	1st 2nd	Does not apply; Highest scoring bidders were selected for award.
4	1st triennial (2012-2014)	SCE	**Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)**	Customer Focused Products and Services	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid (Request for Proposals) & Directed Awards Directed Awards Issued to the Following Vendor(s): Autogrid Systems, Inc.; Qualitylogic, Inc.	2	Saker Systems, LLC	1	Does not apply; Highest scoring bidder was selected for award.
5	1st triennial (2012-2014)	SCE	**Voltage and VAR Control of SCE Transmission System**	Energy Resources Integration	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Siemens Industry, Inc; The Mathworks, Inc Nexant Inc	TBD	TBD	TBD	TBD
6	1st triennial (2012-2014)	SCE	**State Estimation Using Phasor Measurement Technologies**	Cross-Cutting/Foundational Strategies & Technologies	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Power World Corporation Electric Power Group, LLC	TBD	TBD	TBD	TBD

	A	B	C	D	Z	AA	AB	AC
2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.**	**Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?**	**How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals**	**Applicable metrics**
3	1st triennial (2012-2014)	SCE	**Integrated Grid Project** *Note: Previously referred to as Regional Grid Optimization*	Cross-Cutting/Foundational Strategies & Technologies	N/A; Applicable to CEC only.	@ Business, Inc.: California-based entity Bridgewater Consulting Group, Inc: California-based entity; Small Business; DBE Corepoint 1, Inc: California-based entity Pacific Coast Engineering: California-based entity; Small Business	N/A; Applicable to CEC only.	1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 1h. Customer bill savings (dollars saved) 1i. Nameplate capacity (MW) of grid-connected energy storage 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5a. Outage number, frequency and duration reductions 5b. Electric system power flow congestion reduction 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360); 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360); 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations
4	1st triennial (2012-2014)	SCE	**Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)**	Customer Focused Products and Services	N/A; Applicable to CEC only.	Saker Systems LLC: California-base entity; DBE Autogrid Systems, Inc: California-base entity Qualitylogic, Inc.: California-base entity	N/A; Applicable to CEC only.	1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5b. Electric system power flow congestion reduction 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360); 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360); 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360); 7g. Integration of cost-effective smart appliances and consumer devices (PU Code § 8360); 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360); 7j. Provide consumers with timely information and control options (PU Code § 8360); 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360); 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held.
5	1st triennial (2012-2014)	SCE	**Voltage and VAR Control of SCE Transmission System**	Energy Resources Integration	N/A; Applicable to CEC only.	Siemens Industry, Inc: California-based entity The Mathworks, Inc: N/A Nexant Inc - California- based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market).
6	1st triennial (2012-2014)	SCE	**State Estimation Using Phasor Measurement Technologies**	Cross-Cutting/Foundational Strategies & Technologies	N/A; Applicable to CEC only.	Power World Corporation: California-based entity Electric Power Group, LLC: California-based entity; Small Business; MBE	N/A; Applicable to CEC only.	6a. Enhanced grid monitoring and on-line analysis for resiliency 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9d. Successful project outcomes ready for use in California IOU grid (Path to market). 9e. Technologies available for sale in the market place (when known).

	A	B	C	D	AD	AE
2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**2019 Update**	
3	1st triennial (2012-2014)	SCE	**Integrated Grid Project** *Note: Previously referred to as Regional Grid Optimization*	Cross-Cutting/Foundational Strategies & Technologies	The final project report is complete, was submitted with the 2017 Annual Report, and is available on SCE's public EPIC web site.	
4	1st triennial (2012-2014)	SCE	**Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)**	Customer Focused Products and Services	The final project report is complete, was submitted with the 2017 Annual Report, and is available on SCE's public EPIC web site.	
5	1st triennial (2012-2014)	SCE	**Voltage and VAR Control of SCE Transmission System**	Energy Resources Integration	The final project report is complete, was submitted with the 2018 Annual Report, and is available on SCE's public EPIC web site.	
6	1st triennial (2012-2014)	SCE	**State Estimation Using Phasor Measurement Technologies**	Cross-Cutting/Foundational Strategies & Technologies	The final project report is complete, was submitted with the 2017 Annual Report, and is available on SCE's public EPIC web site.	

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2	Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
7	1st triennial (2012-2014)	SCE	**Distributed Optimized Storage (DOS) Protection & Control Demonstration**	Energy Resources Integration	This field demonstration will test end-to-end integration of multiple energy storage devices on a distribution circuit/feeder to provide a turn-key solution that can cost-effectively be considered for SCE's distribution system, where identified feeders can benefit from grid optimization and variable energy resources (VER) integration. To accomplish this, the project team will first identify distribution system feeders where multiple energy storage devices can be operated centrally. Once a feeder is selected, the energy storage devices will be deployed and tested to demonstrate seamless utility integration, control, and operation of these devices using a single centralized controller. At the end of the project, SCE will have established clear methodologies for identifying feeders that can benefit from distributed energy storage devices and will have established necessary standards-based hardware and control function requirements for grid optimization and renewables integration with distributed energy storage devices.	8/15/2012	No	Distribution	$ -	$ -	$ 7,208	$ 67,228	$ 74,436	N/A

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2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**Leveraged Funds**	**Partners**	**Match Funding**	**Match Funding Split**	**Funding Mechanism**	**Intellectual Property**	**Identification of the method used to grant awards.**	**If competitively selected, provide the number of bidders passing the initial pass/fail screening for project**	**If competitively selected, provide the name of selected bidder.**	**If competitively selected, provide the rank of the selected bidder in the selection process.**	**If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.**
7	1st triennial (2012-2014)	SCE	**Distributed Optimized Storage (DOS) Protection & Control Demonstration**	Energy Resources Integration	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD

	A	B	C	D	Z	AA	AB	AC
2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.**	**Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?**	**How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals**	**Applicable metrics**
7	1st triennial (2012-2014)	SCE	**Distributed Optimized Storage (DOS) Protection & Control Demonstration**	Energy Resources Integration	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	1c. Avoided procurement and generation costs 1i. Nameplate capacity (MW) of grid-connected energy storage 3b. Maintain / Reduce capital costs 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 6a. Benefits in energy storage sizing through device operation optimization 6b. Benefits in distributed energy storage deployment vs. centralized energy storage deployment 7a. Description of the issues, project(s), and the results or outcomes 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports.

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2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**2019 Update**	
7	1st triennial (2012-2014)	SCE	**Distributed Optimized Storage (DOS) Protection & Control Demonstration**	Energy Resources Integration	The final project report is complete, was submitted with the 2018 Annual Report, and is available on SCE's public EPIC web site.	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**A brief description of the project**	**Date of the award**	**Was this project awarded in the immediately prior calendar year?**	**Assignment to Value Chain**	**Encumbered Funding Amount ($)**	**Committed Funding Amount ($)**	**Funds Expended to date: Contract/Grant Amount ($)**	**Funds Expended to date: In house expenditures ($)**	**Funds Expended to date: Total Spent to date ($)**	**Administrative and overhead costs incurred for each project**
8	1st triennial (2012-2014)	SCE	**Dynamic Line Rating**	Grid Modernization and Optimization	Transmission line owners apply fixed thermal rating limits for power transmission lines. These limits are based on conservative assumptions of wind speed, ambient temperature and solar radiation. They are established to help ensure compliance with safety codes, maintain the integrity of line materials, and help secure network reliability. Monitored transmission lines can be more fully utilized to improve network efficiency. Line tension is directly related to average conductor temperature. The tension of a power line is directly related to the current rating of the line. This project will demonstrate the CAT-1 dynamic line rating solution. The CAT-1 system will monitor the tension of transmission lines in real-time to calculate a dynamic daily rating. If successful, this solution will allow SCE to perform real-time calculations in order to determine dynamic daily rating of transmission lines, thus increasing transmission line capacity.		No	Distribution	$ -	$ -	$ 399,045	$ 69,556	$ 468,601	N/A
9	1st triennial (2012-2014)	SCE	**Next-Generation Distribution Automation**	Grid Modernization and Optimization	SCE's current distribution automation scheme often relies on human intervention that can take several minutes (or longer during storm conditions) to isolate faults, is only capable of automatically restoring power to half of the customers on the affected circuit, and needs to be replaced due to assets nearing the end of their lifecycle. In addition, the self-healing circuit being demonstrated as part of the Irvine Smart Grid Demonstration is unique to the two participating circuits and may not be easily applied elsewhere. As a result, the Next-Generation Distribution Automation project intends to demonstrate a cost-effective advanced automation solution that can be applied to the majority of SCE's distribution circuits. This solution will utilize automated switching devices combined with the latest protection and wireless communication technologies to enable detection and isolation of faults before the substation circuit breaker is opened, so that at least 2/3 of the circuit load can be restored quickly. This will improve reliability and reduce customer minutes of interruption. The system will also have directional power flow sensing to help SCE better manage distributed energy resources on the distribution system. At the end of the project, SCE will provide reports on the field demonstrations and recommend next steps for new standards for next-generation distribution automation.	8/15/2012	No	Distribution	$ -	$ -	$ 3,096,838	$ 923,572	$ 4,020,410	N/A
10	1st triennial (2012-2014)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration**	Customer Focused Products and Services	On 11/14/13, the California Public Utilities Commission (CPUC) voted to approve the revised Proposed Decision (PD) Modifying the Requirements for the Development of a Plug-In Electric Vehicle Submetering Protocol set forth in D.11-07-029. The investor-owned utilities (IOUs) are to implement a two phased pilot beginning in May 2014, with funding for both phases provided by the Electric Program Investment Charge (EPIC). This project, Phase I of the pilot will (1) evaluate the demand for Single Customer of Record submetering, (2) estimate billing integration costs, (3) estimate communication costs, and (4) evaluate customer experience. IOU's and external stakeholders will finalize the temporary metering requirements, develop a template format used to report submetered, time-variant energy data, register Submeter Meter Data Management Agents and develop a Customer Enrollment Form, and finalize MDMA Performance Requirements. The IOUs will also solicit a 3rd party evaluator to evaluate customer experience.	8/15/2012	No	Demand-Side Management	$ -		$ 985,986	$ 148,614	$ 1,134,600	N/A

	A	B	C	D	O	P	Q	R	S	T	U	V	W	X	Y
2	Investment Program Period	Program Administrator	Project Name	Project Type	Leveraged Funds	Partners	Match Funding	Match Funding Split	Funding Mechanism	Intellectual Property	Identification of the method used to grant awards.	If competitively selected, provide the number of bidders passing the initial pass/fail screening for project	If competitively selected, provide the name of selected bidder.	If competitively selected, provide the rank of the selected bidder in the selection process.	If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.
8	1st triennial (2012-2014)	SCE	**Dynamic Line Rating**	Grid Modernization and Optimization	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid ((Request for Proposal) to the Following Vendor(s): 1- .... (Direct award) to the Following Vendor(s): 2-	N/A	N/A	N/A	N/A
9	1st triennial (2012-2014)	SCE	**Next-Generation Distribution Automation**	Grid Modernization and Optimization	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid Directed Awards Issued to the Following Vendor(s): Cleaveland Price Inc.; Doble Engineering Company; GE MDS LLC.; One Source Supply Solutions LLC.	2	G&W Electric Company; Par Electrical Contractors Inc.	G&W Electric Company; Par Electrical Contractors Inc.	
10	1st triennial (2012-2014)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration**	Customer Focused Products and Services	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	This was a "quasi-competitive" bid process conducted by the Energy Division (ED) of the CPUC	The ED opened the Phase 1 Pilot Submetering MDMA participation to all companies. Four companies applied: Electric Motor Werks, KnGrid, NRG and Ohmconnect. All four passed the initial pass/fail ED screening.	All four companies were approved by the ED to participate in the Phase 1 Submetering Pilot. Electric Motor Werks, KnGrid, NRG and Ohmconnect	There was no ranking provided by the ED. The four companies were free to choose which of the three IOU territories it wanted to participate in. Three companies, Electric Motor Werks, NRG and Ohmconnect selected to participate in SCE's territory. Note: PO process is not yet complete for Electric Motor Werks.	ED did not provide any scoring of the applicants.

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2	Investment Program Period	Program Administrator	Project Name	Project Type	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals	Applicable metrics
8	1st triennial (2012-2014)	SCE	**Dynamic Line Rating**	Grid Modernization and Optimization	N/A; Applicable to CEC only.		N/A; Applicable to CEC only.	3b. Maintain / Reduce capital costs 5b. Electric system power flow congestion reduction 6a. Increased power flow throughput 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
9	1st triennial (2012-2014)	SCE	**Next-Generation Distribution Automation**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	G&W Electric Company: California-based entity; Small Business Par Electrical Contractors Inc.: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 5i. Increase in the number of nodes in the power system at monitoring points 6a. Improve data accuracy for distribution substation planning process 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360); 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market). 9e. Technologies available for sale in the market place (when known).
10	1st triennial (2012-2014)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration**	Customer Focused Products and Services	N/A; Applicable to CEC only.	NRG: N/A Ohmconnect: California-based entity Electric Motor Werks: California-based entity	N/A; Applicable to CEC only.	6a. TOTAL number of SCE customer participants (Phase 1 & 2 each have 500 submeter limit) 6b. Number of SCE NEM customer participants (Phase 1 & 2 each have 100 submeter limit of 500 total) 6c. Submeter MDMA on-time delivery of customer submeter interval usage data 6d. Submeter MDMA accuracy of customer submeter interval usage data

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2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**2019 Update**	
8	1st triennial (2012-2014)	SCE	**Dynamic Line Rating**	Grid Modernization and Optimization	The final project report is complete, was submitted with the 2017 Annual Report, and is available on SCE's public EPIC web site.	
9	1st triennial (2012-2014)	SCE	**Next-Generation Distribution Automation**	Grid Modernization and Optimization	The final project report summary is complete, was submitted with the 2018 Annual Report, and is available on SCE's public EPIC web site.	
10	1st triennial (2012-2014)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration**	Customer Focused Products and Services	The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site.	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
2	Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
11	1st triennial (2012-2014)	SCE	**Distribution Planning Tool**	Energy Resources Integration	This project involves the creation, validation, and functional demonstration of an SCE distribution system model that will address the future system architecture that accommodates distributed generation (primarily solar photovoltaic), plug-in electric vehicles, energy storage, customer programs (demand response, energy efficiency), etc. The modeling software to be used allows for implementation of advanced controls (smart charging, advanced inverters, etc.). These controls will enable interaction of a residential energy module and a power flow module. It also enables the evaluation of various technologies from an end-use customer perspective as well as a utility perspective, allowing full evaluation from substation bank to customer. This capability does not exist today. The completed model will help SCE demonstrate, communicate and better respond to technical, customer and market challenges as the distribution system architecture evolves.	8/15/2012	No	Distribution	$ -	$ -	$ 850,911	$ 220,207	$ 1,071,118	N/A
12	1st triennial (2012-2014)	SCE	**Portable End-to-End Test System**	Grid Modernization and Optimization	End-to-end transmission circuit relay testing has become essential for operations and safety. SCE technicians currently test relay protection equipment during commissioning and routing testing. Existing tools provide a limited number of scenarios (disturbances) for testing, and focus on testing protection elements; not testing system protection. This project will demonstrate a robust portable end-to-end toolset (PETS) that addresses: 1) relay protection equipment, 2) communications, and 3) provides a pass/fail grade based on the results of automated testing using numerous simulated disturbances. PETS will employ portable Real-Time Digital Simulators (RTDS's) in substations at each end of the transmission line being tested. Tests will be documented using a reporting procedure used in the Power Systems Lab today, which will ensure that all test data is properly evaluated.	8/15/2012	No	Transmission	$ -	$ -	$ 33,167	$ 6,396	$ 39,563	N/A
13	1st triennial (2012-2014)	SCE	Superconducting Transformer (SCX) Demo	Grid Modernization and Optimization	SCE will support this $21M American Reinvestment and Recovery Act (ARRA) Superconducting Transformer (SCX) project by providing technical expertise and installing and operating the transformer at SCE's MacArthur substation. The SCX prime contractor is SuperPower Inc. (SPI), teamed with SPX Transformer Solutions (SPX) {formerly Waukesha Electric Systems}. SCE has provided two letters of commitment for SCX. The SCX project will develop a 28 MVA High Temperature Superconducting, Fault Current Limiting (HTS-FCL) transformer. The transformer is expected to be installed in 2015. SCE is supporting this project and is not an ARRA grant sub-recipient. SCE is being reimbursed for its effort by EPIC. SCE's participation in this project was previously approved under the now defunct California Energy Commission's PIER program.	8/15/2012	No	Distribution	$ -	$ -	$ 4,022	$ 6,219	$ 10,241	N/A

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2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**Leveraged Funds**	**Partners**	**Match Funding**	**Match Funding Split**	**Funding Mechanism**	**Intellectual Property**	**Identification of the method used to grant awards.**	**If competitively selected, provide the number of bidders passing the initial pass/fail screening for project**	**If competitively selected, provide the name of selected bidder.**	**If competitively selected, provide the rank of the selected bidder in the selection process.**	**If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.**
11	1st triennial (2012-2014)	SCE	**Distribution Planning Tool**	Energy Resources Integration	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Battelle Memorial Institute CYME International T&D Inc. INFOSYS Limited Nexant Inc Siemens Industry Siemens Industry, Inc.	N/A	N/A	N/A	N/A
12	1st triennial (2012-2014)	SCE	**Portable End-to-End Test System**	Grid Modernization and Optimization	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Doble Engineering Company; General Electric Company: RTDS Technologies Inc.; Schweitzer Engineering Labs Inc.	N/A	N/A	N/A	N/A
13	1st triennial (2012-2014)	SCE	Superconducting Transformer (SCX) Demo	Grid Modernization and Optimization	N/A	SuperPower Inc.; SPX Transformer Solutions	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	N/A	N/A	N/A	N/A	N/A

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2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.**	**Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?**	**How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals**	**Applicable metrics**
11	1st triennial (2012-2014)	SCE	**Distribution Planning Tool**	Energy Resources Integration	N/A; Applicable to CEC only.	Battelle Memorial Institute: N/A CYME International T&D Inc. - N/A INFOSYS Limited - Yes (CA entity) Nexant Inc - Yes (CA entity) Siemens Industry - Yes (CA entity) Siemens Industry, Inc. - Yes (CA entity)	N/A; Applicable to CEC only.	1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 5c. Forecast accuracy improvement 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360); 8c. Number of times reports are cited in scientific journals and trade publications for selected projects. 8d. Number of information sharing forums held. 8f. Technology transfer 9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market).
12	1st triennial (2012-2014)	SCE	**Portable End-to-End Test System**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	Doble Engineering Company: N/A General Electric Company: N/A RTDS Technologies Inc.: N/A Schweitzer Engineering Labs Inc: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 5a. Outage number, frequency and duration reductions 6a. Reduction in testing cost 6b. Number of terminals tested on a line (more than 2 terminals/substations) 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9e. Technologies available for sale in the market place (when known).
13	1st triennial (2012-2014)	SCE	Superconducting Transformer (SCX) Demo	Grid Modernization and Optimization	N/A; Applicable to CEC only.	N/A; Project is cancelled.	N/A; Applicable to CEC only.	N/A; Project is cancelled

	A	B	C	D	AD	AE
2	Investment Program Period	Program Administrator	Project Name	Project Type	2019 Update	
11	1st triennial (2012-2014)	SCE	**Distribution Planning Tool**	Energy Resources Integration	The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site.	
12	1st triennial (2012-2014)	SCE	**Portable End-to-End Test System**	Grid Modernization and Optimization	The final project report is complete, was submitted with the 2015 Annual Report, and is available on SCE's public EPIC web site.	
13	1st triennial (2012-2014)	SCE	Superconducting Transformer (SCX) Demo	Grid Modernization and Optimization	SCE formally cancelled this project in Q3 2014.	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**A brief description of the project**	**Date of the award**	**Was this project awarded in the immediately prior calendar year?**	**Assignment to Value Chain**	**Encumbered Funding Amount ($)**	**Committed Funding Amount ($)**	**Funds Expended to date: Contract/Grant Amount ($)**	**Funds Expended to date: In house expenditures ($)**	**Funds Expended to date: Total Spent to date ($)**	**Administrative and overhead costs incurred for each project**
14	1st triennial (2012-2014)	SCE	Wide-Area Reliability Management & Control	Energy Resources Integration	With the planned wind and solar portfolio of 33% penetration, a review of the integration strategy implemented in the SCE bulk system is needed. The basic premise for the integration strategy is that a failure in one area of the grid should not result in failures elsewhere. The approach is to minimize failures with well designed, maintained, operated, and coordinated power grids. New technologies can provide coordinated wide-area monitoring, protection, and control systems with pattern recognition and advance warning capabilities. This project will demonstrate new technologies to manage transmission system control devices to prevent cascading outages and maintain system integrity.	8/15/2012	No	Grid Operation/Market Design	$ -	$ 4,938	$ 622,816	$ 122,246	$ 745,062	N/A
15	1st triennial (2012-2014)	SCE	**Outage Management and Customer Voltage Data Analytics Demonstration**	Customer Focused Products and Services	Voltage data and customer energy usage data from the Smart Meter network can be collected and leveraged for a range of initiatives focused on achieving operational benefits for Transmission & Distribution. Before a full implementation of this new approach can be considered, a demonstration project will be conducted to understand how voltage and consumption data can be best collected, stored, and integrated with T&D applications to provide analytics and visualization capabilities. Further, Smart Meter outage and restoration event (time stamp) data can be leveraged to improve customer outage duration and frequency calculations. Various stakeholders in T&D have identified business needs to pursue more effective and efficient ways of calculating SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index), and MAIFI (Momentary Average Interruption Frequency Index) for internal and external reporting. Before a full implementation of this new approach can be considered, a demonstration project will be conducted to understand the feasibility and value of providing smart meter data inputs and enhanced methodology for calculating the Indexes. The demonstration will focus on a limited geography (SCE District or Region) to obtain the Smart Meter inputs to calculate the Indexes and compare that number with the current methodologies to identify any anomalies. A hybrid approach using the Smart Meter-based input data combined with a better comprehensive electric connectivity model obtained from GIS may provide a more efficient and effective way of calculating the Indexes. Additionally, an effort to evaluate the accuracy of the Transformer Load Mapping data will be carried out.	11/1/2012	No	Grid Operation/Market Design	$ -		$ 713,145	$ 305,552	$ 1,018,697	N/A

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2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**Leveraged Funds**	**Partners**	**Match Funding**	**Match Funding Split**	**Funding Mechanism**	**Intellectual Property**	**Identification of the method used to grant awards.**	**If competitively selected, provide the number of bidders passing the initial pass/fail screening for project**	**If competitively selected, provide the name of selected bidder.**	**If competitively selected, provide the rank of the selected bidder in the selection process.**	**If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.**
14	1st triennial (2012-2014)	SCE	Wide-Area Reliability Management & Control	Energy Resources Integration	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): V&R Energy Systems Research, Inc.; Siemens Industry, Inc	N/A	N/A	N/A	N/A
15	1st triennial (2012-2014)	SCE	**Outage Management and Customer Voltage Data Analytics Demonstration**	Customer Focused Products and Services	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Cyient, Inc.; Nexant Inc	N/A	N/A	N/A	N/A

	A	B	C	D	Z	AA	AB	AC
2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.**	**Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?**	**How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals**	**Applicable metrics**
14	1st triennial (2012-2014)	SCE	Wide-Area Reliability Management & Control	Energy Resources Integration	N/A; Applicable to CEC only.	V&R Energy Systems Research, Inc.: California-based entity Siemens Industry, Inc.: California-based entity	N/A; Applicable to CEC only.	6a. Enhanced contingency planning for minimizing cascading outages 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer
15	1st triennial (2012-2014)	SCE	**Outage Management and Customer Voltage Data Analytics Demonstration**	Customer Focused Products and Services	N/A; Applicable to CEC only.	Cyient, Inc.: N/A Nexant Inc: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 6a. Enhance Outage Reporting Accurary and SAIDI/SAIFI Calculation 8b. Number of reports and fact sheets published online 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports.

	A	B	C	D	AD	AE
2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**2019 Update**	
14	1st triennial (2012-2014)	SCE	Wide-Area Reliability Management & Control	Energy Resources Integration	The final project report is complete, is being submitted with the 2019 Annual Report, and will be available on SCE's public EPIC web site.	
15	1st triennial (2012-2014)	SCE	**Outage Management and Customer Voltage Data Analytics Demonstration**	Customer Focused Products and Services	The final project report is complete, was submitted with the 2015 Annual Report, and is available on SCE's public EPIC web site.	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
2	Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
16	1st triennial (2012-2014)	SCE	SA-3 Phase III Demonstration	Grid Modernization and Optimization	This project is intended to apply the findings from the Substation Automation Three (SA-3) Phase II (Irvine Smart Grid Demonstration) project to demonstrate real solutions to automation problems faced by SCE today. The project will demonstrate two standards-based automation solutions (sub projects) as follows: Subproject 1 (Bulk Electric System) will address issues unique to transmission substations including the integration of centrally managed critical cyber security (CCS) systems and NERC CIP compliance; Subproject 2 (Hybrid) will address the integration of SA-3 capabilities with SAS and SA-2 legacy systems. Furthermore, as part of the systems engineering the SA-3 technical team will demonstrate two automation tools as follows: Subproject 3 (Intelligent Alarming) will allow substation operators to pin-point root cause issues by analyzing the various scenarios and implement an intelligent alarming system that can identify the source of the problem and give operators only the relevant information needed to make informed decisions; and Subproject 4 (Real Time Digital Simulator (RTDS) Mobile Testing) will explore the benefits of an automated testing using a mobile RTDS unit, and propose test methodologies that can be implemented into the factory acceptance testing (FAT) and site acceptance testing (SAT) testing process.	8/15/2012	No	Transmission	$ 1,026,454	$ 657,790	$ 4,090,779	$ 826,841	$ 4,917,620	N/A
17	1st triennial (2012-2014)	SCE	**Enhanced Infrastructure Technology Evaluation**	Grid Modernization and Optimization	At the request of Distribution Apparatus Engineering (DAE) group's lead Civil Engineer, Advanced Technology (AT) will investigate, demonstrate, and come up with recommendations for enhanced infrastructure technologies. The project will focus on evaluating advanced: distribution sectional poles (hybrid, coatings, etc.), concealed communications on assets, vault monitoring systems (temperature, water, etc.), and vault ventilation systems. Funding is required to investigate the problem, engineering, demonstrate alternatives, and come up with recommendations. DAE sees the need for poles that can withstand fires and have a better life cycle cost, and provide installation efficiencies when compared to existing wood pole replacements. Due to increased city restrictions, there is a need for more concealed communications on our assets such as streetlights (e.g., on the ISGD project, the City of Irvine wouldn't allow us to install repeaters on streetlights due to aesthetics). DAE also sees the need for technologies that may minimize premature vault change-outs (avg. replacement cost is ~$250K). At present, DAE does not have the necessary real-time vault data to sufficiently address the increasing vault deterioration issue nor do we utilize a hardened ventilation system that would help this issue by removing the excess heat out of the vaults (blowers last ~ 2 years, need better bearings for blower motors, etc.).	12/17/2013	No	Distribution	$ -		$ 33,972	$ 45,147	$ 79,119	N/A
18	1st triennial (2012-2014)	SCE	**Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)**	Cross-Cutting/Foundational Strategies & Technologies	Viasat in partnership with SCE and Duke Energy has been awarded a DOE contract (DE-0E0000675) to deploy a Cyber-intrusion Auto-response and Policy Management System (CAPMS) to provide real-time analysis of root cause, extent and consequence of an ongoing cyber intrusion using proactive security measures. CAPMS will be demonstrated in the SCE Advanced Technology labs at Westminster, CA. The DOE contract value is $6M with SCE & Duke Energy offering a cost share of $1.6M and $1.2M respectively.	7/16/2014	Yes	Grid Operation/Market Design	$ -		$ 1,703,952	$ 105,371	$ 1,809,323	N/A

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2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**Leveraged Funds**	**Partners**	**Match Funding**	**Match Funding Split**	**Funding Mechanism**	**Intellectual Property**	**Identification of the method used to grant awards.**	**If competitively selected, provide the number of bidders passing the initial pass/fail screening for project**	**If competitively selected, provide the name of selected bidder.**	**If competitively selected, provide the rank of the selected bidder in the selection process.**	**If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.**
16	1st triennial (2012-2014)	SCE	SA-3 Phase III Demonstration	Grid Modernization and Optimization	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid ((Request for Proposal) to the Following Vendor(s): 1- .... (Direct award) to the Following Vendor(s): 2-	N/A	N/A	N/A	N/A
17	1st triennial (2012-2014)	SCE	**Enhanced Infrastructure Technology Evaluation**	Grid Modernization and Optimization	N/A	N/A	N/A	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): American Restore, Inc.; Rivcomm, Inc.; California Turbo Inc	N/A	N/A	N/A	N/A
18	1st triennial (2012-2014)	SCE	**Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)**	Cross-Cutting/Foundational Strategies & Technologies	DOE & Duke Energy Contributions: $4,486,430	Viasat; Duke Energy	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): @ Business Inc; Magnetic Instrumentation Inc; Saker Systems, LLC; World Wide Technology Inc; Zones, Inc.; Accuvant Inc; Electric Power Group, LLC; Schweitzer Engineering Labs Inc	N/A	N/A	N/A	N/A

	A	B	C	D	Z	AA	AB	AC
2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.**	**Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?**	**How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals**	**Applicable metrics**
16	1st triennial (2012-2014)	SCE	SA-3 Phase III Demonstration	Grid Modernization and Optimization	N/A; Applicable to CEC only.		N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 5a. Outage number, frequency and duration reductions 5i. Increase in the number of nodes in the power system at monitoring points 6a. Increased cybersecurity 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market). 9e. Technologies available for sale in the market place (when known).
17	1st triennial (2012-2014)	SCE	**Enhanced Infrastructure Technology Evaluation**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	American Restore, Inc.: California-based entity Rivcomm, Inc.: California-based entity; Small Business California Turbo Inc: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 4g. Wildlife fatality reductions (electrocutions, collisions) 5a. Outage number, frequency and duration reductions 6a. Operating performance of underground vault monitoring equipment 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports.
18	1st triennial (2012-2014)	SCE	**Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)**	Cross-Cutting/Foundational Strategies & Technologies	N/A; Applicable to CEC only.	@ Business Inc: DBE Magnetic Instrumentation Inc: N/A Saker Systems, LLC: California-base entity; Small Business; DBE World Wide Technology Inc: DBE Zones, Inc.: DBE Accuvant Inc: California-based entity Electric Power Group, LLC: California-based entity Schweitzer Engineering Labs Inc: California-based entity	N/A; Applicable to CEC only.	5a. Outage number, frequency and duration reductions 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 10a. Description or documentation of funding or contributions committed by others 10c. Dollar value of funding or contributions committed by others.

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2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**2019 Update**	
16	1st triennial (2012-2014)	SCE	SA-3 Phase III Demonstration	Grid Modernization and Optimization	2019 Accomplishments: In 2019 the SA-3 Phase 3 Project focused primarily on defining and integrating cybersecurity and compliance requirements for the project. Significant efforts were made to perform cybersecurity assessments and define cybersecurity requirements and solutions for the Substation Management System (SMS), the Protection Automation Controller Annunciator, Substation Network, and connectivity to the historian from the Human Machine Interface. A large focus was placed on the SMS cybersecurity requirements pertaining to device password management, authorization, authentication, and encryption. The project worked closely with the vendor to implement configuration changes and its expecting to begin testing of this cybersecurity requirement in Q1 2020. As the cybersecurity and compliance efforts were underway the team began functional testing of the SMS system, and worked closely with the manufacturer to resolve the issues encountered, as well as documenting functional gaps. The team defined the IEC 61850 configuration file options to be utilized between the HMI and the Data historian and began initial testing. Complete HMI to Data Historian testing is expected to be completed in 2020.	
17	1st triennial (2012-2014)	SCE	**Enhanced Infrastructure Technology Evaluation**	Grid Modernization and Optimization	The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site.	
18	1st triennial (2012-2014)	SCE	**Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)**	Cross-Cutting/Foundational Strategies & Technologies	The final project report is complete, was submitted with the 2015 Annual Report, and is available on SCE's public EPIC web site.	

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2	Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
19	2nd triennial (2015-2017)	SCE	**Integration of Big Data for Advanced Automated Customer Load Management**	Customer Focused Products and Services	This proposed project will demonstrate the use of an IEEE 2030.5 compliant Distributed Energy Resources Management System (DERMS) in order to: 1.Demonstrate the IEEE 2030.5 Common Smart Inverter Profile (CSIP) use cases (grouping, monitoring, controls, and registration) being developed by the IOUs, with results being used to inform development of the profile 2.Evaluate the use of the IEEE 2030.5 Distributed Energy Resources (DER) Function Set for effectiveness and completeness, with results being used to inform future revisions of the standard 3.Demonstrate a standardized interface between SCE's back office systems (e.g., the utility integration bus or UIB) and the DERMS.	11/17/2014	Yes	Demand-Side Management	$ -	$ -	$ 1,179,099	$ 20,202	$ 1,199,301	$ 5,113
20	2nd triennial (2015-2017)	SCE	**Advanced Grid Capabilities Using Smart Meter Data**	Grid Modernization and Optimization	This project will examine the possibility of establishing the Phasing information for distribution circuits, by examining the voltage signature at the meter and transformer level, and by leveraging the connectivity model of the circuits. This project will also examine the possibility of establishing transformer to meter connectivity based on the voltage signature at the meter and at the transformer level.	11/17/2014	Yes	Distribution	$ -	$ -	$ 10,775	$ 196,313	$ 207,088	$ 6,871

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2	Investment Program Period	Program Administrator	Project Name	Project Type	Leveraged Funds	Partners	Match Funding	Match Funding Split	Funding Mechanism	Intellectual Property	Identification of the method used to grant awards.	If competitively selected, provide the number of bidders passing the initial pass/fail screening for project	If competitively selected, provide the name of selected bidder.	If competitively selected, provide the rank of the selected bidder in the selection process.	If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.
19	2nd triennial (2015-2017)	SCE	**Integration of Big Data for Advanced Automated Customer Load Management**	Customer Focused Products and Services	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive	1	Kitu, Inc	TBD	TBD
20	2nd triennial (2015-2017)	SCE	**Advanced Grid Capabilities Using Smart Meter Data**	Grid Modernization and Optimization	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	N/A - This technology is very new	There are almost no vendors offering technologies in this area

	A	B	C	D	Z	AA	AB	AC
2	Investment Program Period	Program Administrator	Project Name	Project Type	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals	Applicable metrics
19	2nd triennial (2015-2017)	SCE	**Integration of Big Data for Advanced Automated Customer Load Management**	Customer Focused Products and Services	N/A; Applicable to CEC only.	Small Business	N/A; Applicable to CEC only.	Metrics plan TBD
20	2nd triennial (2015-2017)	SCE	**Advanced Grid Capabilities Using Smart Meter Data**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 8d. Number of information sharing forums held 8f. Technology transfer

	A	B	C	D	AD	AE
2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**2019 Update**	
19	2nd triennial (2015-2017)	SCE	**Integration of Big Data for Advanced Automated Customer Load Management**	Customer Focused Products and Services	This project is closed and the final report was submitted with the 2018 annual report	
20	2nd triennial (2015-2017)	SCE	**Advanced Grid Capabilities Using Smart Meter Data**	Grid Modernization and Optimization	The final project report is complete, was submitted with the 2017 Annual Report, and is available on SCE's public EPIC web site.	

	Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
21	2nd triennial (2015-2017)	SCE	**Proactive Storm Impact Analysis Demonstration**	Grid Modernization and Optimization	This project will demonstrate proactive storm analysis techniques prior to its arrival and estimate its potential impact on utility operations. In this project, we will investigate some technologies that can model a developing storm and its potential movement through the utility service territory based on weather projections. This information and model will then be integrated with the Geographic Information System (GIS) electrical connectivity model, Distribution Management System (DMS), and Outage Management System (OMS) functionalities, along with historical storm data to predict the potential impact on the service to customers. In addition, this project will demonstrate the integration of near real time meter voltage data with the GIS network to develop a simulated circuit model that can be effectively utilized for storm management and field crew deployment.	11/17/2014	Yes	Distribution	$ -	$ -	$ 1,078,310	$ 129,815	$ 1,208,125	$ 12,464
22	2nd triennial (2015-2017)	SCE	**DC Fast Charging Demonstration**	Customer Focused Products and Services	The goal of this project is to demonstrate public DC fast charging stations at SCE facilities near freeways in optimal locations to benefit electric vehicle miles traveled (eVMT) by plug-in electric vehicles (PEVs) while implementing smart grid equipment and techniques to minimize system impact. The Transportation Electrification (TE) Organization is actively pursuing several strategic objectives, including optimizing TE fueling from the grid to improve asset utilization. Deploying a limited number of fast charging stations at selected SCE facilities that are already equipped to deliver power at this level (without additional infrastructure upgrade) will support this objective. The project will leverage SCE's vast service territory and its facilities to help PEV reach destinations that would otherwise be out-of-range	11/16/2015	No	Demand-Side Management	$ -	$ -	$ 11,637	$ 10,308	$ 21,945	$ 1,172
23	2nd triennial (2015-2017)	SCE	**Next-Generation Distribution Equipment & Automation - Phase 2**	Grid Modernization and Optimization	This project will leverage lessons learned from the Next Generation Distribution Automation – Phase 1 project performed in the first EPIC triennial investment plan period. This project will focus on integrating advanced control systems, modern wireless communication systems, and the latest breakthroughs in distribution equipment and sensing technology to develop a complete system design that would be a standard for distribution automation and advanced distribution equipment	11/16/2015	Yes	Distribution	$ 973,091	$ 2,517,993	$ 4,461,022	$ 781,202	$ 5,242,224	$ 127,669
24	2nd triennial (2015-2017)	SCE	**System Intelligence and Situational Awareness Capabilities**	Grid Modernization and Optimization	This project will demonstrate system intelligence and situation awareness capabilities such as high impedance fault detection, intelligent alarming, predictive maintenance, and automated testing. This will be accomplished by integrating intelligent algorithms and advanced applications with the latest substation automation technologies, next generation control systems, latest breakthrough in substation equipment, sensing technology, and communications assisted protection schemes, This system will leverage the IEC 61850 Automation Standard and will include cost saving technology such as process bus, peer to peer communications, and automated engineering and testing technology. This project will also inform complementary efforts at SCE aimed at meeting security and NERC CIP compliance requirements	11/16/2015	No	Distribution	$ 336,915	$ 662,298	$ 2,013,587	$ 189,416	$ 2,203,003	$ 4,774

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2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**Leveraged Funds**	**Partners**	**Match Funding**	**Match Funding Split**	**Funding Mechanism**	**Intellectual Property**	**Identification of the method used to grant awards.**	**If competitively selected, provide the number of bidders passing the initial pass/fail screening for project**	**If competitively selected, provide the name of selected bidder.**	**If competitively selected, provide the rank of the selected bidder in the selection process.**	**If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.**
21	2nd triennial (2015-2017)	SCE	**Proactive Storm Impact Analysis Demonstration**	Grid Modernization and Optimization	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive	9	IBM, First Quartile Consulting	TBD	TBD
22	2nd triennial (2015-2017)	SCE	**DC Fast Charging Demonstration**	Customer Focused Products and Services	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD
23	2nd triennial (2015-2017)	SCE	**Next-Generation Distribution Equipment & Automation - Phase 2**	Grid Modernization and Optimization	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid Directed Awards Issued to the Following Vendor(s): Athena Power, Inc.; G&W Electric Company; Southwest Research Institute	4	Cleaveland Price Inc.; Schneider Electric; Sentient Energy, Inc.; Wesco Distribution Inc.	Cleaveland Price Inc.; Schneider Electric; Sentient Energy, Inc.; Wesco Distribution Inc.	Multiple prototypes were required for testing purposes
24	2nd triennial (2015-2017)	SCE	**System Intelligence and Situational Awareness Capabilities**	Grid Modernization and Optimization	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid Directed Awards Issued to the Following Vendor(s): GENERAL NETWORKS, TESCO AUTOMATION LTD, MORRIS & WILLNER PARTNERS,	N/A	N/A	N/A	N/A

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2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.**	**Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?**	**How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals**	**Applicable metrics**
21	2nd triennial (2015-2017)	SCE	**Proactive Storm Impact Analysis Demonstration**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	First Quartile: Small Business	N/A; Applicable to CEC only.	2a. Hours worked in California and money spent in California for each project 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 8f. Technology transfer 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
22	2nd triennial (2015-2017)	SCE	**DC Fast Charging Demonstration**	Customer Focused Products and Services	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	3a. Maintain/Reduce operations and maintenance costs 5b. Electric system power flow congestion reduction 5h. Reduction in system harmonics 8d. Number of information sharing forums held 8e. Stakeholders attendance at workshops 8f. Technology transfer
23	2nd triennial (2015-2017)	SCE	**Next-Generation Distribution Equipment & Automation - Phase 2**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	Sentient Energy, Inc.: California-based entity Wesco Distribution Inc.: California-based entity; Business owned by women, minorities, or disabled veterans	N/A; Applicable to CEC only.	3a. Maintain/reduce operations and maintenance costs 3e. Non-energy economic benefits 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communication concerning grid operations and status, and distribution automation (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
24	2nd triennial (2015-2017)	SCE	**System Intelligence and Situational Awareness Capabilities**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	GENERAL NETWORKS: California-based entity MORRIS & WILLNER PARTNERS: California-based entity	N/A; Applicable to CEC only.	2a. Hours worked in California and money spent in California for each project 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5a. Outage number, frequency and duration reductions 5e. Utility worker safety improvement and hazard exposure reduction 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 8e. Stakeholders attendance at workshops 8f. Technology transfer

	A	B	C	D	AD	AE
2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**2019 Update**	
21	2nd triennial (2015-2017)	SCE	**Proactive Storm Impact Analysis Demonstration**	Grid Modernization and Optimization	The final project report is complete, was submitted with the 2018 Annual Report, and is available on SCE's public EPIC web site.	
22	2nd triennial (2015-2017)	SCE	**DC Fast Charging Demonstration**	Customer Focused Products and Services	The final project report is complete, was submitted with the 2018 Annual Report, and is available on SCE's public EPIC web site.	
23	2nd triennial (2015-2017)	SCE	**Next-Generation Distribution Equipment & Automation - Phase 2**	Grid Modernization and Optimization	2019 Accomplishments: **Remote Integrated Switch (RIS):** The RIS team supported the successful deployment of the 2.5 Extended scheme at the Johanna Substation. In addition, the team completed validation testing of the 3.5 Extended scheme concept. SCE partnered with an Augmented Reality (AR) vendor and created AR content to help overcome Organizational Change Management (OCM) challenges and provide best practices to electrical technicians. Lastly, the project team designed, negotiated and executed a new program phase to address lessons learned and stakeholder concerns related to a large deployment and system scalability. **High Impedance Fault Detection** In 2019 the system hardware upgrade was completed. In March, SCE completed the initial testing of the upgraded hardware. The results of the testing were promising in that SCE was able to detect wired down scenarios that were unable to be detected in previous tests. A second round of testing was scheduled to validate March's results but were delayed due to unforeseen circumstances. These validation tests are projected to take place 1st quarter of 2020. **Real-time Equipment Health Diagnostic** Completed evaluation of two vendors and one was selected to move forward in 2019 contingent on their ability to produce a Field ready prototype for demonstrations on SCE circuitry. The vendor was unable to produce a Field ready prototype so no further work was done regarding this project in 2019. **Long Beach Secondary Network Situation Awareness** Field evaluation results indicated the Long Beach NMS tool was deficient in terms of State Estimation on the secondary side (50% to 300% error). SCE determined that unless State Estimation values are within 10% of measured values, SCE will not consider the NMS tool to be suitable for field deployment. Oracle was offer an extension to 10/15/2019 to improve its algorithm but was unable to make much progress by 10/15/2019. Oracle was then given a deadline of 12/31/2019 to deliver better results but was unable to do so. The NMS project had, therefore, been effectively canceled.	
24	2nd triennial (2015-2017)	SCE	**System Intelligence and Situational Awareness Capabilities**	Grid Modernization and Optimization	2019 Update Substation Test Tools The Substation Demonstrations team worked with Triangle MicroWorks to advance SCE specific test scripts for use with their IEC 61850 substation simulation tool, known as Distributed Test Manager (DTM). Following a series of meetings where we provided feedback on pre-released versions of DTM, the major online release of DTM version 1.4 was made available in March 2019. When DTM v1.4 was made available online, the Substation Demonstrations team and Control & Meter Asset Engineering team tested the new version with various substation configurations. During this process, some issues were identified with the tool's workspace generation. We provided additional documentation and met with the vendor to troubleshoot throughout the remainder of the year. The Substation Demonstrations team met with other end users, such as the Substation Test School operators to demonstrate how DTM can be used in conjunction with the HMI to provide more in-depth and interactive training for HMI operation and functions. Process Bus The Mayberry optical CT/process bus pilot was successfully commissioned in June 2019. Various stakeholders were involved in the process such as construction, technical support & strategy, protection and automation engineering, and substation engineering. This demonstrated SCE's first field installation of IEC-61850 technology. The next phase of process bus includes testing a full substation in our laboratory environment. Work has already commenced and a full design for a laboratory demonstration was completed in 2019. The design included input from various stakeholders such as protection and automation engineering and encouraged future thinking design considerations.	

Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
2nd triennial (2015-2017)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration - Phase 2**	Customer Focused Products and Services	This project expands on the submetering project from the first EPIC triennial investment plan cycle to demonstrate plug-in electric vehicle (PEV) submetering at multi-dwelling and commercial facilities. Specifically, the project will leverage 3rd party metering to conduct subtractive billing for various sites including those with multiple customers of record	11/17/2014	Yes	Demand-Side Management	$ -	$ -	$ 1,079,552	$ 132,277	$ 1,211,829	$ 8,036
2nd triennial (2015-2017)	SCE	Bulk System Restoration Under High Renewables Penetration	Renewables/DER Resource Integration	The Bulk System Restoration under High Renewable Penetration Project will evaluate system restoration plans following a blackout event under high penetration of wind and solar generation resources. Typically the entire restoration plan consists of three main stages; Black Start, System Stabilization, and load pick-up. The Project will be divided into two phases: * Phase I of the project will address the feasibility of new approaches to system restoration by reviewing the existing system restoration plans and it's suitability for higher penetration of renewable generation. It will include a suitable RTDS Bulk Power system to be used in the first stage of system restoration, black start and it will also include the modeling of wind and solar renewable resources. * Phase II of the project will focus on on-line evaluation of restoration plans using scenarios created using (RTDS) with hardware in the loop such as generation, transformer and transmission line protective relays. The RTDS is a well-known tool to assess and evaluate performance of protection and control equipment. This project intends to utilize the RTDS capabilities to evaluate and demonstrate system restoration strategies with variable renewable resources focusing on system stabilization and cold load pick-up. Furthermore alternate restoration scenarios will be investigated. After the restoration process is evaluated, tested, and demonstrated in the RTDS Lab environment, a recommendation will be provided to system operations and transmission planning for their inputs for further developing this approach into an actual operational tool.	11/17/2014	Yes	Transmission	$ -		$ 8,326	$ 33,867	$ 42,193	$ 4,355
2nd triennial (2015-2017)	SCE	Series Compensation for Load Flow Control (Power Flow Control with TCSC)	Renewables/DER Resource Integration	The intent of this project is to demonstrate and deploy the use of Thyristor Controlled Series Capacitors (TCSC) for load flow control on series compensated transmission lines. On SCE's 500 kV system in particular, several long transmission lines are series compensated using fixed capacitor segments that do not support active control of power flow. The existing fixed series capacitors use solid state devices as a protection method and are called Thyristor Protected Series Capacitors (TPSC)	11/16/2015	No	Transmission	$ -		$ -	$ 5,920	$ 5,920	$ 2,548

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2	Investment Program Period	Program Administrator	Project Name	Project Type	Leveraged Funds	Partners	Match Funding	Match Funding Split	Funding Mechanism	Intellectual Property	Identification of the method used to grant awards.	If competitively selected, provide the number of bidders passing the initial pass/fail screening for project	If competitively selected, provide the name of selected bidder.	If competitively selected, provide the rank of the selected bidder in the selection process.	If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.
25	2nd triennial (2015-2017)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration - Phase 2**	Customer Focused Products and Services	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD
26	2nd triennial (2015-2017)	SCE	Bulk System Restoration Under High Renewables Penetration	Renewables/DER Resource Integration	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Non-Competitive Nayak Corporation Inc	NA	NA	NA	NA
27	2nd triennial (2015-2017)	SCE	Series Compensation for Load Flow Control (Power Flow Control with TCSC)	Renewables/DER Resource Integration	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD

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2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.**	**Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?**	**How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals**	**Applicable metrics**
25	2nd triennial (2015-2017)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration - Phase 2**	Customer Focused Products and Services	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1h. Customer bill savings (dollars saved) 3e. Non-energy economic benefits 4a. GHG emissions reductions (MMTCO2e) 6a. The 3rd Party Evaluator, Nexant, in collaboration with the Energy Division and IOUs, will develop a set of metrics for Phase 2 to be included in the final report. 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 7j. Provide consumers with timely information and control options (PU Code § 8360): 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8e. Stakeholders attendance at workshops 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
26	2nd triennial (2015-2017)	SCE	Bulk System Restoration Under High Renewables Penetration	Renewables/DER Resource Integration	N/A; Applicable to CEC only.	Nayak Corporation - NA	N/A; Applicable to CEC only.	Metrics plan TBD
27	2nd triennial (2015-2017)	SCE	Series Compensation for Load Flow Control (Power Flow Control with TCSC)	Renewables/DER Resource Integration	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD

	A	B	C	D	AD	AE
2	Investment Program Period	Program Administrator	Project Name	Project Type	2019 Update	
25	2nd triennial (2015-2017)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration - Phase 2**	Customer Focused Products and Services	The final project report is complete, is being submitted with the 2019 Annual Report, and will be available on SCE's public EPIC web site.	
26	2nd triennial (2015-2017)	SCE	Bulk System Restoration Under High Renewables Penetration	Renewables/DER Resource Integration	In Dec. 2016, this project was cancelled by SCE Senior Leadership as a result of internal organizational change that focused the organization on Distribution System strategic objectives. This was reported in the 2016 EPIC Annual Report.	
27	2nd triennial (2015-2017)	SCE	Series Compensation for Load Flow Control (Power Flow Control with TCSC)	Renewables/DER Resource Integration	In 2016, it was determined that the deliverables for this project could easily be done via another project that was already in flight. So a determination was made to cancel this project. This was reported in the 2016 Annual Report.	

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2	Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
28	2nd triennial (2015-2017)	SCE	**Versatile Plug-in Auxiliary Power System (VAPS)**	Grid Modernization and Optimization	This project demonstrates the electrification of transportation and vocational loads that previously used internal combustion engines powered by petroleum fuels in the SCE fleet. The VAPS system uses automotive grade lithium ion battery technology (Chevrolet Volt and Ford Focus EV) which is also used in notable stationary energy storage projects (Tehachapi 32 MWh Storage)	11/17/2014	Yes	Distribution	$ -	$ -	$ 1,061,821	$ 85,477	$ 1,147,298	$ 2,897
29	2nd triennial (2015-2017)	SCE	**Dynamic Power Conditioner**	Grid Modernization and Optimization	This project will demonstrate the use of the latest advances in power electronics and energy storage devices and controls to provide dynamic phase balancing as well as providing voltage control, harmonics cancellation, sag mitigation, and power factor control while providing steady state operations such as injection and absorption of real and reactive power under scheduled duty cycles or external triggers. This project aims to mitigate the cause of high neutral currents and provide several power quality benefits through the use of actively controlled real and reactive power injection and absorption	11/17/2014	Yes	Distribution	$ 257,556	$ -	$ 804,822	$ 24,321	$ 829,143	$ 7,308
30	2nd triennial (2015-2017)	SCE	Optimized Control of Multiple Storage Systems	Renewables/DER Resource Integration	This project aims to demonstrate the ability of multiple energy storage controllers to integrate with SCE's Distribution Management System (DMS) and other decision making engines to realize optimum dispatch of real and reactive power based on grid needs	11/17/2014	Yes	Distribution	$ -		$ 138,289	$ 2,193	$ 140,482	$ -

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2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**Leveraged Funds**	**Partners**	**Match Funding**	**Match Funding Split**	**Funding Mechanism**	**Intellectual Property**	**Identification of the method used to grant awards.**	**If competitively selected, provide the number of bidders passing the initial pass/fail screening for project**	**If competitively selected, provide the name of selected bidder.**	**If competitively selected, provide the rank of the selected bidder in the selection process.**	**If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.**
28	2nd triennial (2015-2017)	SCE	**Versatile Plug-in Auxiliary Power System (VAPS)**	Grid Modernization and Optimization	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid Directed Awards Issued to the Following Vendor(s): FleetCarma	1	Altec Industries Inc.	1	N/A
29	2nd triennial (2015-2017)	SCE	**Dynamic Power Conditioner**	Grid Modernization and Optimization	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD
30	2nd triennial (2015-2017)	SCE	Optimized Control of Multiple Storage Systems	Renewables/DER Resource Integration	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD

	A	B	C	D	Z	AA	AB	AC
2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.**	**Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?**	**How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals**	**Applicable metrics**
28	2nd triennial (2015-2017)	SCE	**Versatile Plug-in Auxiliary Power System (VAPS)**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	No	N/A; Applicable to CEC only.	3a. Maintain/Reduce operations and maintenance costs 3e. Non-energy economic benefits 4a. GHG emissions reductions (MMTCO2e) 4b. Criteria air pollution emission reductions 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 8f. Technology transfer
29	2nd triennial (2015-2017)	SCE	**Dynamic Power Conditioner**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD
30	2nd triennial (2015-2017)	SCE	Optimized Control of Multiple Storage Systems	Renewables/DER Resource Integration	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD

	A	B	C	D	AD	AE
2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**2019 Update**	
28	2nd triennial (2015-2017)	SCE	**Versatile Plug-in Auxiliary Power System (VAPS)**	Grid Modernization and Optimization	**The final project report is complete, is being submitted with the 2019 Annual Report, and will be available on SCE's public EPIC web site.**	1
29	2nd triennial (2015-2017)	SCE	**Dynamic Power Conditioner**	Grid Modernization and Optimization	2019 Accomplishments: the DER Demonstrations Group continued to collaborate with Siemens Industry/Fluence to revise the inverter specifications to ensure that the system did not exceed the limits outlined in the interconnection application. The changes requested were to change the Energy Storage System apparent power rating change from 300 kVA to 250 kVA and modifying the winding ratio of the transformer. Once this request was made, Siemens/Fluence informed SCE that the container manufacturer would take longer to perform necessary modifications to accommodate EPC Power inverter, pushing installation from early April 2019 to the end of the 3rd Quarter of 2019. In the 4th Quarter of 2019, the project completed the installation of the system at the Pomona Lab Facility. The system was also commissioned in late December but needs to complete the final acceptance criteria before becoming operational. Once the system is operational, this project will demonstrate and evaluate the maturity of inverter technology that implements dynamic load balancing functionality. It also plans to verify that the DPC is capable of absorbing and/or injecting active power to individual phases to achieve balancing at all 3-phases. Finally, the project will evaluate the potential for this new inverter architecture to reduce the energy /footprint requirement of a deployed Ener+AE24gy Storage system.	
30	2nd triennial (2015-2017)	SCE	Optimized Control of Multiple Storage Systems	Renewables/DER Resource Integration	In 2017, the goals of this project were found to overlap significantly with those of the EPIC II Regional Grid Optimization Demo Phase 2 project (otherwise known as Integrated Grid Project phase 2). This project was then cancelled and the proposed benefits will be realized through the Regional Grid Optimization Demo Phase 2 project.	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
2	Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
31	2nd triennial (2015-2017)	SCE	**Integrated Grid Project II (filed as Regional Grid Optimization Demo)**	Cross-Cutting/Foundational Strategies & Technologies	The project will deploy, field test and measure innovative technologies that emerge from the design phase of the Integrated Grid Project (IGP) that address the impacts of DER (Distributed Energy Resources) owned by both 3rd parties and the utility. The objectives are to demonstrate the next generation grid infrastructure that manages, operates, and optimizes the distributed energy resources on SCE's system. The results will help determine the controls and protocols needed to manage DER, how to optimally manage an integrated distribution system to provide safe, reliable, affordable service and also how to validate locational value of DERs and understand impacts to future utility investments.	4/21/2016	No	Grid Operation/Market Design	$ 1,765,137	$ 2,378,225	$ 14,319,722	$ 834,712	$ 15,154,434	$ -

	A	B	C	D	O	P	Q	R	S	T	U	V	W	X	Y
2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**Leveraged Funds**	**Partners**	**Match Funding**	**Match Funding Split**	**Funding Mechanism**	**Intellectual Property**	**Identification of the method used to grant awards.**	**If competitively selected, provide the number of bidders passing the initial pass/fail screening for project**	**If competitively selected, provide the name of selected bidder.**	**If competitively selected, provide the rank of the selected bidder in the selection process.**	**If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.**
31	2nd triennial (2015-2017)	SCE	**Integrated Grid Project II (filed as Regional Grid Optimization Demo)**	Cross-Cutting/Foundational Strategies & Technologies	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid (Request for Proposals): Enbala Power Networks; Integral Analytics, LLC; Directed Awards Issued to the Following Vendor(s): DigSilent Americas LLC: Morris & Willner Partners; GE Management Services, LLC; World Wide Technology, Inc; Zones, Inc	9	Integral Analytics Enbala	1st 2nd	Does not apply; Highest scoring bidders were selected for award.

	A	B	C	D	Z	AA	AB	AC
2	Investment Program Period	Program Administrator	Project Name	Project Type	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals	Applicable metrics
31	2nd triennial (2015-2017)	SCE	**Integrated Grid Project II (filed as Regional Grid Optimization Demo)**	Cross-Cutting/Foundational Strategies & Technologies	N/A; Applicable to CEC only.	Morris & Willner Partners: Business owned my women, minorities or disabled veterans. World Wide Technology, Inc: Business owned my women, minorities or disabled veterans. Zones, Inc: Business owned my women, minorities or disabled veterans.	N/A; Applicable to CEC only.	1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 1h. Customer bill savings (dollars saved) 1i. Nameplate capacity (MW) of grid-connected energy storage 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5a. Outage number, frequency and duration reductions 5b. Electric system power flow congestion reduction 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360); 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360); 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations

	A	B	C	D	AD	AE
2	**Investment Program Period**	**Program Administrator**	**Project Name**	**Project Type**	**2019 Update**	
31	2nd triennial (2015-2017)	SCE	**Integrated Grid Project II (filed as Regional Grid Optimization Demo)**	Cross-Cutting/Foundational Strategies & Technologies	2019 Accomplishments: 1) IGP (Integrated Grid Project) Controllers 2019 Overview: The project developed and tested a new control system that monitored and operated multiple DERs under various conditions a) Completed QAS Environment integration testing (March 2019), included testing with the following: i) PCCs (Programmable Capacitor Controllers) ii) FAN (Field Area Network) radios iii) DESI-2 Battery b) Completed QAS Environment Formal Test Cases (April 2019) c) Completed QAS Environment Test Report (June 2019) d) Completed Demo D Close Out Report to CPUC (July 2019) 2) APS (Adaptive Protection System) 2019 Overview: Executed a pilot program to demonstrate the feasibility of adjusting the settings of protective devices. Note – The pilot program was conducted in 2018. The final reporting for this program was conducted in early 2019. a) Completed Final Project Report (January 2019) b) Final Project Report utilized by other programs, including Grid Modernization (on-going) 3) EPRI (Electrical Power Research Institute) 2019 Overview: SCE's project scope was to support EPRI with the testing of new technologies related to energy storage that connects to the utility transmission system, distribution system, and customer premises. a) Completed Laboratory Set Up, Test Plans, and Procedures (August 2019) b) Completed Laboratory Testing of Smart Solar PV Inverter, including the following: (October 2019) i) Undervoltage Support ii) Overvoltage Support c) Final Project Report (ECD: December 2019)	

Appendix B

Wide Area Reliability Management & Control Final Project Report

Wide Area Management and Control
Final Project Report

Developed by

SCE Transmission & Distribution, Grid Technology and Modernization

December 2019

Southern California Edison
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Acknowledgments

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Nagy Abed,	Project Engineer
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Aaron Renfro,	EPIC Administrator

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List of Acronyms

AGC	Automatic Generator Control
AHJ	Authority Having Jurisdiction
amp	Ampere
RAS	Remedial Action Schemes
BES	Bulk Energy System
BESS	Battery Energy Storage System
CAISO	California Independent System Operator
CEC	California Energy Commission
EMS	Energy Management System
CT	Current Transducer
CPUC	California Public Utilities Commission
HV	High voltage (side)
FACTS	Flexible AC Transmission Systems
FACRI	Fast AC Reactive Insertion
FC	Fixed Capacitor
FERC	Federal Energy Regulatory Commission
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
OSM	Oscillatory Stability Monitor
ERSTF	Essential Reliability Services Task Force
VT	Voltage Transducer
SCADA	Supervisory Control and Data Acquisition
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute

ESS	Energy Storage Systems
EMTP	Electromagnetic Transients Program
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GE	General Electric
GRC	General Rate Case
GW	Gigawatt
HTTPS	Hypertext Transfer Protocol Secure
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IRG	Inverter-based Renewable Generation Resources or Inverter-based Renewable Generators
IT	Informational Technology
kV	Kilovolt
kVAR	Kilovolt Ampere Reactive
kW	Kilowatt
kWh	Kilowatt-hour
LL	Line to Line
P	Active Power
POD	Power Oscillation Damper
Q	Reactive Power
LV	Low Voltage
ms	Millisecond
MSC	Mechanically Switched Capacitor
MVA	Megavolt-Ampere
MVAR	Megavolt Ampere Reactive
MVP	Minimum Viable Product

MW	Megawatt
MWh	Megawatt-hour
WECC	Western Electricity Coordinating Council
NERC	North American Reliability Corporation
NGR	Non-generating Resource
NREL	National Renewable Energy Laboratory
PCC	Point of Common Coupling
PFR	Primary Frequency Response
PG&E	Pacific Gas & Electric Company
PMU	Phasor Measurement Unit
POI	Point of Interconnection
PRC	Protection and Control
PSCAD	Power Systems Computer Aided Design Software
PSLF	Positive Sequence Load Flow and Dynamic Simulations
PSS/E	Siemens PTI Positive Sequence Load Flow and Dynamic Simulation
RFI	Request for Information
RFP	Request for Proposal
ROCOF	Rate of Change of Frequency
RTU	Remote Terminal Unit
RSCAD	Power system simulation software, a graphical user interface for RTDS
SCS	Short-circuit Strength
SE	State Estimation
RTDS	Real Time Digital Simulation
SCADA	Supervisory Control and Data Acquisition
SCC	Short Circuit Current Contribution

SCE	Southern California Edison
SDG&E	San Diego Gas & Electric Company
SEL	Schweitzer Engineering Laboratories
SIR	Synthetic Inertia-like Response
SVC	Static Var Compensator (Thyristor based design)
TCR	Thyristor Controlled Inductor
TSC	Thyristor Switched Capacitors
V	Volt
VAR	Volt-ampere Reactive
WAMS	Wide Area Monitoring System
WAMC	Wide Area Monitoring and Control System
WECC	Western Electricity Coordinating Council
WI	Western Interconnection

1 Executive Summary

Project Introduction

As California pursues its policy objective of reducing carbon emissions from the power system, Southern California Edison (SCE) is undergoing rapid changes in its generation resource mix. Increasing amounts of renewable generation are causing a corresponding decrease in conventional generation (synchronous machines), such as gas-fired plants.

A shift away from synchronous machine-based generation technologies and toward inverter-based, renewable power generation will decrease the total inertia of the bulk power system. Inertia-based generation supports system stability during sudden disruptions (such as the loss of major loads, generators or lines) caused by contingency events. Thus, a decrease in inertia could endanger system stability.

A key stability issue is the phenomenon of low-frequency, electro-mechanically induced, inter-area oscillations. When groups of generators are operated together (synchronously) in a large power system, some may slow down more than others. This causes groups of generators to oscillate against one another, or some generators to oscillate against the rest of the system. These small oscillations, if undamped or under-damped, can cause a loss of synchronization for several machines and can lead to a blackout. (Damping is a process that gradually reduces excessive oscillations and thus supports power system stability during disruptions.)

Changing power system conditions are raising concerns for reliability organizations, such as the North American Electric Reliability Corporation (NERC), as indicated in its 2018 reliability guidelines. Furthermore, these changing conditions also raise concerns for power system operators and utilities (including SCE) regarding the impact of reduced inertia on grid operations, control, Short Circuit Capacity (SCC), reliability, and stability of the bulk energy system (BES).

Project Description, Components and Findings

Given the evolving energy system landscape, SCE undertook the Wide Area Management and Control Project to determine the technology capabilities and requirements that can enable deployment of advanced inverter control functions to maintain grid reliability. Specifically, this project sought to demonstrate how power electronics-based technologies may provide synthetic inertia functions to meet the increasing needs for stability and safety on the electric grid. Understanding how inverters can provide these functions can drive effective deployment of solar, wind and storage-based generation on SCE's system.

In the project, poorly damped inter-area oscillatory modes in the Western Electricity Coordinating Council (WECC) system were identified via a series of dynamic simulations. An evaluation called the Prony analysis technique was used to determine the frequency and damping coefficient of the inter-area modes.

The components of the project were:

1. Conducting real-time monitoring of the SCC at SCE's Devers Substation to understand the impact of high penetration of renewable energy resources on BES operation and control.
2. Activating the Power Oscillation Damping (POD) of the Devers Static VAR Compensator (SVC), and tuning the POD controller to improve the overall system damping.

The project indicated that SCC will be highly impacted by increased penetration of renewable energy resources. Generally, improvements of damping coefficients of the inter-area oscillation modes were observed. In addition, the performance of the POD was demonstrated and the effectiveness in damping the oscillations was confirmed under different system contingencies and outages. (See Section 4, Project Summary, for more details on the project components and findings.)

The project's results are also transferrable to future testing and interconnection standards for battery storage, solar photovoltaic (PV) or other inverter-based generation, enhancing the ability to safely and reliability integrate these technologies into SCE's electric system.

2 Project Background

The growth in use of intermittent generation resources (like solar and wind), combined with the retirements of once-through cooling conventional power plants, likely will negatively impact BES stability, which is currently supported by conventional generation stations (synchronous machines). A shift away from synchronous machine-based generation technologies and toward inverter-based, renewable power generation will decrease the total inertia of the bulk power system. Inertia-based generation supports system stability during sudden disruptions caused by contingency events. Thus, inertia provides innate and critical support characteristics to the entire interconnected grid, and its decrease could endanger system stability.

Given the necessity of ensuring grid stability with the growing use of inverter-based, renewable power generation, there is a need to emulate damping, a process that gradually reduces excessive oscillations and thus supports power system stability during BES events.

This can be achieved using additional control schemes in Flexible AC Transmission Systems (FACTS) devices such as SVCs and inverter-based energy resources to emulate damping to support the system during events. For example, for an SVC, the control scheme will vary the output of the SVC, in a way that enables POD by dynamic control of system voltage. The variations must be such that damping torque or accelerating power is injected optimally to reduce the oscillations and thus provide damping enhancement.

An SVC is one FACTS device used as a power oscillation damper in transmission and sub-transmission grids. The other is a Thyristor Controlled Series Capacitor (TCSC).

Oscillations

As noted in the Executive Summary, a key stability issue is the phenomenon of low-frequency, electro-mechanically induced, inter-area oscillations. When groups of generators are operated together (synchronously) in a large power system, the response of each of them to load changes is not the same. Some may slow down more than others. This causes groups of generators to oscillate against one another, or some generators to oscillate against the rest of the system. These small oscillations, if undamped or under-damped, can cause a loss of synchronization for several machines and can lead to a blackout. The last such event in the WECC region (in 1986) occurred due to low-frequency oscillations that propagated into a system-wide blackout.

Low-frequency inter-area power oscillations are a common phenomenon arising between groups of rotating power generators in the WECC, interconnected by weak and/or heavily loaded alternating current (AC) interties. Such oscillations can be excited for several reasons, such as line faults, line switching or a sudden change in generator output. Inter-area oscillation frequencies typically occur below 2 hertz (Hz), and constitute a restraint on power transmission capability over the tie. Damping or altogether alleviating the power oscillations brings the valuable benefit of increased power transmission capability over the existing interconnector.

Damping Devices

Typically, a device such as an SVC has a local controller designed to monitor and control a system variable such as voltage. To achieve such control, the SVC absorbs or generates reactive power. The thyristor switched capacitors (TSC) in an SVC supply reactive power to the network, while the thyristor controlled reactors (TCR) absorb reactive power. The thyristor firing angles can be changed depending on the amount of reactive power required by the network. Changing this amount in a certain coordinated way creates a damping action. A supplementary control signal can be added to the SVC to achieve this damping action, but caution must be exercised to ensure it does not interfere with the device's normal operation.

With an SVC, POD is achieved by dynamic control of the system voltage in such a way that during upward portions of the power versus time profile, the SVC (or SVCs) support(s) the voltage, thereby acting to slow down the motion of the rotating machine(s). Likewise, during downward portions of the power versus time profile, the SVC is controlled to decrease the system voltage, thereby acting to accelerate the rotating machine(s). By doing so for a limited amount of time, the power oscillations are damped out and system stability is protected.

3 Project Summary

The components of the Wide Area Management and Control Project were:

1. **Conducting real-time monitoring of the SCC at SCE's Devers Substation**. This is the first SCC monitoring system in the U.S. It enabled SCE grid operators and planners to understand the impact of high penetration of renewable energy resources on BES operation and control.
2. **Activating the Devers SVC POD, and tuning the POD controller to increase the damping coefficients of inter-area modes with low damping.** The activation of the SVC POD represented the first time SCE used FACTS devices-based damping to increase the stability margins of the BES.

In general, improvements of damping coefficients of the inter-area oscillation modes were observed. Additional conclusions of the demonstration were:

1. SCC will be highly impacted by increased penetration of renewable energy resources, which will affect system operation, protection and control. With the implemented Supervisory Control and Data Acquisition System (SCADA)-based SCC monitoring system, grid operators and planners will have the ability to predict future impacts and possible mitigations.
2. Several known (reported in literature) inter-area oscillatory modes from 0.2 Hz to 0.8 Hz can be observed at Devers Substation. The POD controller was tuned to improve damping coefficients of low damped inter-area modes. The performance of the POD was demonstrated and the effectiveness in damping the oscillation was confirmed under different system contingencies and outages.
3. Once the POD was enabled, a change in the Devers SVC voltage (compared to the voltage without the POD) was observed. The change had the same frequency of the oscillation mode, which is required to be damped. This was observed in most of the fault recovery conditions studied, and proved that the inter-area mode was "*observable*" in the selected input (frequency deviation of the Devers 500-kilovolt (kV) bus).
4. However, the frequency of the Devers bus or the power transfer in 500-kV double circuit lines through Devers showed a change in only some of the fault recovery conditions studied. This indicated that only some of the inter-area oscillations were "*controllable*" (could be influenced by the Devers SVC).

The Wide Area Management and Control Project was proposed as part of SCE's Electric Program Investment Charge (EPIC) investment plan application.[1] EPIC, adopted by the California Public Utilities Commission (CPUC) in 2011, aims to fund applied research and development technology demonstrations and deployments, as well as market facilitation programs, for the benefit of ratepayers of California's investor-owned utilities (IOUs).

During the first EPIC triennial (2015-2017) planning period, the IOUs collaborated to develop a common methodology for assessing technology demonstrations and deployments. This Joint

[1] *See* "Application (A.)14-05-005 amendment to Application of Southern California Edison Company (SCE) for Approval of Its 2015-2017 Triennial Investment Plan for the Electric Program Investment Charge," May 1, 2014, for more details on the EPIC program and SCE's investment plan.

Utilities EPIC Framework, which the CPUC adopted, presents a broad spectrum of smart grid capability gaps.

Based on the Joint Utilities EPIC Framework (Figure 1), SCE's project addressed power system reliability by demonstrating Grid Modernization and Optimization technologies to ensure grid stability, given the increasing focus on Renewables and Distributed Energy Resources Integration.

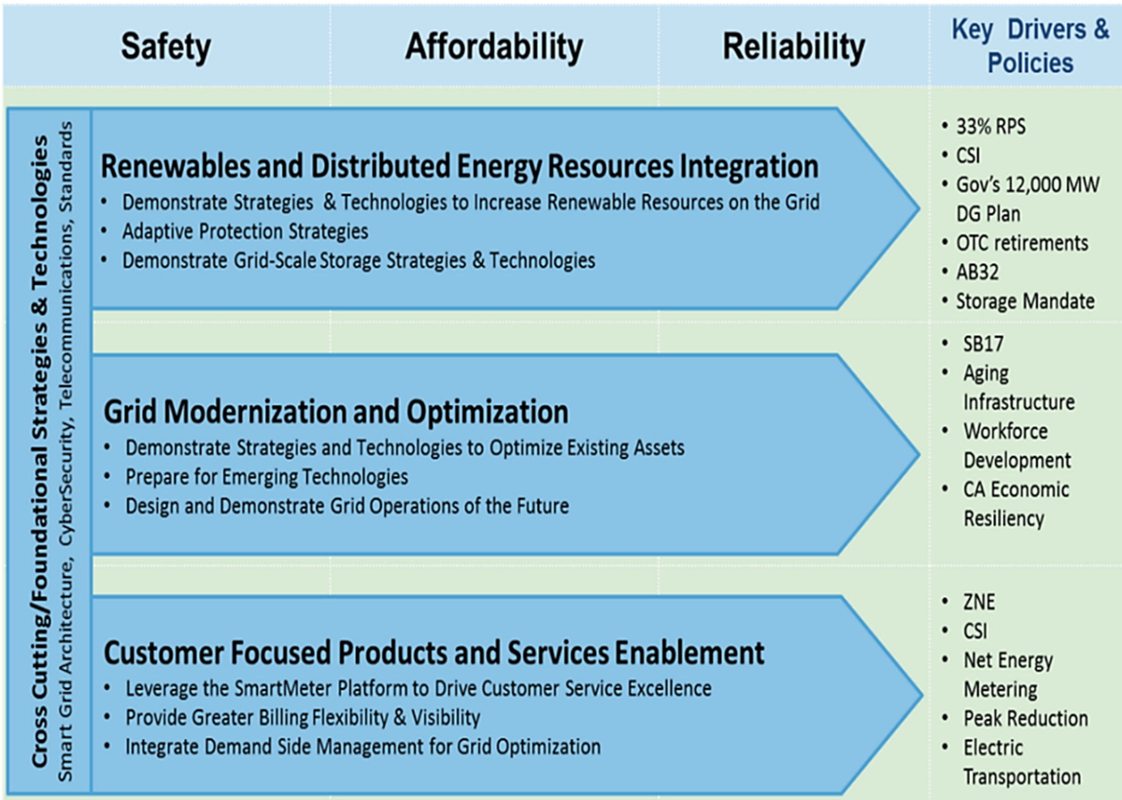

Figure 1 Joint Utilities EPIC Framework

4 Devers SVC

The Devers 500-kV Substation's SVC was installed in 2006 to improve transmission system capacity and voltage stability issues by dynamically injecting the required amount of reactive power onto the network during system events, thus supporting voltage recovery at the substation. The SVC dynamic and 1-hour emergency rating is 605 megavolt ampere reactive (MVAr) Capacitive to 110 MVAr Inductive at 525 kV. It consists of three thyristor switched capacitors, two thyristor controlled reactors, two filter banks, and a mechanically switched capacitor (MSC) connected to the high-voltage (HV) bus. The general structure of the Devers SVC, as well as the rating of its main components, is presented in Figure 2, which shows a simplified one line for the Devers SVC and surrounding substations.

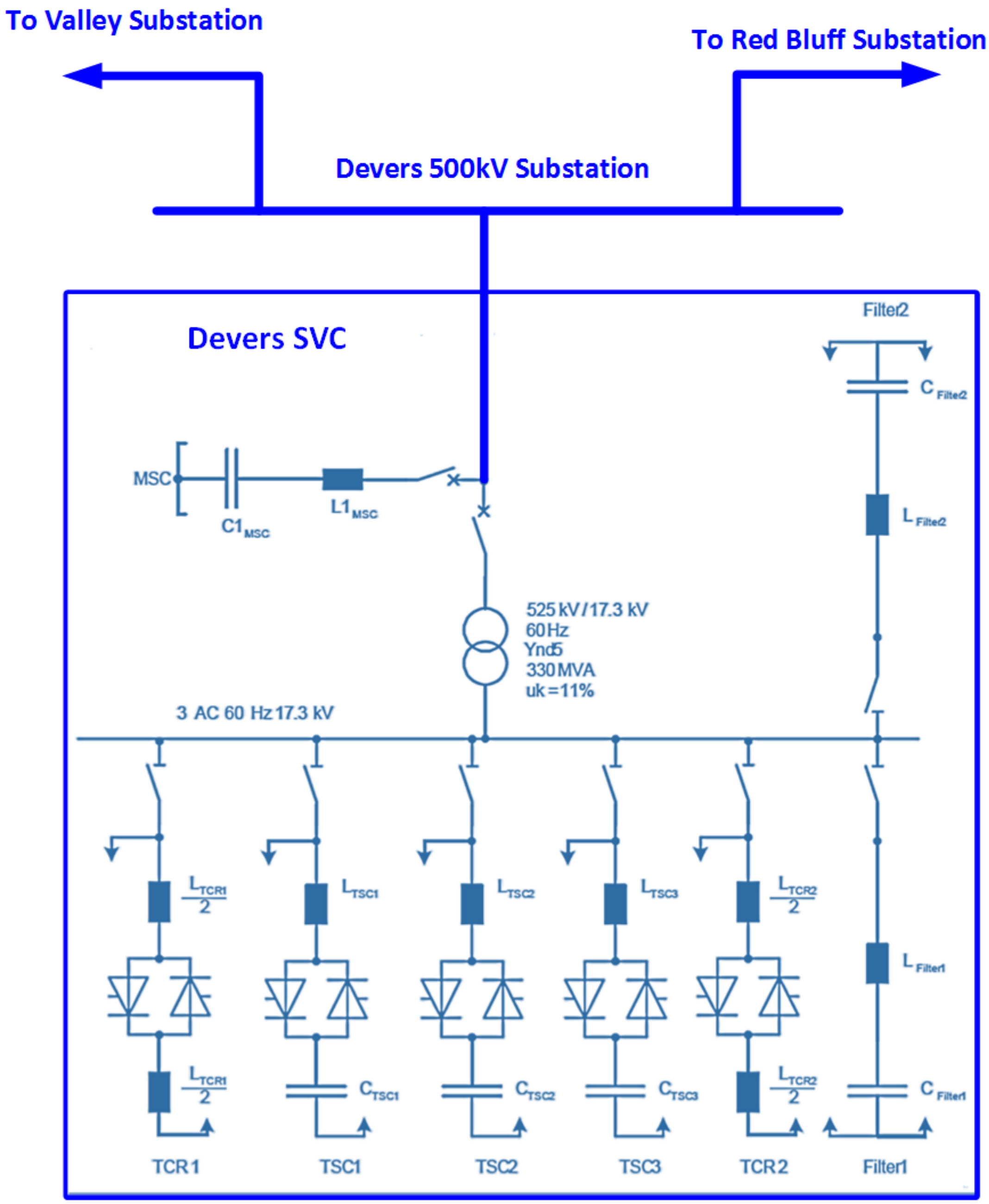

Figure 2: Devers SVC Simplified One Line

5 BES Real-Time Short Circuit Capacity Monitoring System

As penetration of renewable energy sources increases in both transmission and distribution systems, these resources do not contribute to the Bulk system short circuit Capacity. In 2015, the Essential Reliability Services Task Force (ERSTF)[2] recognized that North America's electric power

[2] Essential Reliability Services Working Group (ERSWG) and Distributed Energy Resources Task Force (DERTF).

system generation resource mix is changing from large traditional sources (e.g., gas, nuclear) to a fleet of smaller-sized resources with varying generation characteristics.

A monitoring system was implemented using the Devers SVC controller to monitor the short-circuit level at the substation and exported the data to SCE's energy management system (EMS). This represent the first system of its kind in the USA. The monitoring system will help in determining the changes needed for SCE's control and protection system to accommodate the increasingly high percentage of renewable energy penetration as well as the changes to the renewable energy control system settings.

The short-circuit capacity (SCC) is measured in order to understand the reliability implications and to quantify the risks associated with high-level integration and penetration of renewable energy resources into the bulk energy system (BES) and distribution circuits. The strength of a system (the measure of voltage stiffness) with inverter-based technologies differs from conventional generation system strength. The SCC is a screening measure to identify weak areas of the grid within the BES at a specified point (e.g., substation bus).

The accuracy of the SCC is vital in determining the settings of protection devices. Inaccuracies in power system models can lead to misoperations caused by inaccurate settings of protection devices, often directly resulting in loss of load[3]. In 2013, NERC's System Protection and Control Subcommittee researched the causes of misoperations and published the findings in the Misoperations Report that year. Investigation into the regional short-circuit cases showed incorrect short-circuit values and coordination errors. Incorrect short-circuit values were a result of outdated or incorrect data used to calculate relay settings. The coordination errors in these cases all involved pilot protection either of insufficient carrier blocking trip delays or of improper choice of ground pickup values used in a blocking scheme.

There is currently no industry standard approach to calculate an SCC index of a weak system with high penetrations of wind and solar power plants or other inverter-based resources, such as battery storage. To take into account interaction effects between generating resources and to provide a more accurate system strength index calculation, a better indicator is needed to assess the potential risk of complex instabilities.

5.1 Short Circuit Estimation Using Devers SVC

The gain controller is part of the SVC closed loop controller to keep a constant response time over a very wide range of power system short-circuit levels. This controller is a valuable addition to the SVC stability controller.

The gain controller determines the actual short-circuit level of the system and evaluates the optimum gain for the SVC voltage controller. A small amount of reactive power $\pm \Delta Q_{reg}$ is added to the actual operating point of the SVC, causing a slight voltage deviation. The actual voltage and the reactive power output of the SVC are measured before, during and after this modification.

During the measurement the voltage controller is frozen for approximately 250 milliseconds (ms) to guarantee an accurate measurement; however the measurement is cancelled immediately if a system disturbance is detected.[4]

The ratio $\Delta V_{act}/\Delta Q_{SVC}$ is a measure of the SCC of the power system at Devers Substation, which enables the evaluation of the SVC optimum gain for voltage control. The measurement is repeated up to three times if the result exceeds given tolerances. A small $\Delta V_{act}/\Delta Q_{SVC}$ measurement indicates a high short-circuit level, therefore requiring a higher gain and vice versa.

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3 NERC System Protection and Control Subcommittee's Misoperations Report, April 1, 2013.

4 Siemens AG Southern California Edison SVS Devers Design Specification-2006.

Since the SVC's installation in 2006, this calculated SCC value was local to the SVC controller and was not monitored or exported to SCE's SCADA system. To demonstrate wide area monitoring, the SCC was added to the SCADA system's steady state view, and is currently available for view in real time. Figures 3, 4, 6 and 6 show a sample of SCC values for different times in 2019. By means of measurement and recording of the SCC, the current stability condition of the power system can also be evaluated and monitored. Figure 7 shows the SCC profile during the California Independent System Operator's (CAISO) highest renewables generation serving demand on May 15 at 2:45 p.m. At this time, renewable-based generation was serving 80.3% of the system load.[5]

The analysis of the profiles shows an average of a 20%-46% drop in the SCC whenever solar generation came online, and then an increase in the SCC during the evening load peak period (around 6 p.m.).

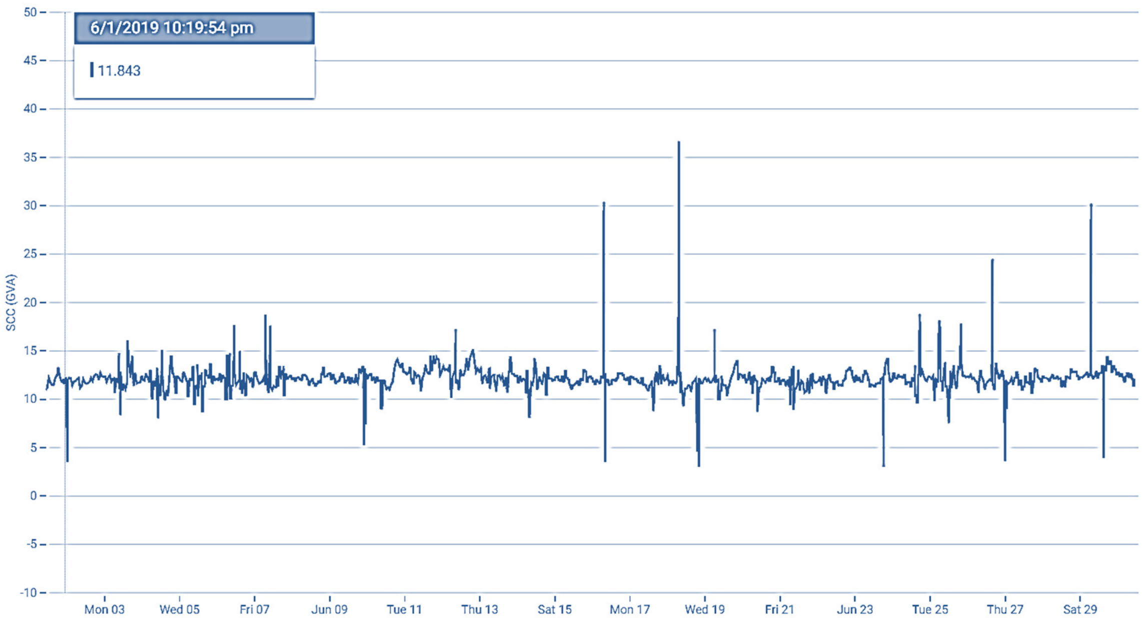

Figure 3: Real-time Variation of SCC for the Whole Month of June 2019

5 http://www.caiso.com/Documents/2019Statistics.pdf.

Figure 4: Real-time Variation of SCC for 06/01/2019 (Weekend Day)

Figure 5: Real Time Variation of SCC for 06/04/2019 (Weekday)

Figure 6: Real-time Variation of SCC for Christmas Day (12/25/2019)

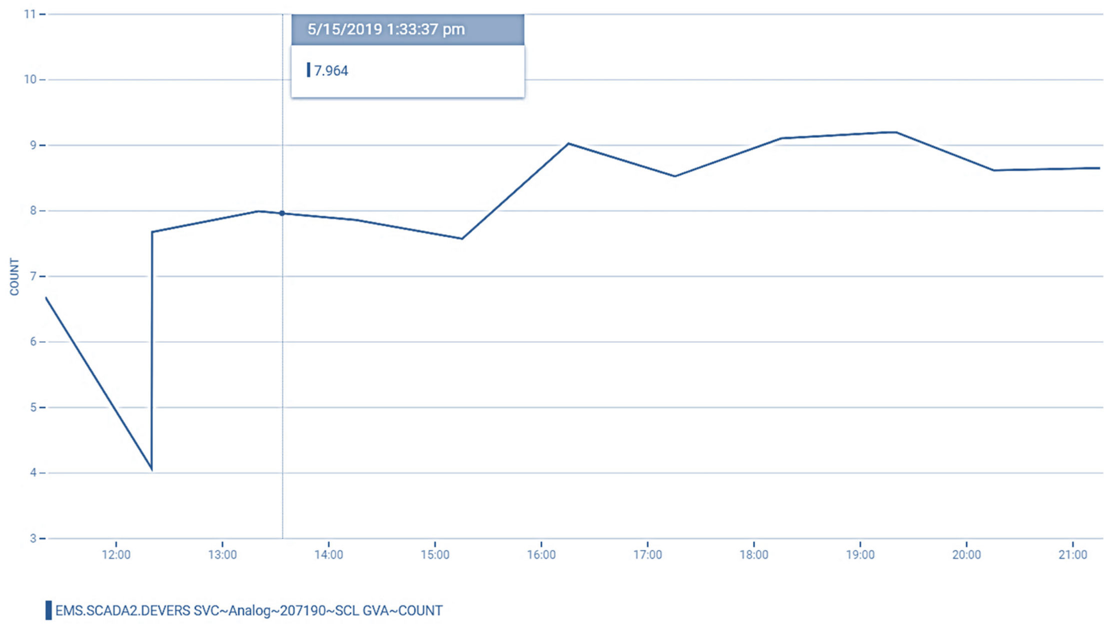

Figure 7: Real-time Variation of SCC for May 15, 2019

5.2 Impact of Monitoring Information on Operation Philosophy

Today's operation of a power system is mainly based on offline planning studies. All limits of the power system are determined by planning studies and set in a conservative way to lower the risk of system instabilities. In emergency situations it may be possible that based on the limits that are too conservative, operational actions are over-reacting. On the other hand if the planning limitations do not fit to the actual situation, operations might not be aware of the criticality of an emergency situation.

If the SCC can provide more detailed information about the actual system status, the operator can more precisely operate the system based on the real-time situation. This include oscillations mitigation, and voltage control devices settings.

6 Evaluation of Poorly Damped Modes at Devers Substation and Devers SVC POD Controller Tuning

This control feature is used for damping of power oscillations and for increasing of the transmission capability of the power system. Power oscillations occur as an interaction between power subsystems and may cause stability problems, which limit the transmission capability.

The power oscillation damping controller senses the occurrence of these oscillations automatically, enables this control circuit and generates a modulation signal EPOD (as shown in Figure 6) that is super-imposed on the voltage reference value V_{ref}. This causes a modulation of the reactive power output of the SVC, rapidly damping the oscillations. Subsequently, the POD-control circuit's gain is automatically and smoothly reduced to zero and the closed loop control thus returns to the voltage control mode.

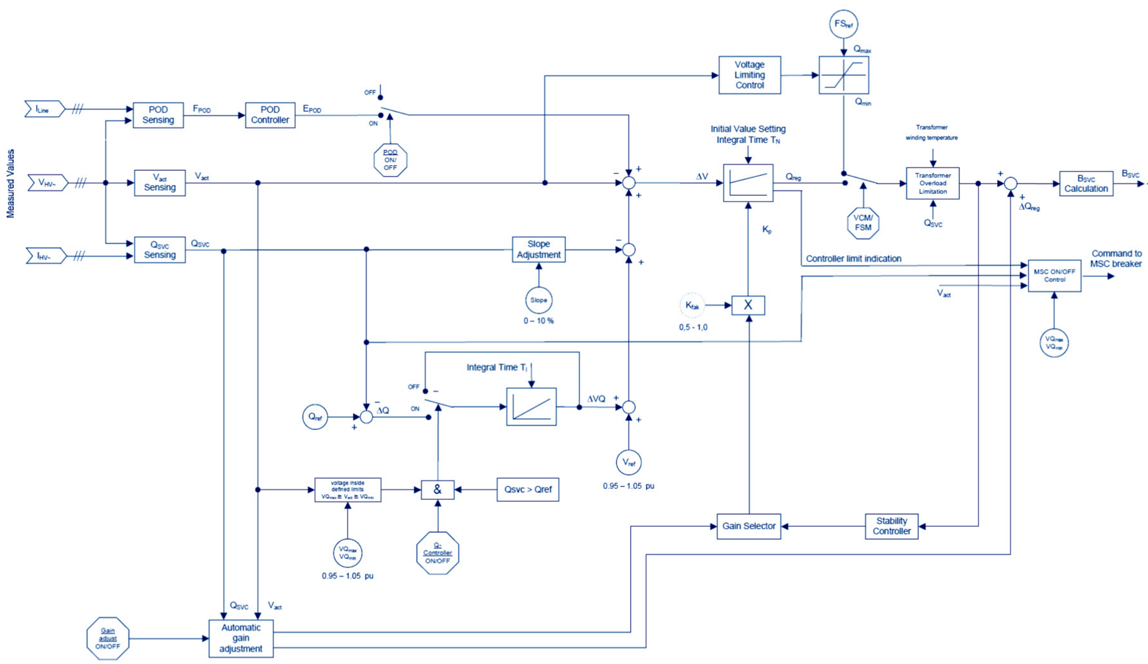

Figure 8: Block Diagram of Closed Loop Controller for SVC Devers

The following subsections specifically address the methodology and results of the investigation of the poorly damped oscillation modes at Devers Substation and the tuning of the Devers SVC Controller for Power Oscillation Damping (POD).

With high penetration of renewable generation sources, SCE system oscillation damping capability is negatively impacted due to the lack of inertia support from renewable generation sources and the reduced presence of power system stabilizers (PSS) (which have a significant influence on damping electromechanical oscillations). Also, renewable energy sources can create a low-frequency oscillation, which was encountered in both SCE's system (from April to September 2014) and in the Electric Reliability Council of Texas' (ERCOT) system (from October 2016 through spring 2017).

An understanding of SCE's system is critical for assessing impacts of events, such as those that cause lightly or negatively damped electromechanical oscillations in power systems.

The Devers Substation is located in the Western Electricity Coordinating Council (WECC) system near Los Angeles. The WECC system is shown in Figure 9 with the 500 kV Devers bus and the Pacific DC Intertie (PDCI) marked red. The PDCI is the largest HVDC corridor in the system and plays an important role in inter-area damping performance of the WECC system.

Figure 9 shows Devers 500 kV and the surrounding substations.

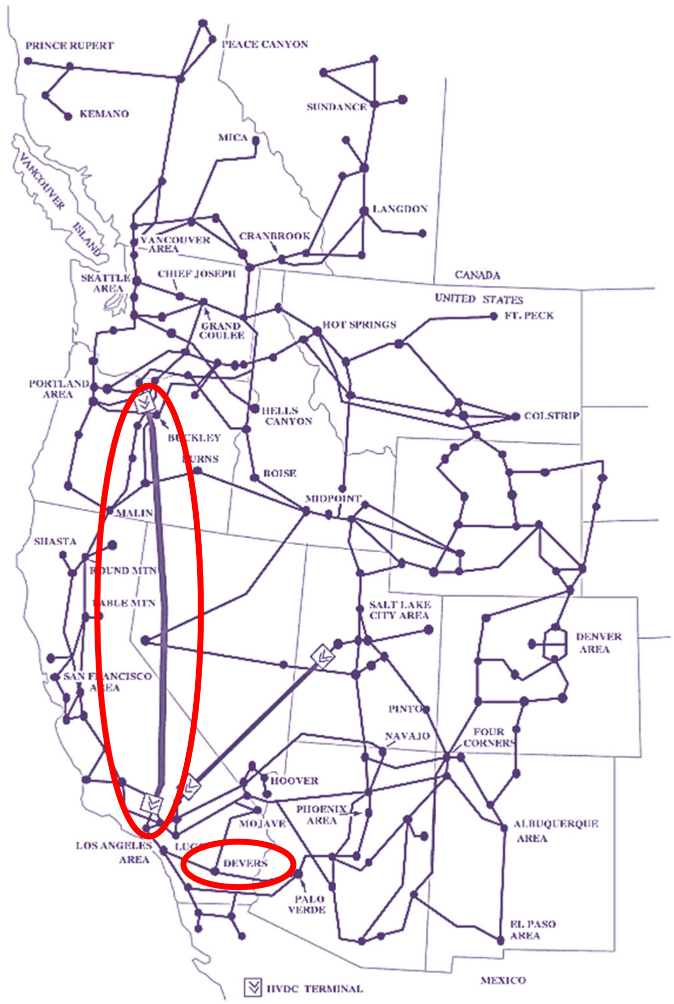

Figure 9: Western North America power system layout with major lines shown

The SVC controls the voltage at the Devers 500-kV bus and is also expected to improve the damping of inter-area modes by employing the POD controller, which is built into a user-written SVC model developed by Siemens (Germany). The input signal for the POD is the frequency at the Devers bus.

Four cases depicting different system-operating conditions were used in this demonstration. The system dynamic performance following selected disturbances were studied under all four operating conditions. The use cases were created by WECC and are described in section 6.1.1 of this report. Descriptions of the disturbances applied to each study case (a total of 16) are given in section 6.1.1.

For each case, the tuned parameters of the POD and a comparison of the damping coefficients with and without the POD are shown in sections 6.1, 6.2, 6.3 and 6.4. The demonstration conclusions are presented in section 6.

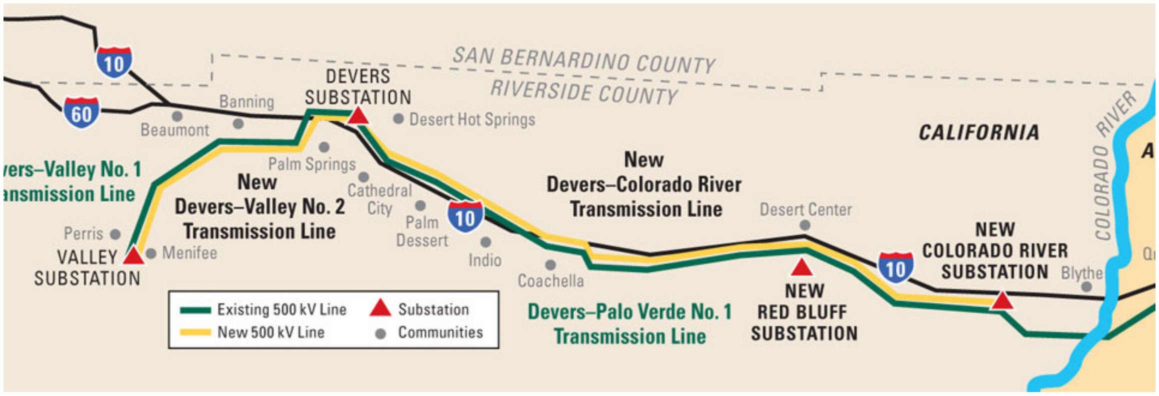

Figure 10: Devers Substation and substations in its vicinity[6]

6.1 Identification of Oscillation Modes

An assessment was conducted using WECC-approved static and dynamic cases for current and future system configuration. The goal was to perform simulations of a number of contingencies both without and with the POD controller, and to evaluate the damping effect of the tuned POD controller by comparing the amplitudes and damping of the power oscillations for both simulations.

A user-written dynamic PSSE model of the SVC was developed that includes the POD controller as well as the SVC's other control functions.

The power flow model consists of a switched shunt device representing the Thyristor Control Reactor (TCR) and Thyristor Switched Capacitor (TSC) components. The filters are combined in one fixed shunt element. The Mechanically Switched Capacitor (MSC) is built as a fixed shunt model at the HV side of the SVC transformer.

6.1.1 Analysis of PMU Data for Devers Substation

SCE has a Phasor Measurement Unit (PMU) installed at Devers Substation. The PMU data is captured every 3 minutes and saved to a server. SCE automated the process to read the files and calculate the dominant modes and their damping for the whole year of 2017 using SCE's Power System Outlook tool (PSO). Figure 11 shows a sample output for PSO for an event. The results show that various modes between 0.103 Hz and 1.7 Hz occur at Devers Substation with a damping ratio of less than 5%. The smallest damping ratios exist for frequencies around 0.75 Hz. In total there were 4,822 events causing oscillations with less than 5% damping.

6 https://www.sce.com/about-us/reliability/upgrading-transmission/dpv2.

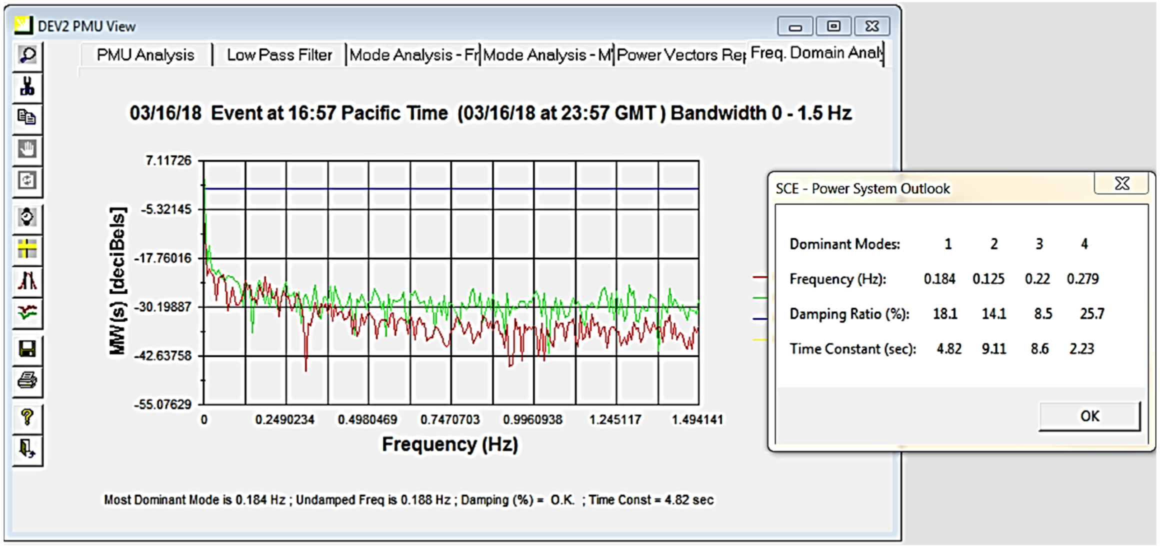

Figure 11 SCE PSO Output display

6.1.2 Use Cases

Four use cases depicting four system-operating conditions were used in this demonstration. The system dynamic performance following selected disturbances were evaluated under all four operating conditions.

Table 1: Stressed cases

Case	Description	SCE load [MW]	SCE generation [MW]	PDCI power [MW]	COI power [MW]
17hsp1ap	WECC 2017 high spring base case	15,583	8,783	2,400	3,867
18hs4ap	WECC 2018 high summer base case	22,529	15,414	1,954	4,146
21hw1ap	WECC 2021 high winter base case	14,528	10,233	1,180	1,920
22HS1ap	WECC 2022 high summer base case	22,853	18,488	2,711	4,210

Two of the use cases were stressed by decreasing the power transfer in the PDCI, which causes increased loading in the COI. The new power transfers are shown in Table 1, and were used for all subsequent evaluations. Cases listed in Table 1 were used to evaluate system dynamic performances during the post-disturbance period in order to identify poorly damped inter-area modes. The disturbances were simulated and the system performance was observed during these events. Table 2 summarizes the critical contingencies considered in the assessment.

Table 2: Contingencies considered in the POD design

Contingency	Type	Description
Chief Joseph Brake Insertion	Switching	A 1400-MW dynamic brake resistor is inserted at Chief Joseph Substation, for a duration of 0.5 seconds.
British Columbia (BC) to Northwest Separation	Transmission lines and generation tripping	Separation from BC from the WECC Northwest.
Pacific AC intertie lines (Path 66) series capacitor bypassing	Switching	Bypassing some of the Path 66 lines series compensation.
Double Circuits fault around Path 66 500kV substations	Faults (N-2)	Creating a fault on the line and tripping two transmission lines at the same time to clear the fault (N-2).
Shunt Capacitor Switching on substations along Path 66	Switching	Switching 500 kV shunt capacitors.
Tripping two units of Palo Verde generation station	Generation tripping	Tripping two units of Palo Verde Generation Station.
Pacific DC Intertie Blocking (Path 65)	HVDC line blocking	The Pacific DC Intertie is blocked at 0.5 seconds, and remains blocked for the duration of the simulation.
500kV substation outage along Path 66	Substation outage	A solid three-phase fault is applied at the substation end of the 500- kV line. The fault is cleared by tripping all lines connected to the substation after five cycles.

6.1.3 Prony Analysis Results Without the Devers SVC POD Enabled

Time domain simulations were performed using the PSSE dynamic simulator to evaluate system behavior following the disturbances listed in Table 1. The Prony analysis tool built in the PSS®E plotting tool PSSPLT™ was used to analyze selected time domain signals observed during system recovery following the disturbances. The measurements chosen for Prony analysis were the voltage and frequency at the Devers 500-kV bus, the active power in the Devers-Redbluff circuit, and the active power in the Devers-Valley circuit.

All of the disturbances described were applied to each of the four use cases. However, not all of the disturbances produced poorly damped modes in the signals measured at Devers.

Utilizing the Prony analysis method, the damping ratios of the identified modes are shown in Figure 12~~12~~ below.

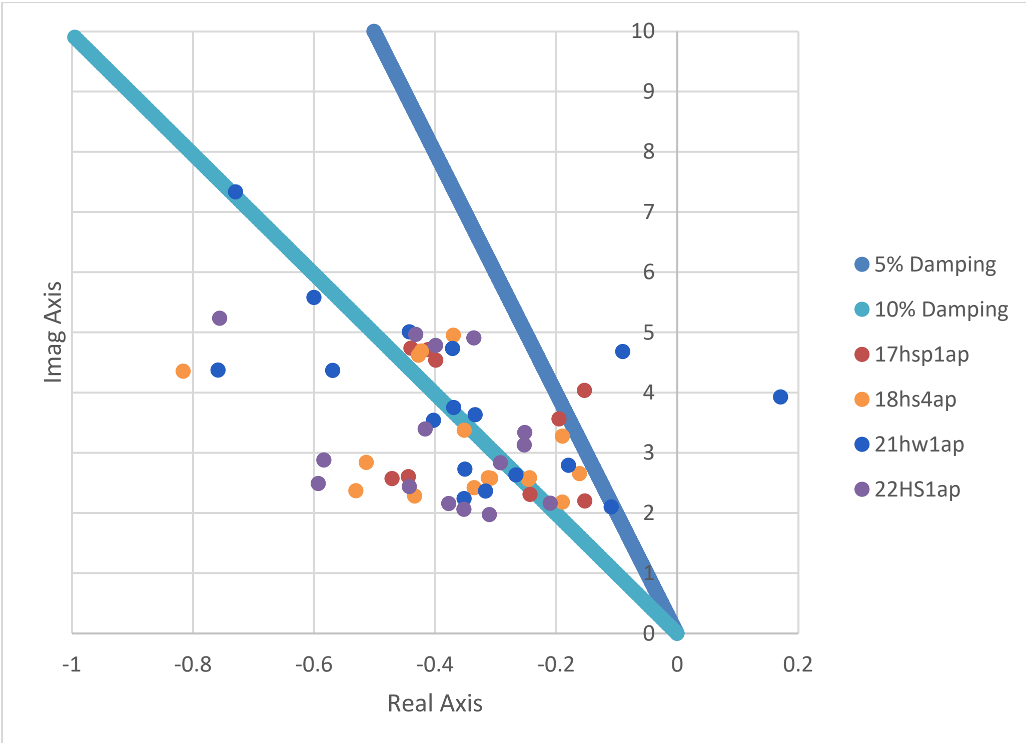

Figure 12: Cases comparison without the POD ('Prony analysis' method)

As shown, a few modes were negatively damped for the 21hw1ap case. The 17hsp1ap, 18hs4ap and 22HS1ap cases generally had all modes greater than 5%, with the majority of the modes having damping ratios greater than 10%.

7 Mitigating Poorly Damped Inter-Area Modes

The modes described in the following sections were analyzed in two groups: 1) for disturbances close to the SVC at Devers, and 2) for disturbances located further away.

7.1 High Load Spring Season of 2017 Case

For this case, the POD parameters were tuned to improve the damping performance of the modes listed in the previous section and are listed in Table 3.

Table 3: POD parameters for case '17hsp1ap'

CON	Name	Value
J+15	POD Gain	0.5000
J+16	PT1 time constant [s]	0.0531
J+17	POD Wash-out filter differential time constant [s]	0.2186

J+18	POD Wash-out filter lag time constant [s]	0.5305
J+19	POD Lead-Lag filter 1 lead time constant [s]	0.6322
J+20	POD Lead-Lag filter 1 lag time constant [s]	0.4452
J+21	POD Lead-Lag filter 2 lead time constant [s]	0.6322
J+22	POD Lead-Lag filter 2 lag time constant [s]	0.4452
J+23	POD Lead-Lag filter 3 lead time constant [s]	0.6322
J+24	POD Lead-Lag filter 3 lag time constant [s]	0.4452
J+25	POD limit [pu, based on nominal voltage of HV busbar]	0.05

The frequency response of the POD with the above parameters is shown in Figure 13.

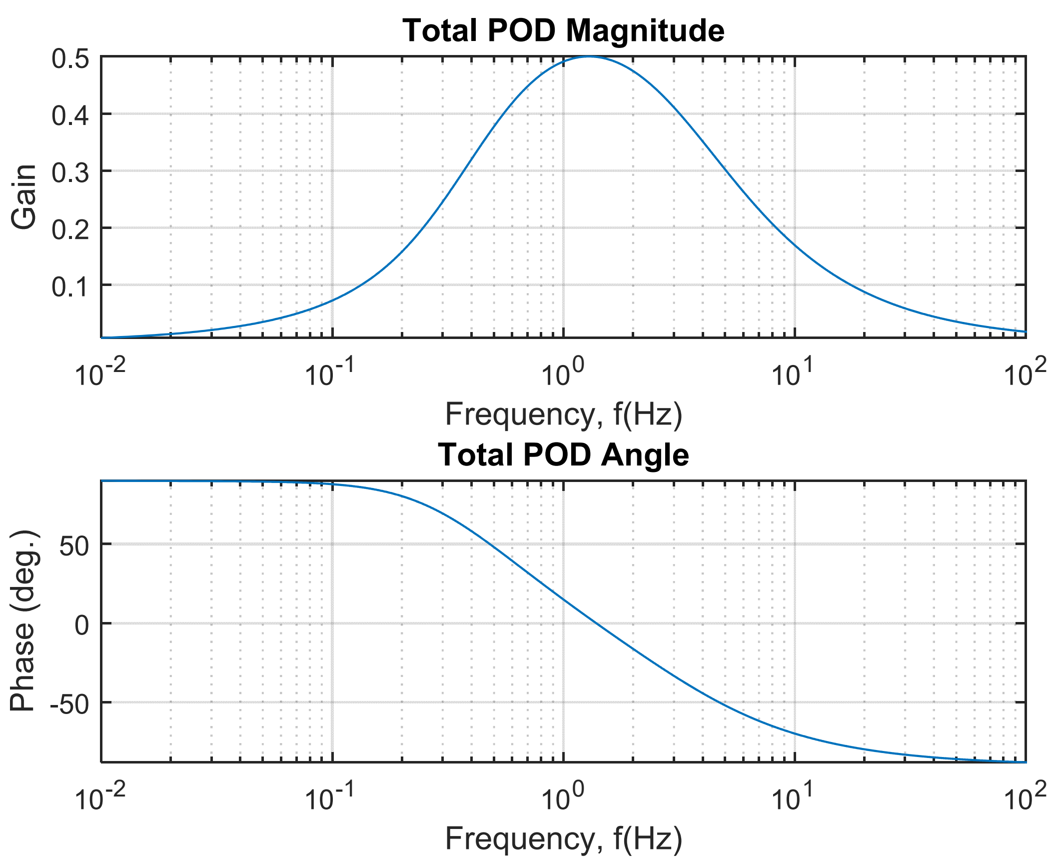

Figure 13: POD frequency response for case '17hsp1ap'

7.1.1 Disturbances Located Close to Devers Substation

The identified modes at the Devers Substation for the disturbances located close to the SVC are shown in Table 44.

Table 4: Observable modes @ Devers Substation using Prony analysis methods for with and without the POD

Disturbance	Channel	Without POD		With POD	
		Damping	Frequency	Damping	Frequency
Lugo - Mira Loma	P (Devers-Redbluff)	9%	0.72	12%	0.74
Devers - Redbluff	P (Devers-Valley)	9%	0.75	9%	0.74
Devers -Valley	P (Devers-Redbluff)	9%	0.75	10%	0.74

The results show that the POD had very little effect on improving the damping ratios of the selected active power signals. Figure 14 through Figure 19 show the voltage and frequency at the 500-kV Devers bus and the active power transfers in the 'Devers-Redbluff' and 'Devers-Valley' circuits. The channels in blue are the results with the POD and the channels in green are the results without the POD.

The start time of the window used for the Prony analysis method was always selected to occur at least 2 seconds after the fault was applied. This was done to minimize any non-linearity in the signal that could have reduced the accuracy of the results. The following plots show the same signals as above on a different time window that corresponded more closely to the time window selected for the Prony analysis.

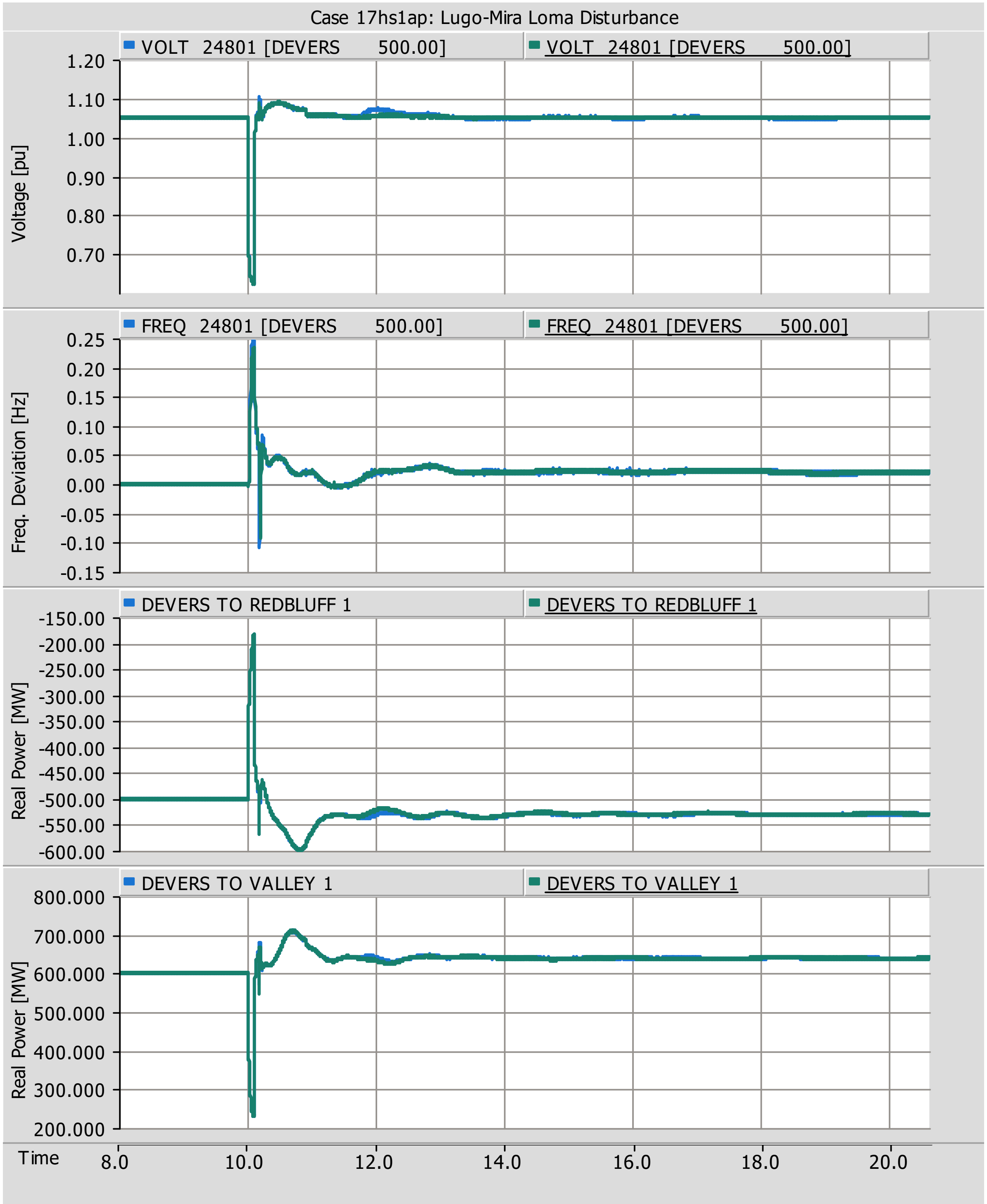

Figure 14: Results with and without the POD for the 'Lugo - Mira Loma' disturbance

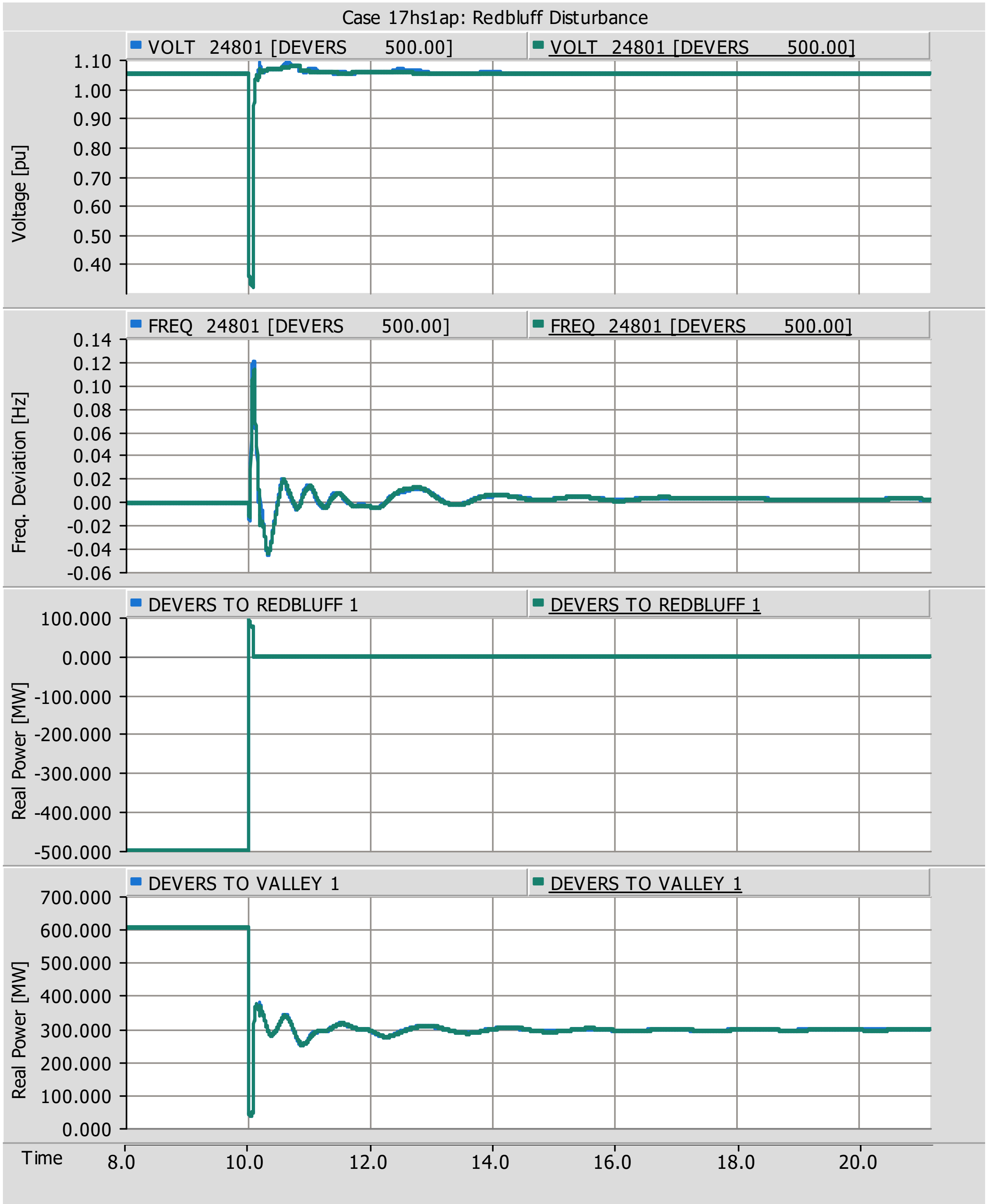

Figure 15: Results with and without the POD for the 'Devers – Redbluff' disturbance

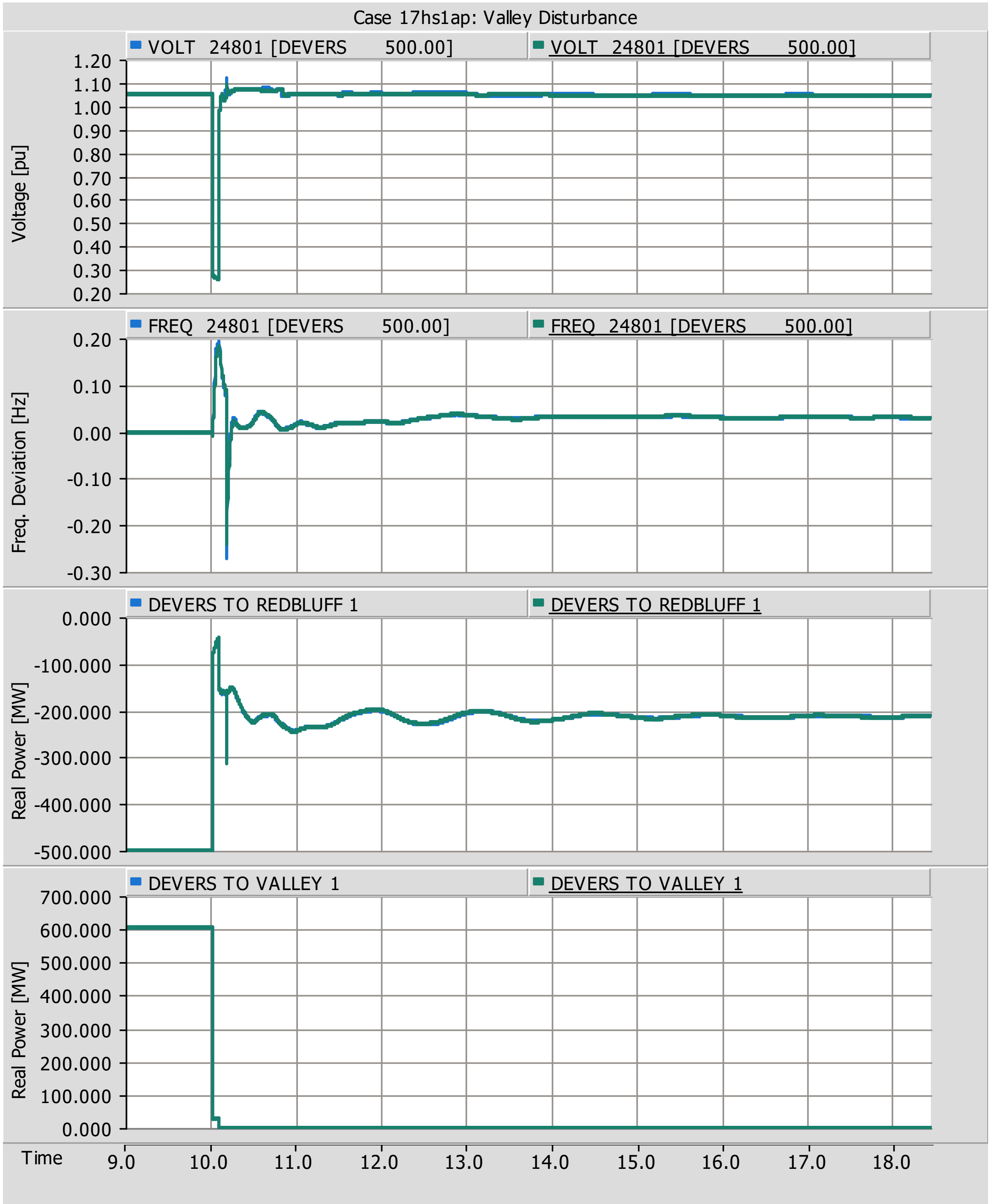

Figure 16: Results with and without the POD for the 'Devers – Valley' disturbance

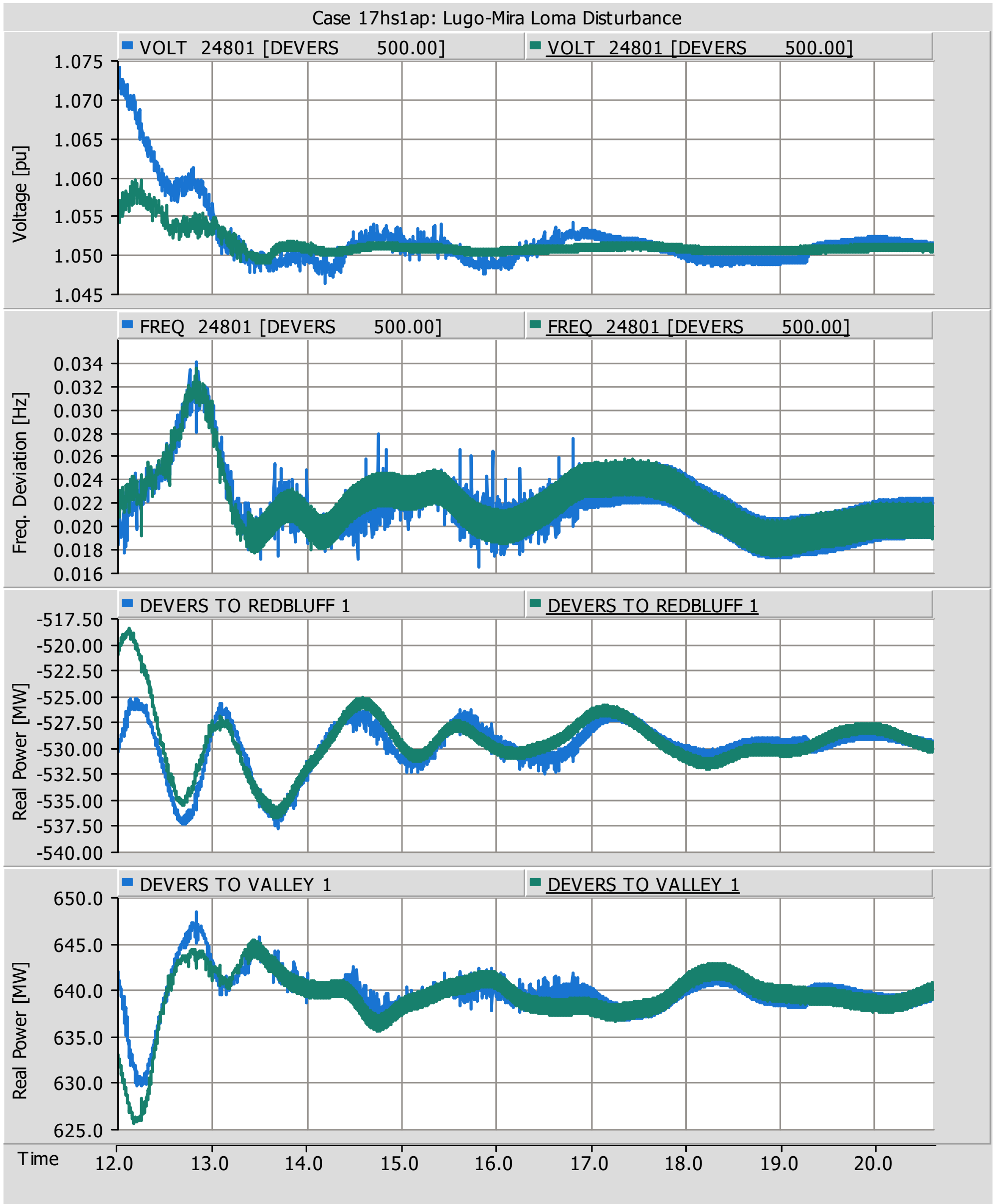

Figure 17: Results with and without the POD for the 'Lugo - Mira Loma' disturbance

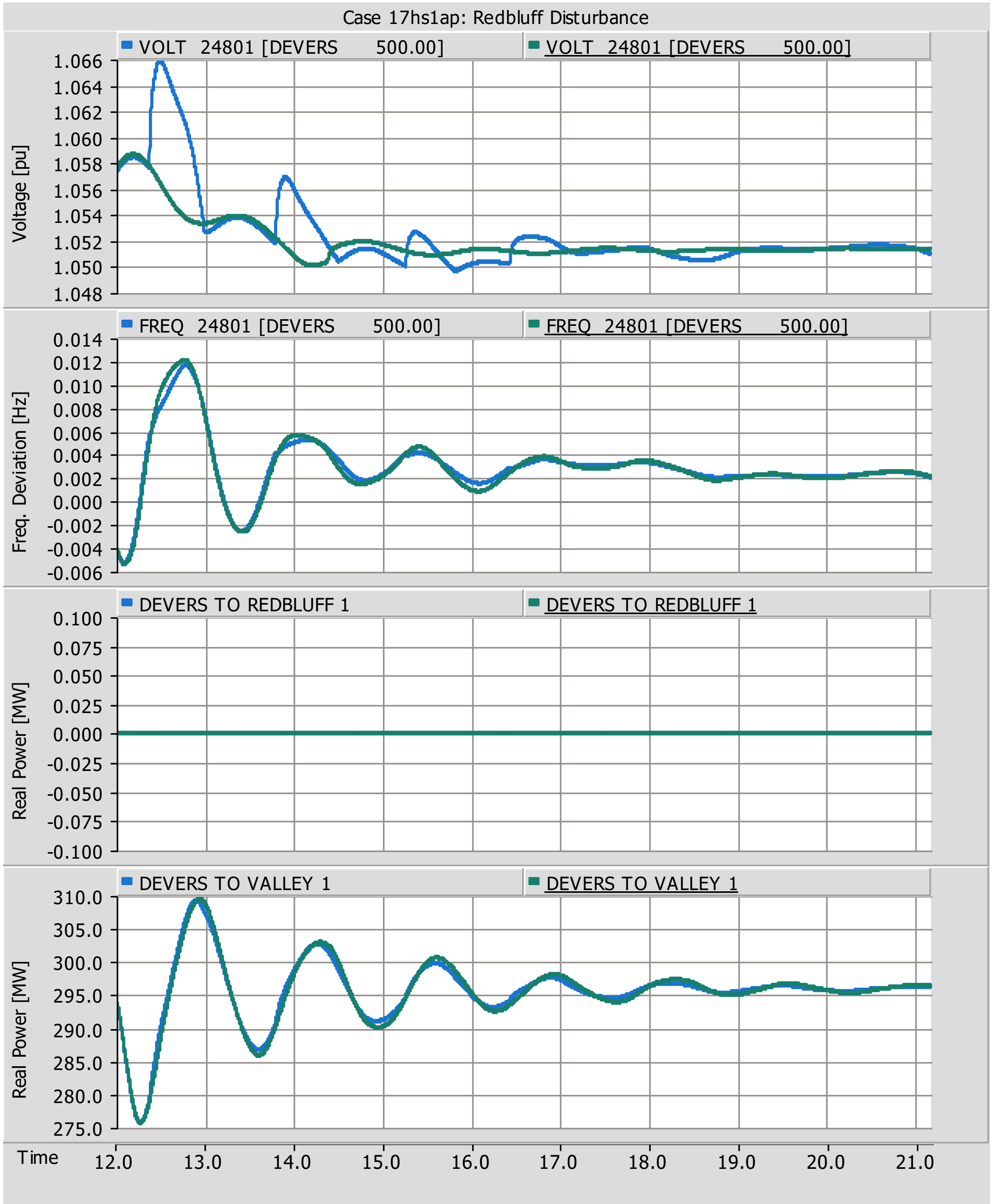

Figure 18: Results with and without the POD for the 'Devers – Redbluff' disturbance

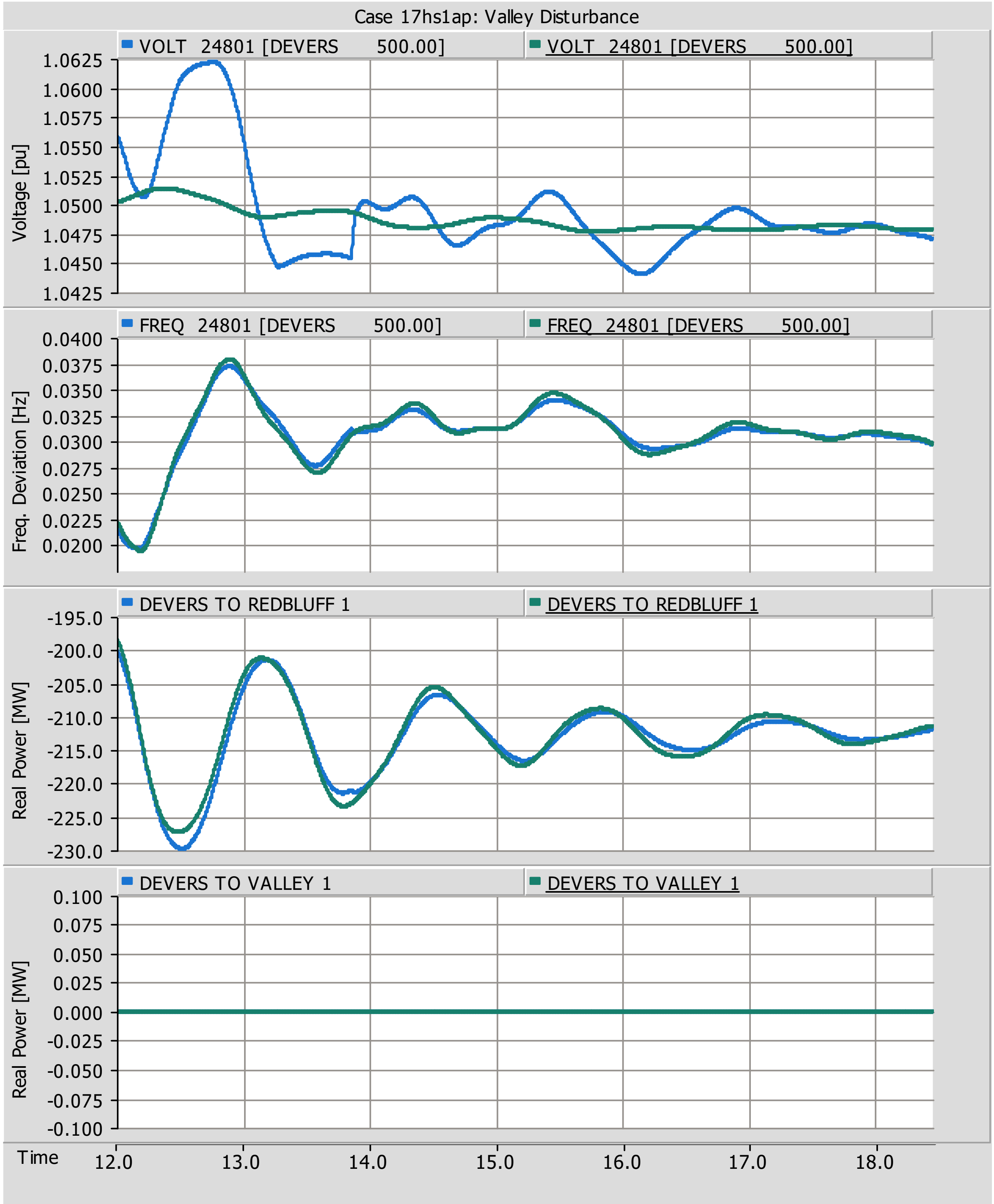

Figure 19: Results with and without the POD for the 'Devers – Valley' disturbance

7.1.2 Disturbances Located Far Away from the SVC at Devers

The identified modes at the Devers Substation for the disturbances located far from the SVC are shown in Table 55.

Table 5: Observable Modes Using the Prony Analysis Method With and Without the POD

Disturbance	Channel	Without POD		With POD	
		Damping	Frequency	Damping	Frequency
BC - NW Separation*	P (Devers-Redbluff)	5%	0.57	9%	0.57
Captain Jack Shunt Capacitor	P (Devers-Redbluff)	18%	0.41	25%	0.34
Chief Joseph Brake Insertion	P (Devers-Redbluff)	7%	0.35	11%	0.37
Malin Shunt Capacitor	P (Devers-Redbluff)	17%	0.41	18%	0.42
Summer Lake Outage	P (Devers-Redbluff)	10%	0.37	6%	0.49
Captain Jack Shunt Capacitor	Frequency (Devers)	11%	0.34	15%	0.46
Malin Shunt Capacitor	Frequency (Devers)	16%	0.34	16%	0.45
Summer Lake Outage	Frequency (Devers)	9%	0.41	12%	0.35

* The BPA Fast AC Reactive Insertion (FACRI) scheme was activated for this disturbance

The results show a higher damping ratio with the POD. For the cases with the POD, there is a larger difference in the results between the two methods. Figures 20 through 24 show the voltage and frequency at the 500 kV Devers bus and the active power transfers in the 'Devers-Redbluff' and 'Devers-Valley' circuits. The channels in blue are the results with the POD and the channels in green are the results without the POD.

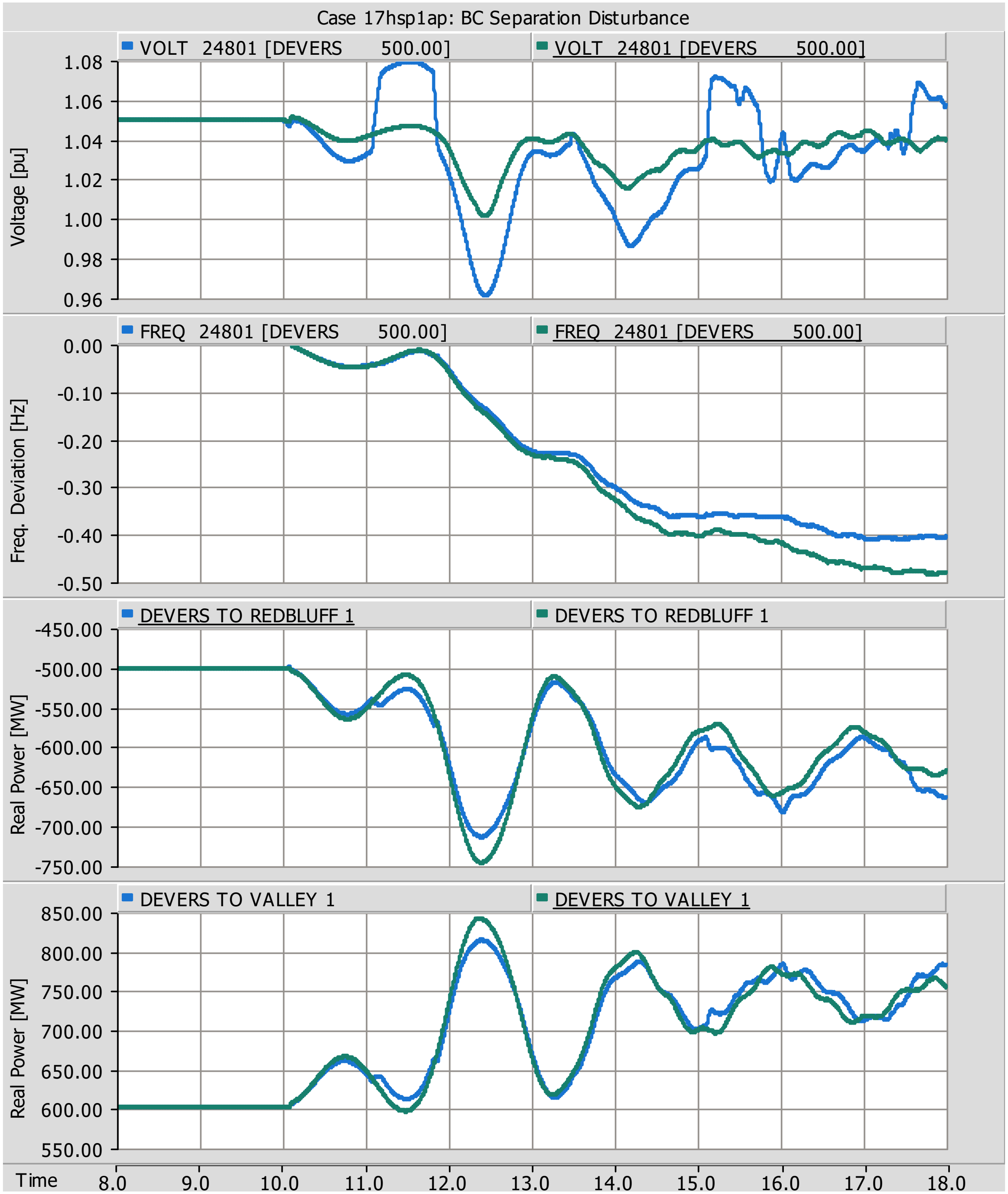

Figure 20: Results with and without the POD for the 'BC – NW Separation' disturbance

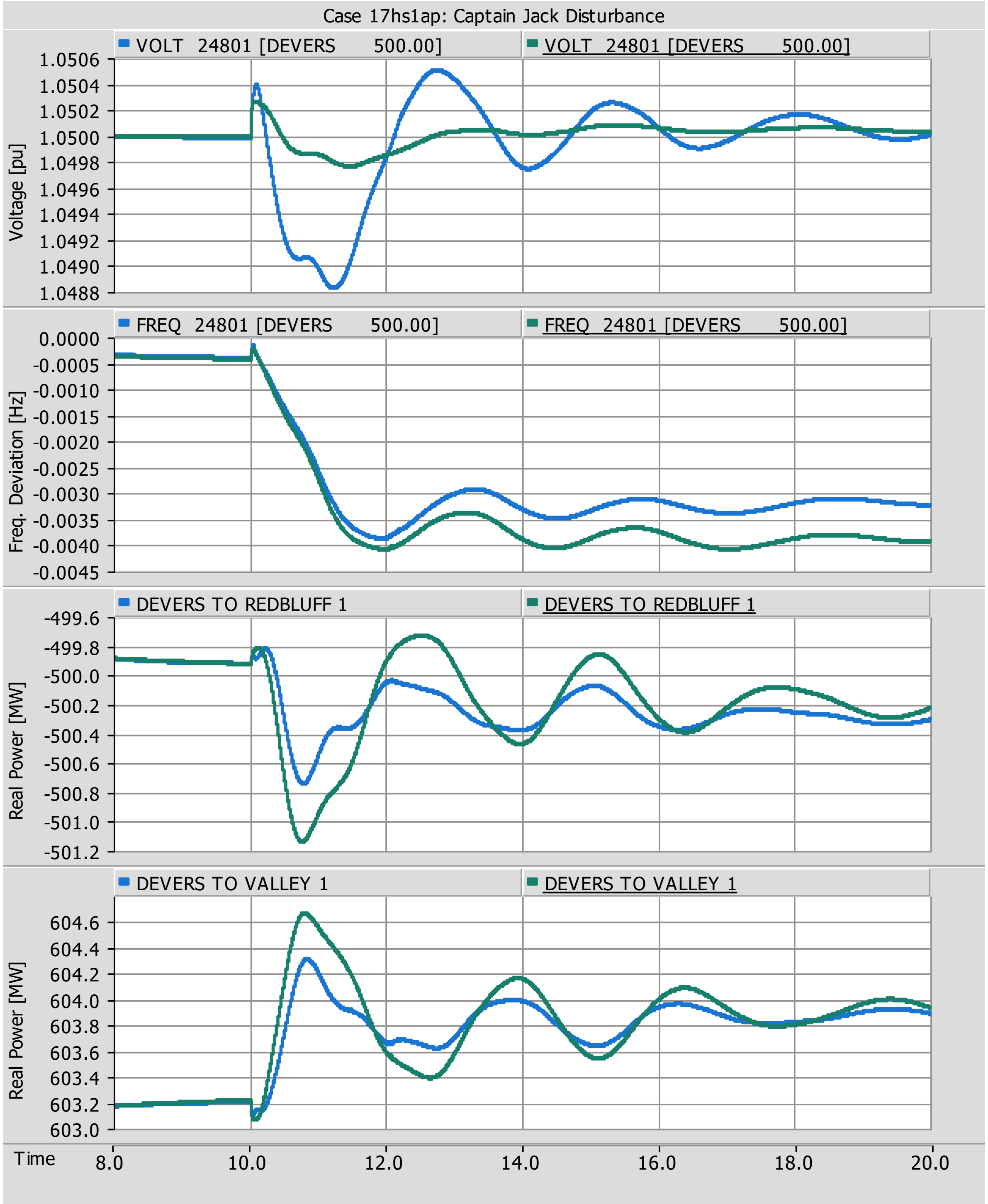

Figure 21: Results with and without the POD for the 'Captain Jack shunt capacitor' disturbance

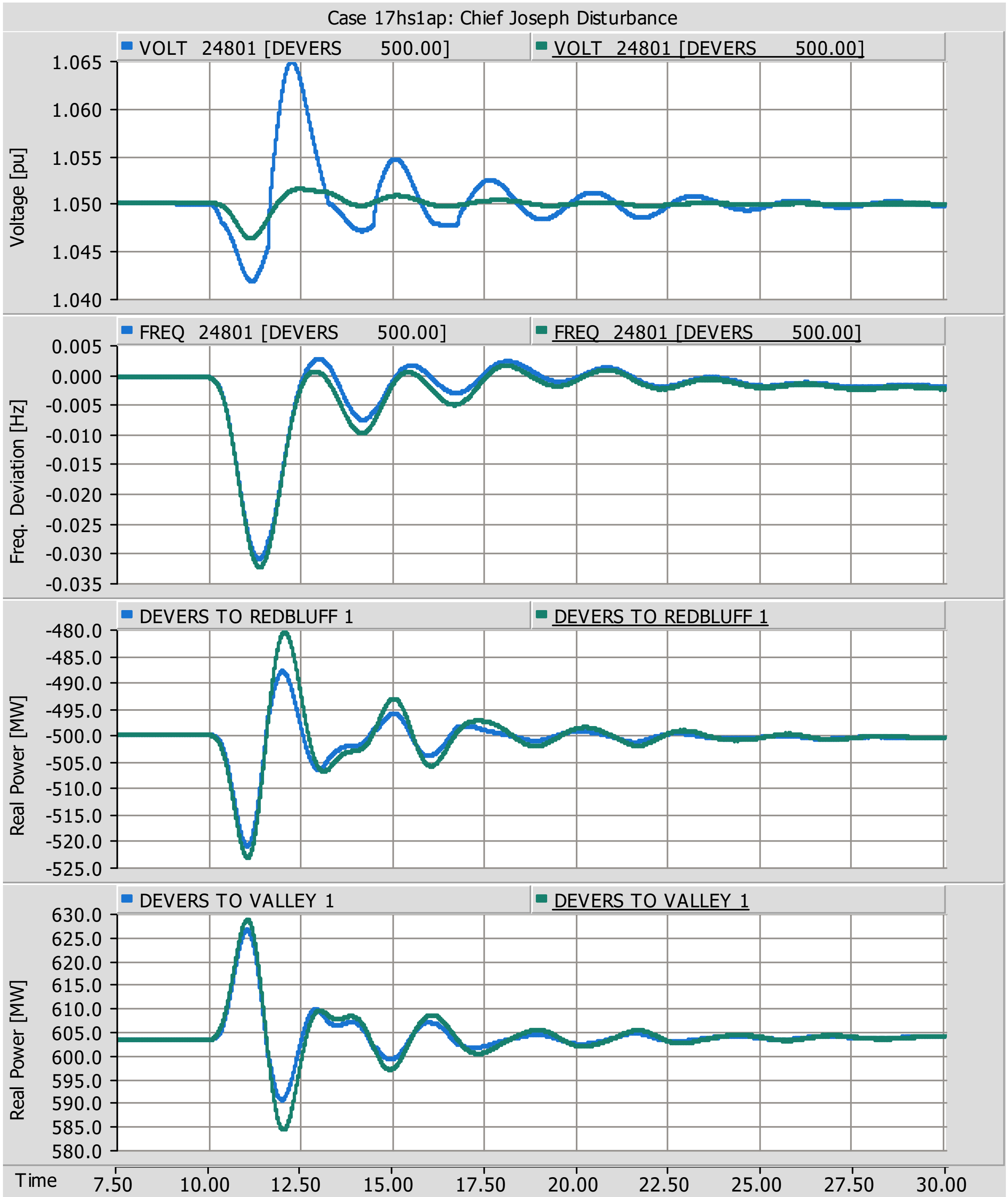

Figure 22: Results with and without the POD for the 'Chief Joseph brake insertion' disturbance

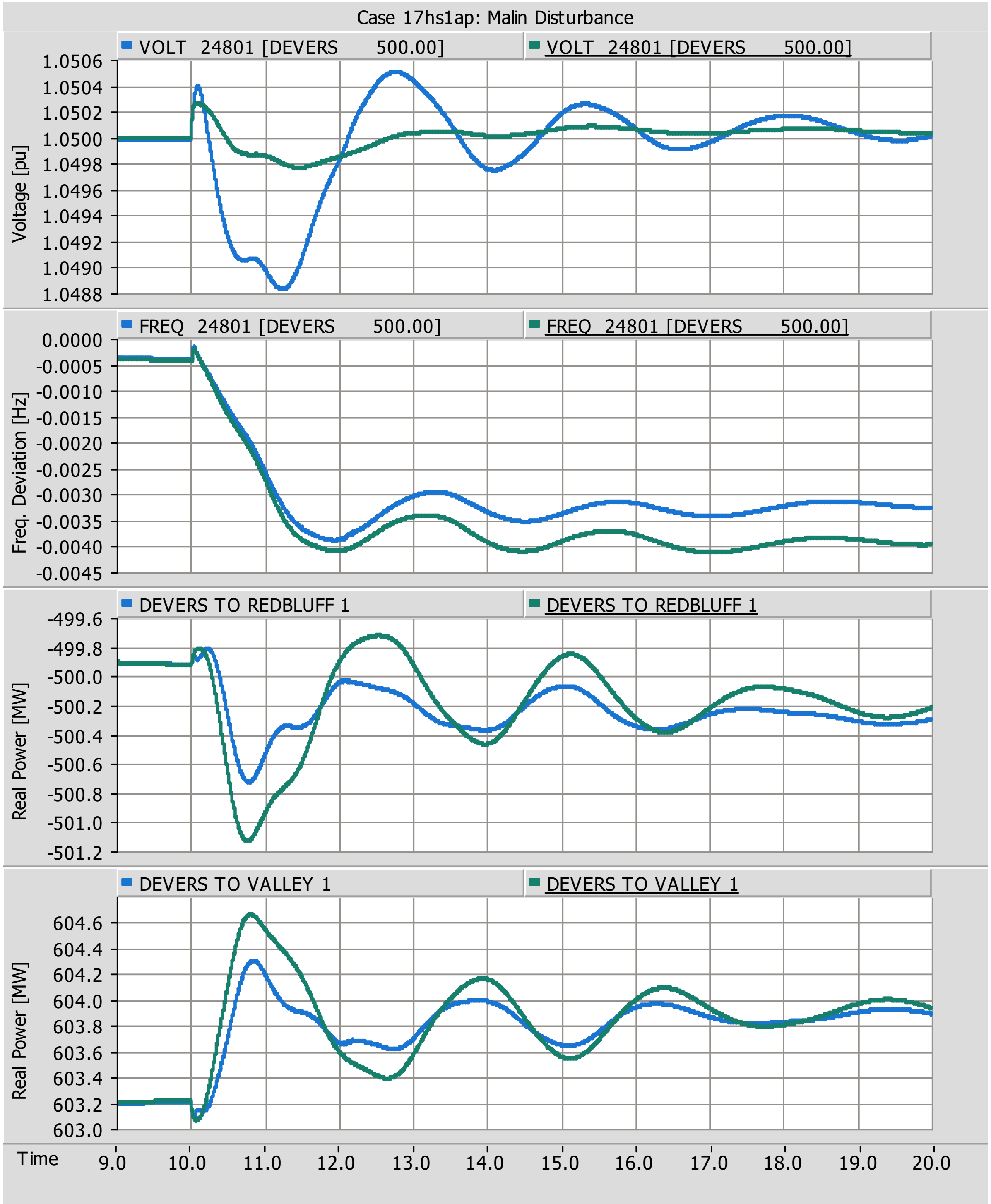

Figure 23: Results with and without the POD for the 'Malin shunt capacitor' disturbance

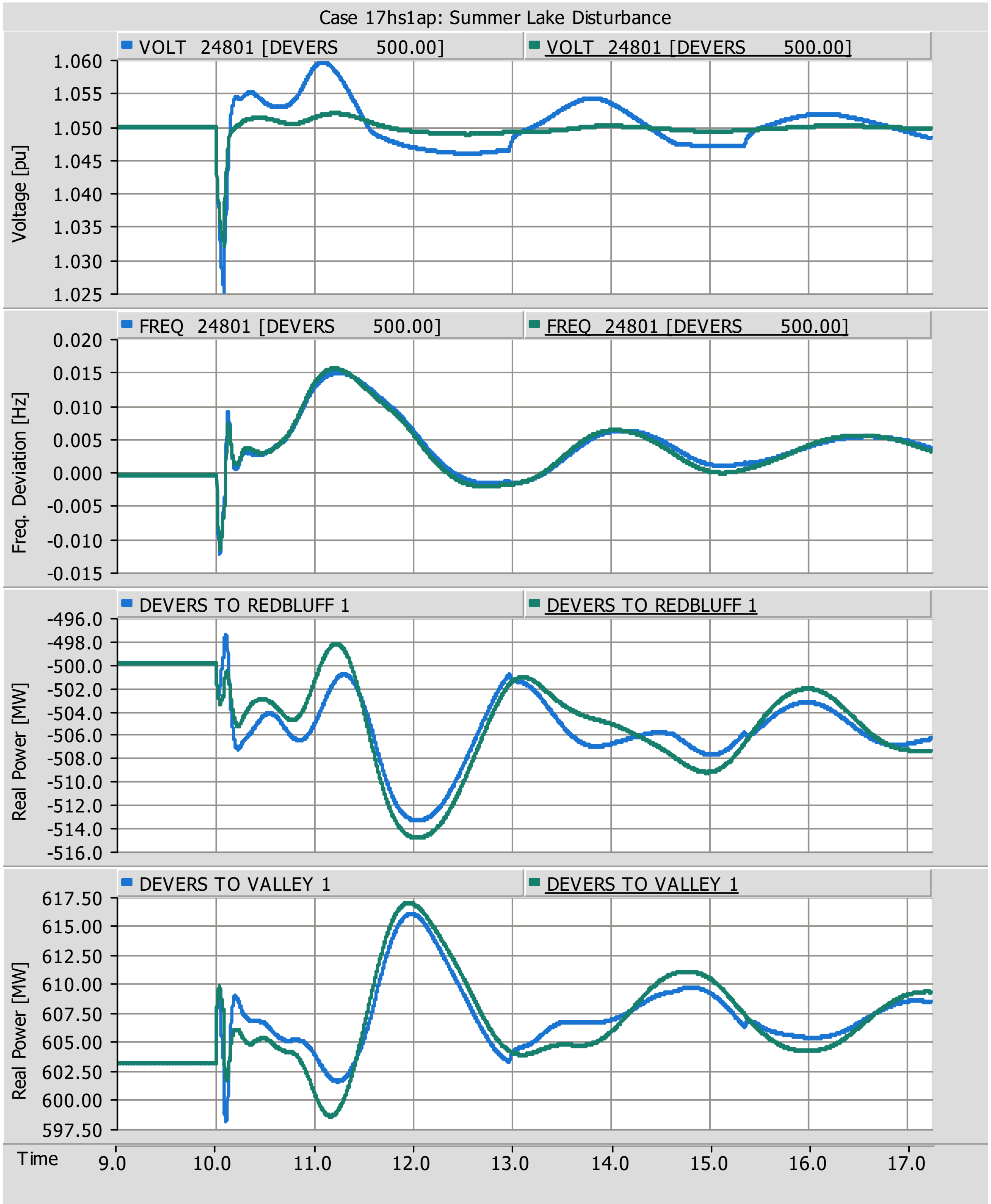

Figure 24: Results with and without the POD for the 'Summer Lake bus outage' disturbance

Figure 25 through Figure 29 show the same signals as above on a different time window that corresponds more closely to the time window selected for the Prony analysis.

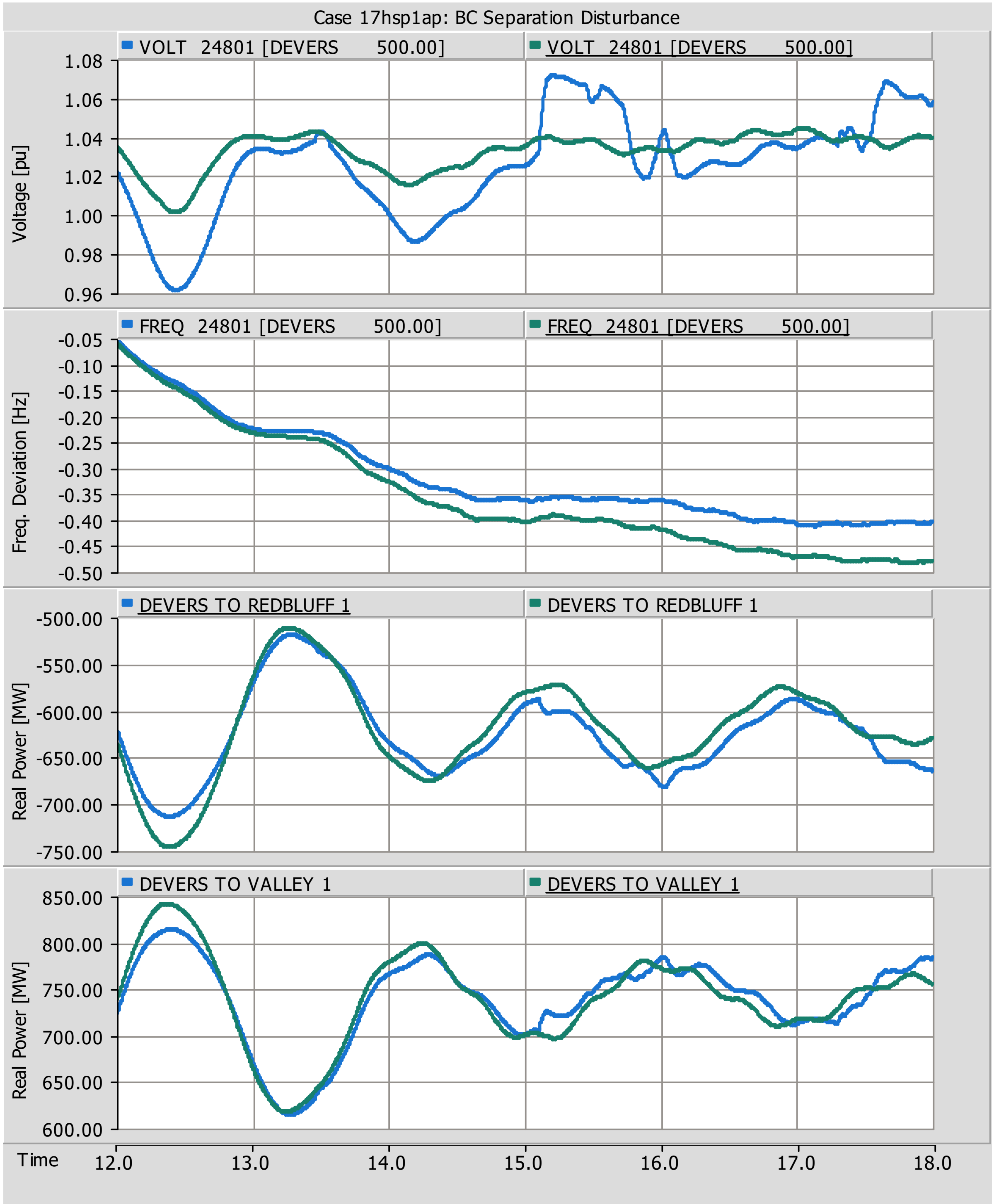

Figure 25: Results with and without the POD for the 'BC – NW Separation' disturbance

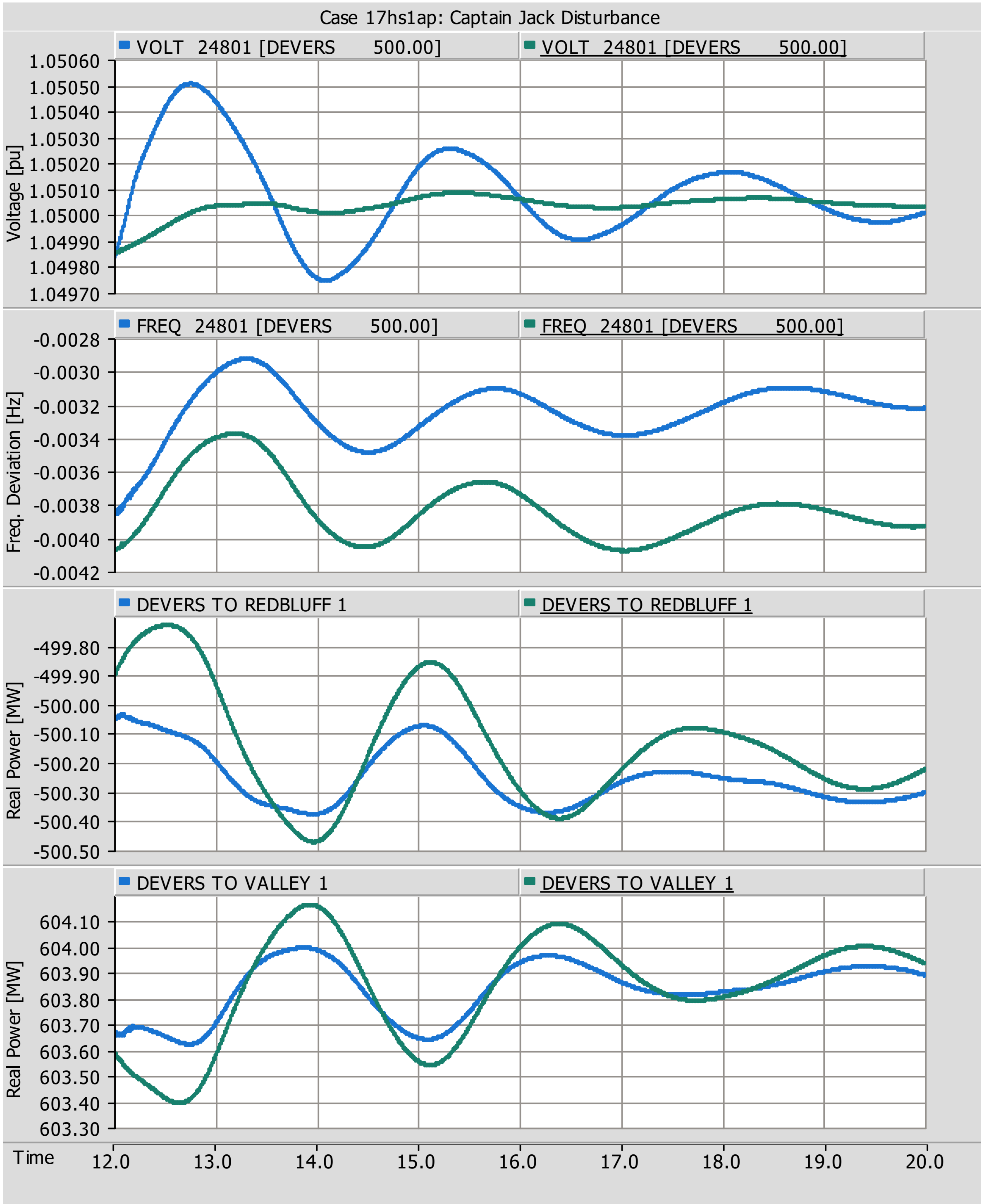

Figure 26: Results with and without the POD for the 'Captain Jack shunt capacitor' disturbance

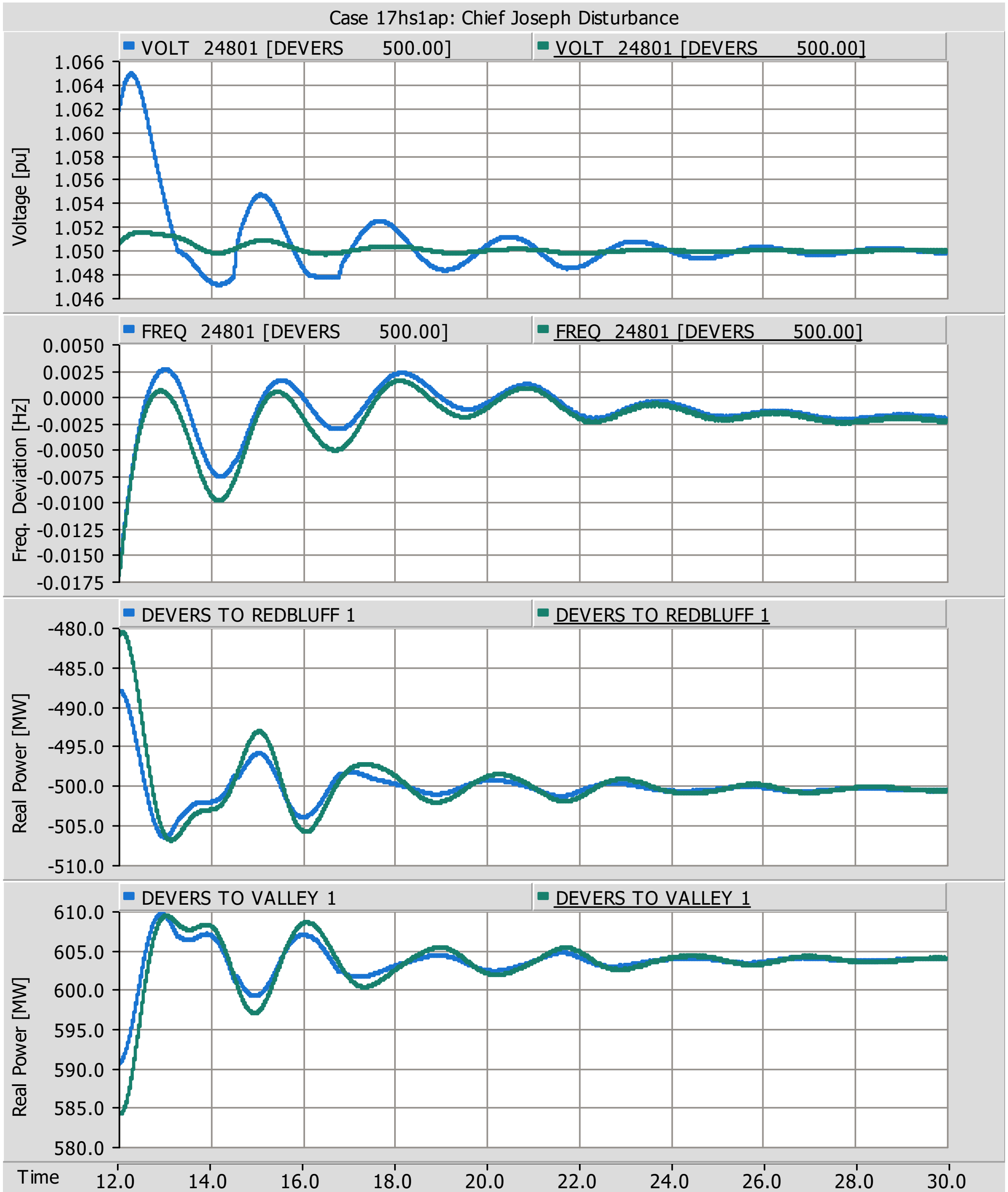

Figure 27: Results with and without the POD for the 'Chief Joseph brake insertion' disturbance

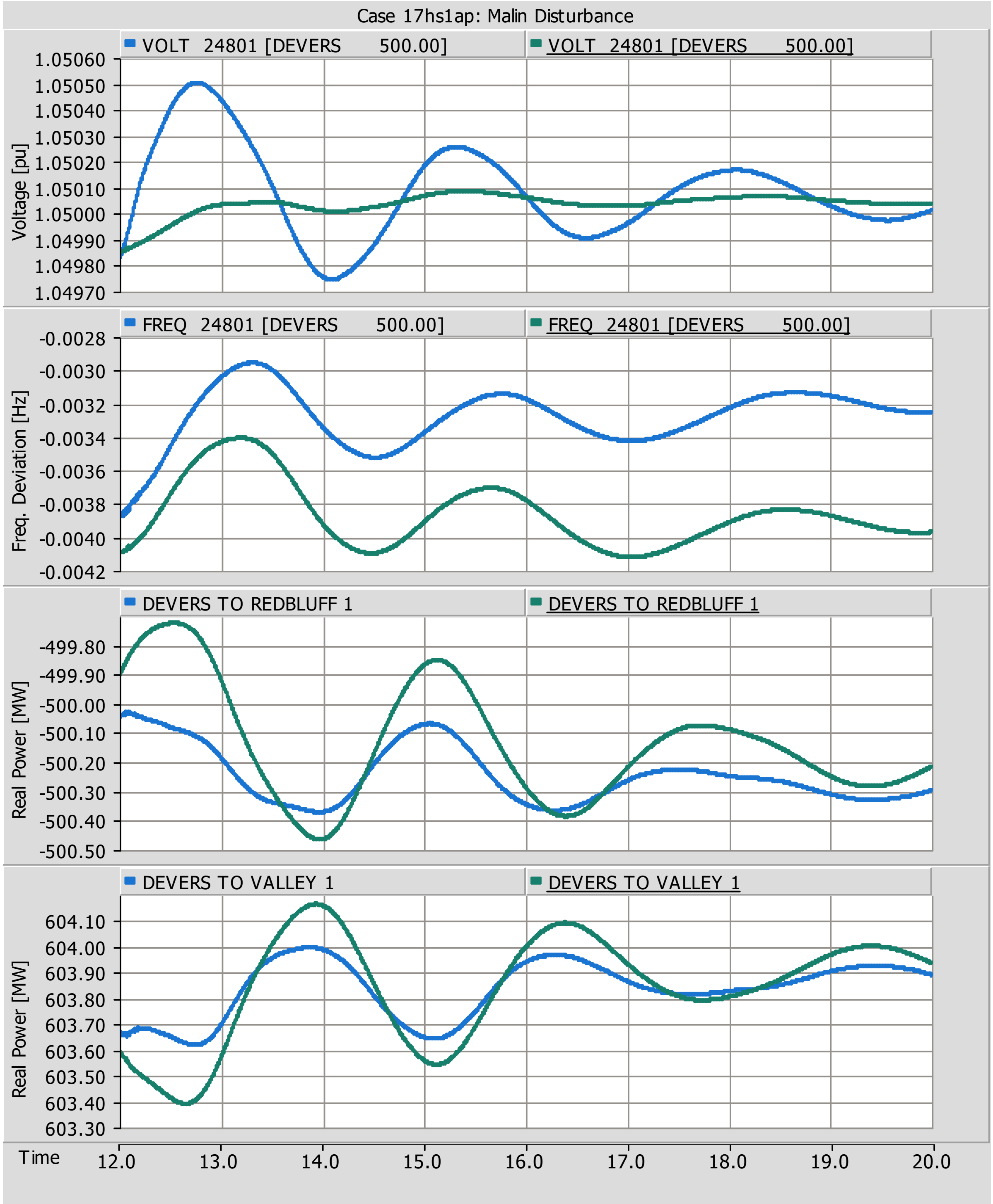

Figure 28: Results with and without the POD for the 'Malin shunt capacitor' disturbance

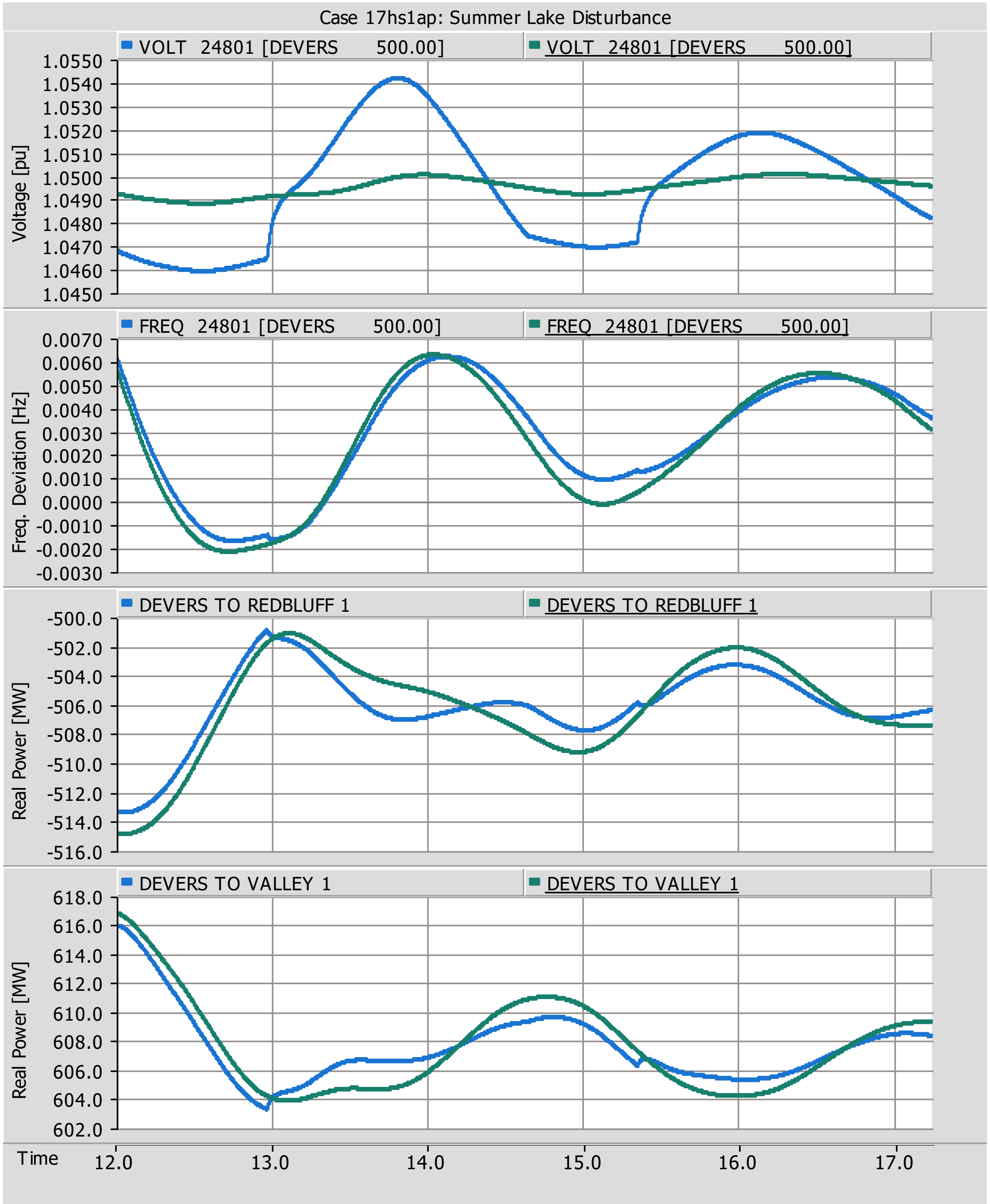

Figure 29: Results with and without the POD for the 'Summer Lake bus outage' disturbance

For this disturbance, multiple frequencies can be seen in the 'Devers-Redbluff' active power signal, which will reduce the accuracy of the results using the envelope decay method.

For the above disturbances, it can be seen that the POD was influencing the voltage at Devers, which increased the damping in some of the frequency and active power measurements. It is important to note that some of the oscillation magnitudes were reduced when the POD was enabled.

7.2 High Load Summer Season of 2018 Case

For this case, the POD parameters were tuned to improve the damping performance of the modes listed in the previous section and are listed in Table 6.

Table 6: POD parameters for case '18hs4ap'

CON	Name	Value
J+15	POD Gain	0.2000
J+16	PT1 time constant [s]	0.0497
J+17	POD Wash-out filter differential time constant [s]	0.2050
J+18	POD Wash-out filter lag time constant [s]	0.4974
J+19	POD Lead-Lag filter 1 lead time constant [s]	0.5927
J+20	POD Lead-Lag filter 1 lag time constant [s]	0.4173
J+21	POD Lead-Lag filter 2 lead time constant [s]	0.5927
J+22	POD Lead-Lag filter 2 lag time constant [s]	0.4173
J+23	POD Lead-Lag filter 3 lead time constant [s]	0.5927
J+24	POD Lead-Lag filter 3 lag time constant [s]	0.4173
J+25	POD limit [pu, based on nominal voltage of HV busbar]	0.05

The frequency response of the POD with the above parameters is shown in Figure 30.

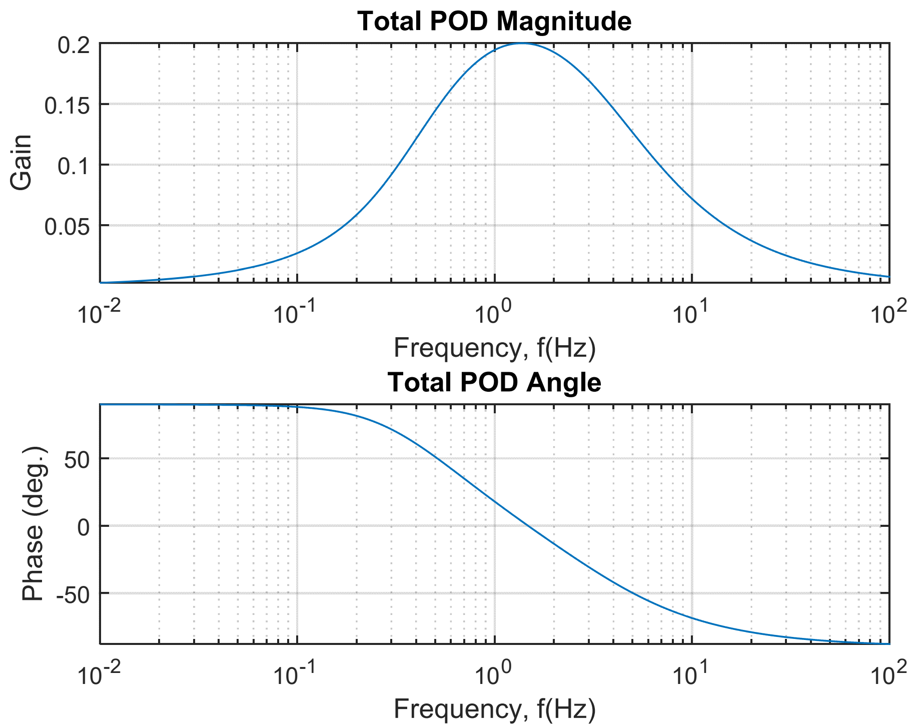

Figure 30: POD frequency response for case '18hs4ap'

7.2.1 Disturbances Located Close to Devers Substation

The identified modes at the Devers Substation for the disturbances located close to the SVC are shown in Table 77.

Table 7: Observable modes using Prony analysis methods for with and without the POD

Disturbance	Channel	Without POD		With POD	
		Damping	Frequency	Damping	Frequency
North Gila - Imperial Valley	P (Devers-Redbluff)	6%	0.52	6%	0.53
PDCI Block	P (Devers-Redbluff)	10%	0.54	10%	0.55
Palo Verde	P (Devers-Redbluff)	9%	0.74	9%	0.73
Devers - Valley	P (Devers-Redbluff)	7%	0.79	7%	0.78
PDCI Block	Frequency (Devers)	18%	0.45	13%	0.23
Devers - Valley	Frequency (Devers)	6%	0.42	8%	0.38
		9%	0.75	8%	0.78

In the above table, the envelope decay method and the Prony analysis method show similar results. The largest difference is in the 'PDCI Block' disturbance without the POD, where the Prony analysis method identified the dominant mode at 0.45 Hz. Therefore, a large difference in the damping ratios is possible. The results with the POD are also very similar to the results without the POD, excluding the PDCI Block disturbance without the POD. Figures 30 through 34 show the voltage and frequency at the 500-kV Devers bus and the active power transfers in the 'Devers-Redbluff' and 'Devers-Valley' circuits. The channels in blue are the results with the POD and the channels in green are the results without the POD.

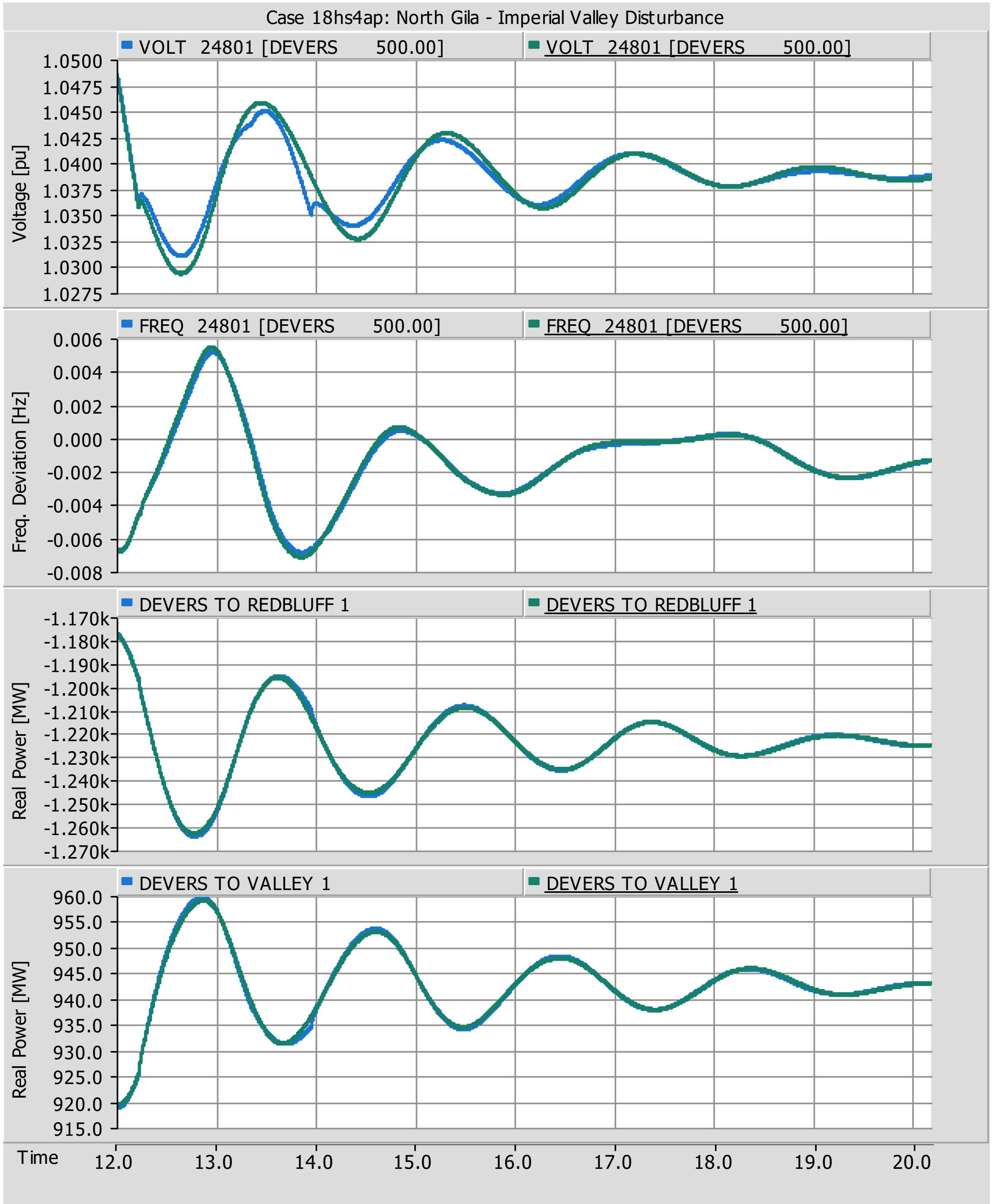

Figure 31: Results with and without the POD for the 'North Gila – Imperial Valley' disturbance

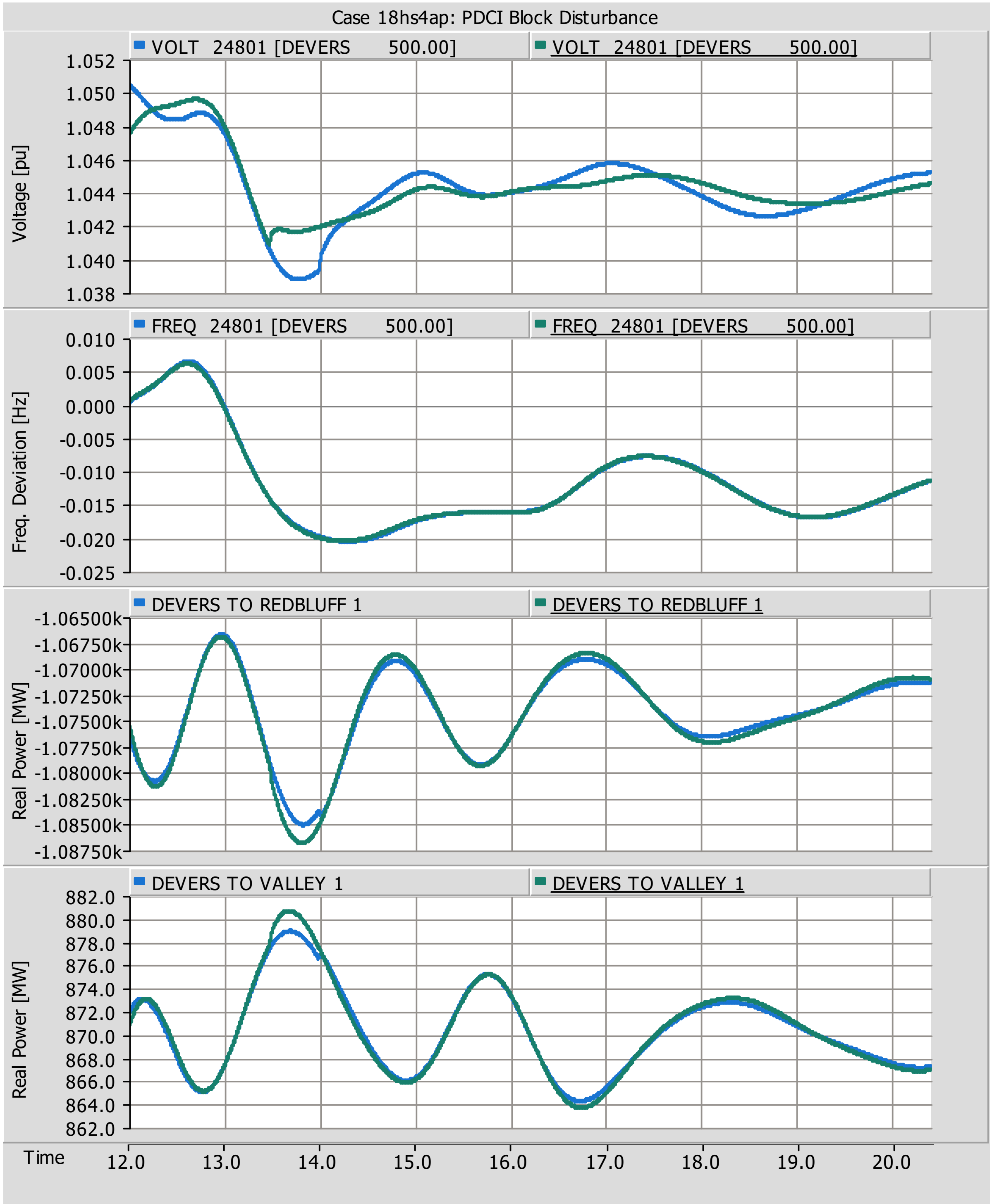

Figure 32: Results with and without the POD for the 'PDCI Block' disturbance

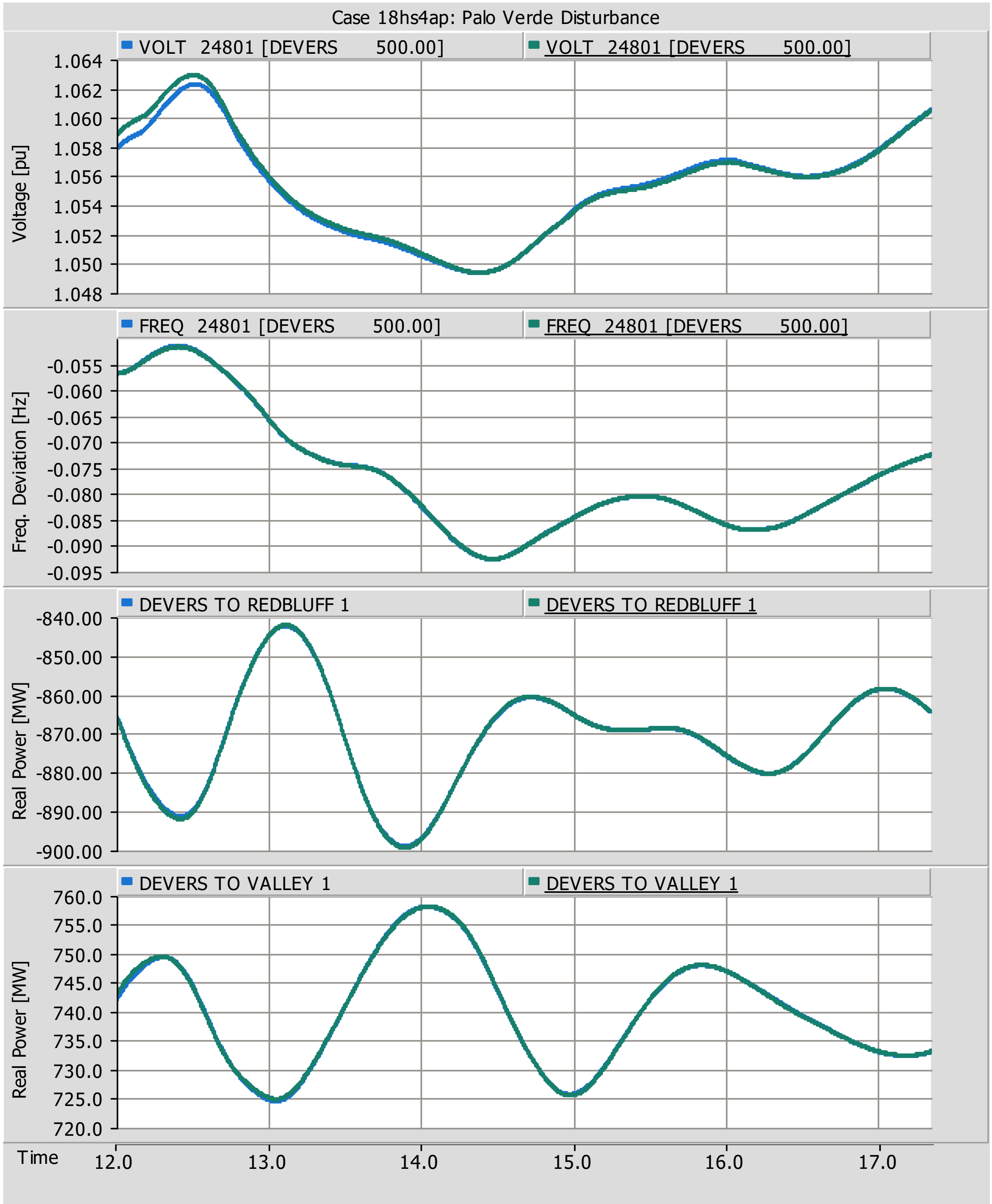

Figure 33: Results with and without the POD for the 'Palo Verde' disturbance

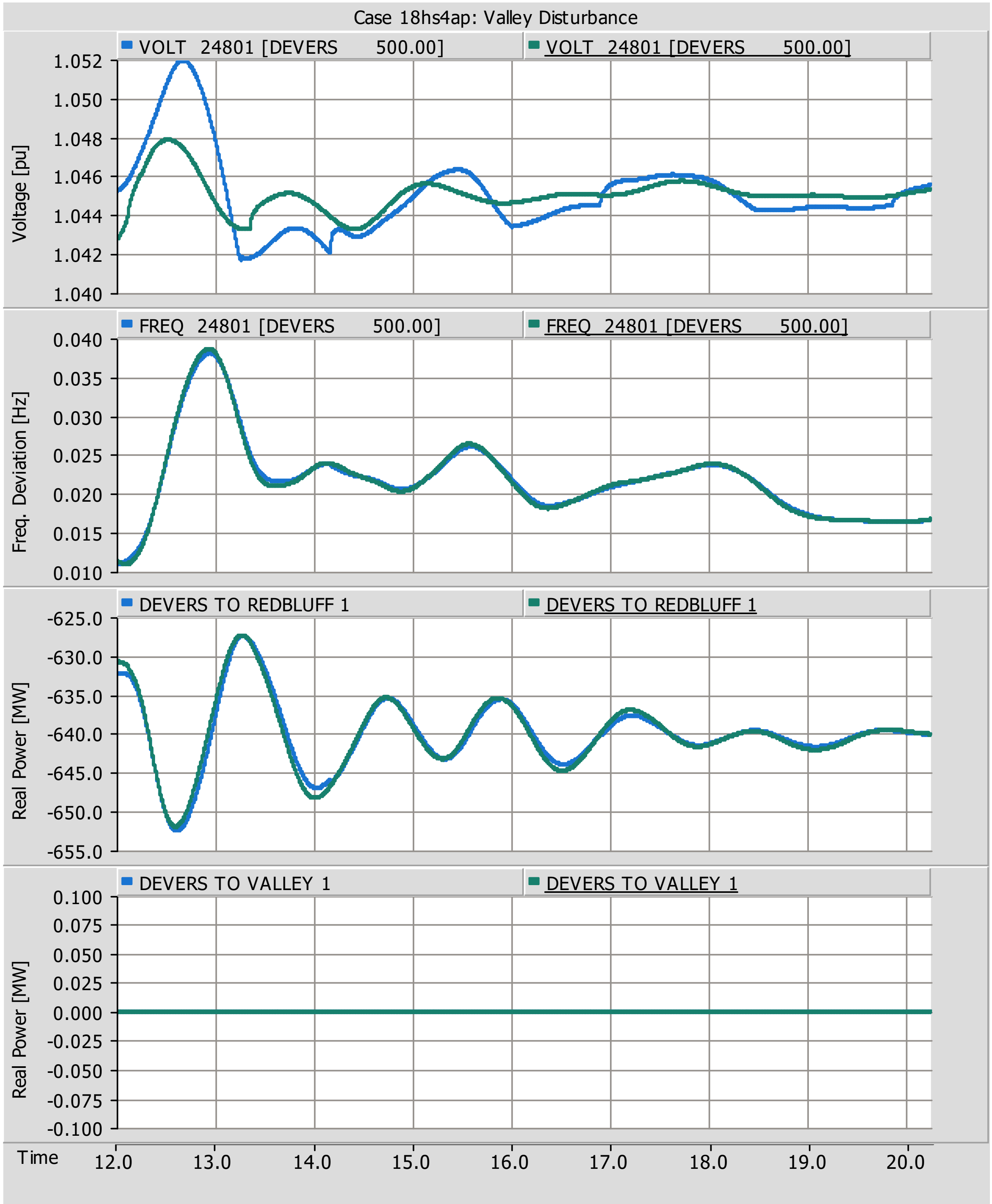

Figure 34: Results with and without the POD for the 'Devers – Valley' disturbance

For the majority of the above disturbances, the voltage at the SVC did not differ if the POD was enabled; therefore, the corresponding modes were not observable by the POD. For the 'Valley' disturbance in particular, the POD was able to influence the voltage, but the frequency and active power measurements were the same with and without the POD. Thus, these modes were uncontrollable.

7.2.2 Disturbances Located Far Away from the SVC at Devers

The identified modes at the Devers Substation for the disturbances located far from the SVC are shown in Table 8.

Table 8: Observable Modes Using Prony Analysis Methods With and Without the POD

Disturbance	Channel	Without POD		With POD	
		Damping	Frequency	Damping	Frequency
BC - NW Separation	P (Devers-Redbluff)	12%	0.41	13%	0.40
Captain Jack – Grizzly Series Cap	P (Devers-Redbluff)	18%	0.69	13%	0.68
Chief Joseph Brake Insertion	P (Devers-Redbluff)	9%	0.35	12%	0.36
Malin – Round Mountain	P (Devers-Redbluff)	14%	0.39	15%	0.41
Summer Lake Bus Outage	P (Devers-Redbluff)	12%	0.41	11%	0.54
Summer Lake - Ponderosa	P (Devers-Redbluff)	22%	0.38	20%	0.39
BC – NW Separation	Frequency (Devers)	10%	0.41	9%	0.41
Chief Joseph Brake Insertion	Frequency (Devers)	19%	0.36	12%	0.42
Malin – Round Mountain	Frequency (Devers)	16%	0.42	17%	0.42
Summer Lake Bus Outage	Frequency (Devers)	15%	0.46	16%	0.46
Summer Lake - Pondrosa	Frequency (Devers)	17%	0.64	15%	0.64

Figures 35 through 40 show the voltage and frequency at the 500-kV Devers bus and the active power transfers in the 'Devers-Redbluff' and 'Devers-Valley' circuits. The channels in blue are the results with the POD and the channels in green are the results without the POD.

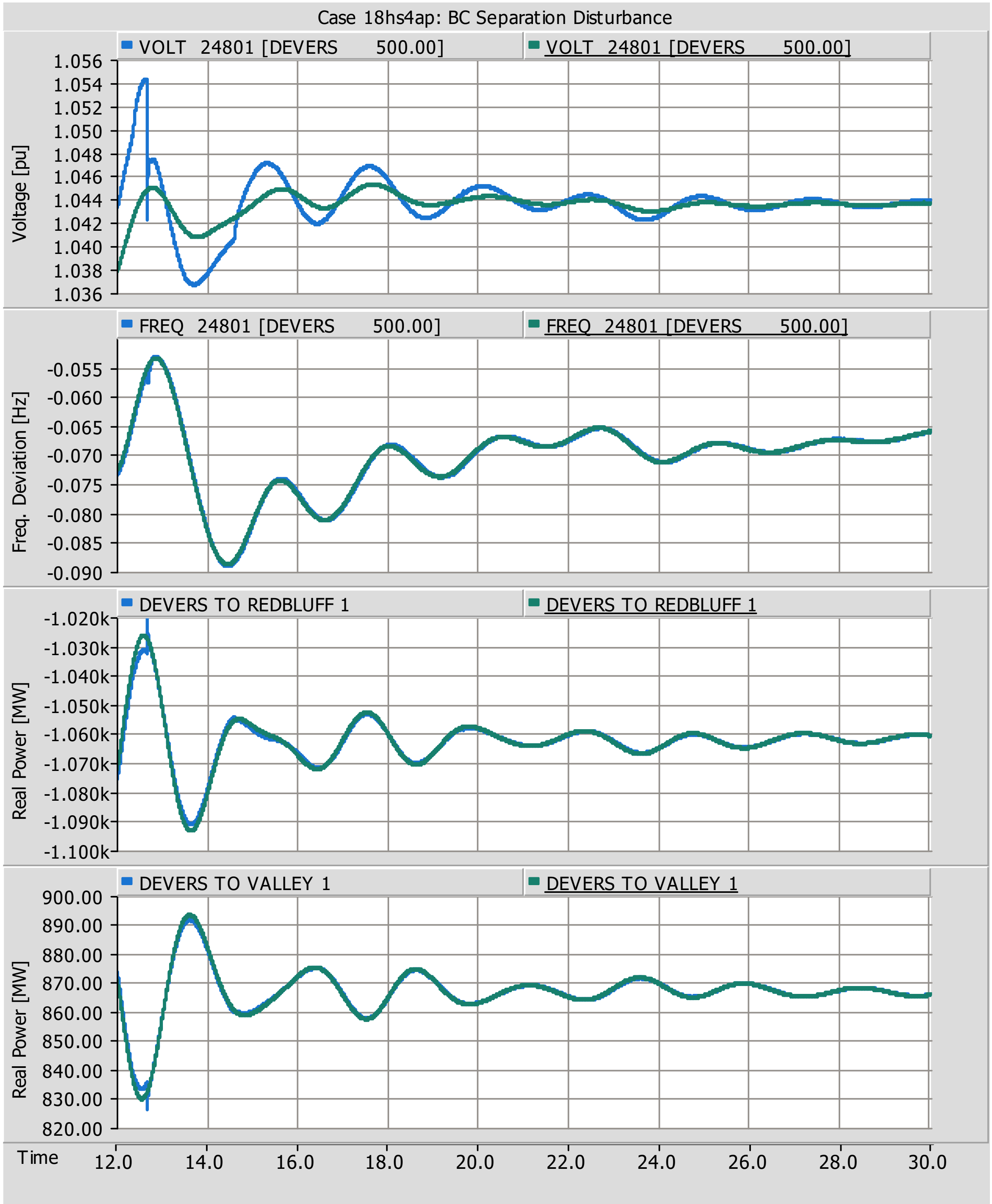

Figure 35: Results with and without the POD for the 'BC – NW Separation' disturbance

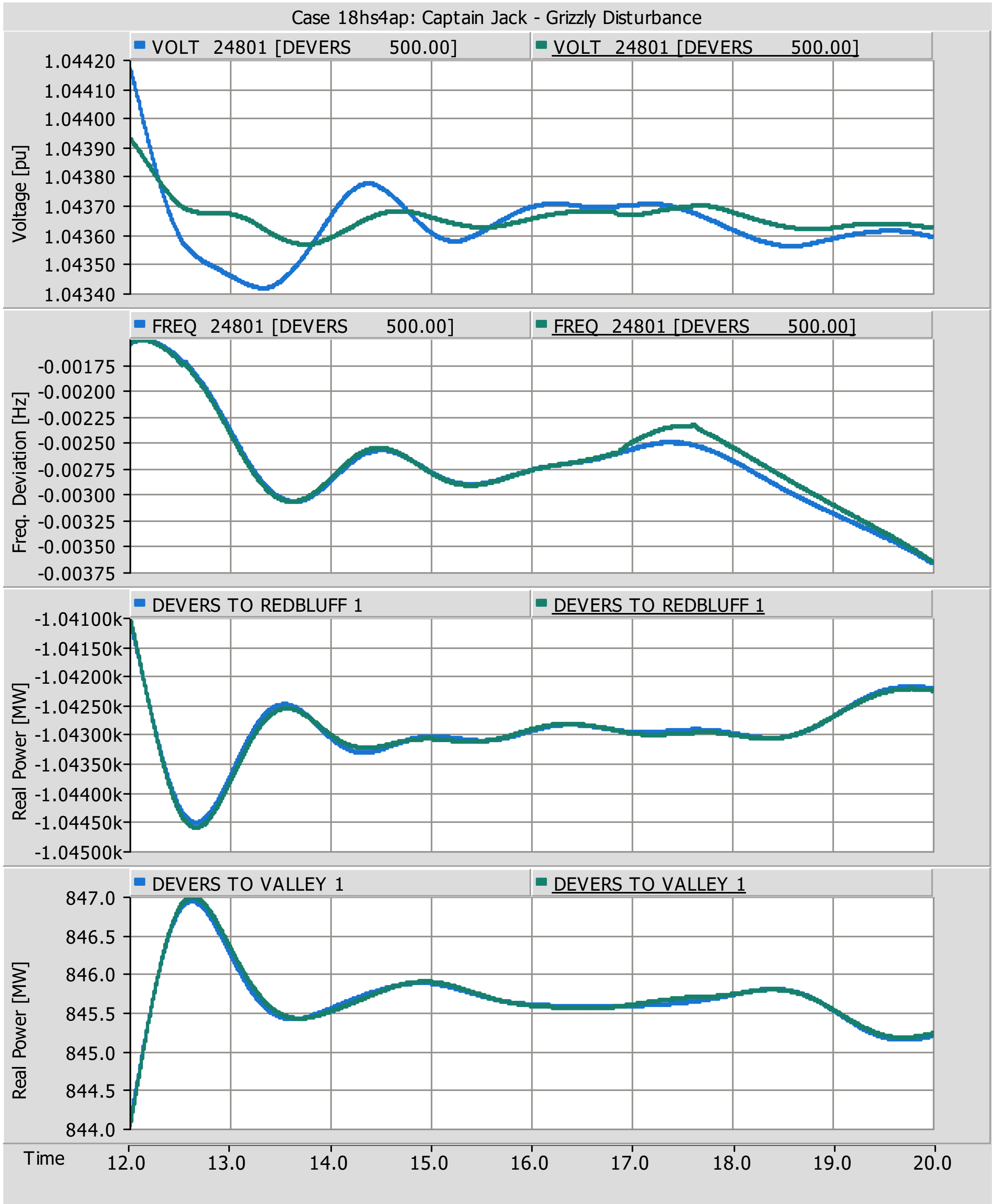

Figure 36: Results with and without the POD for the 'Captain Jack – Grizzly series capacitor' disturbance

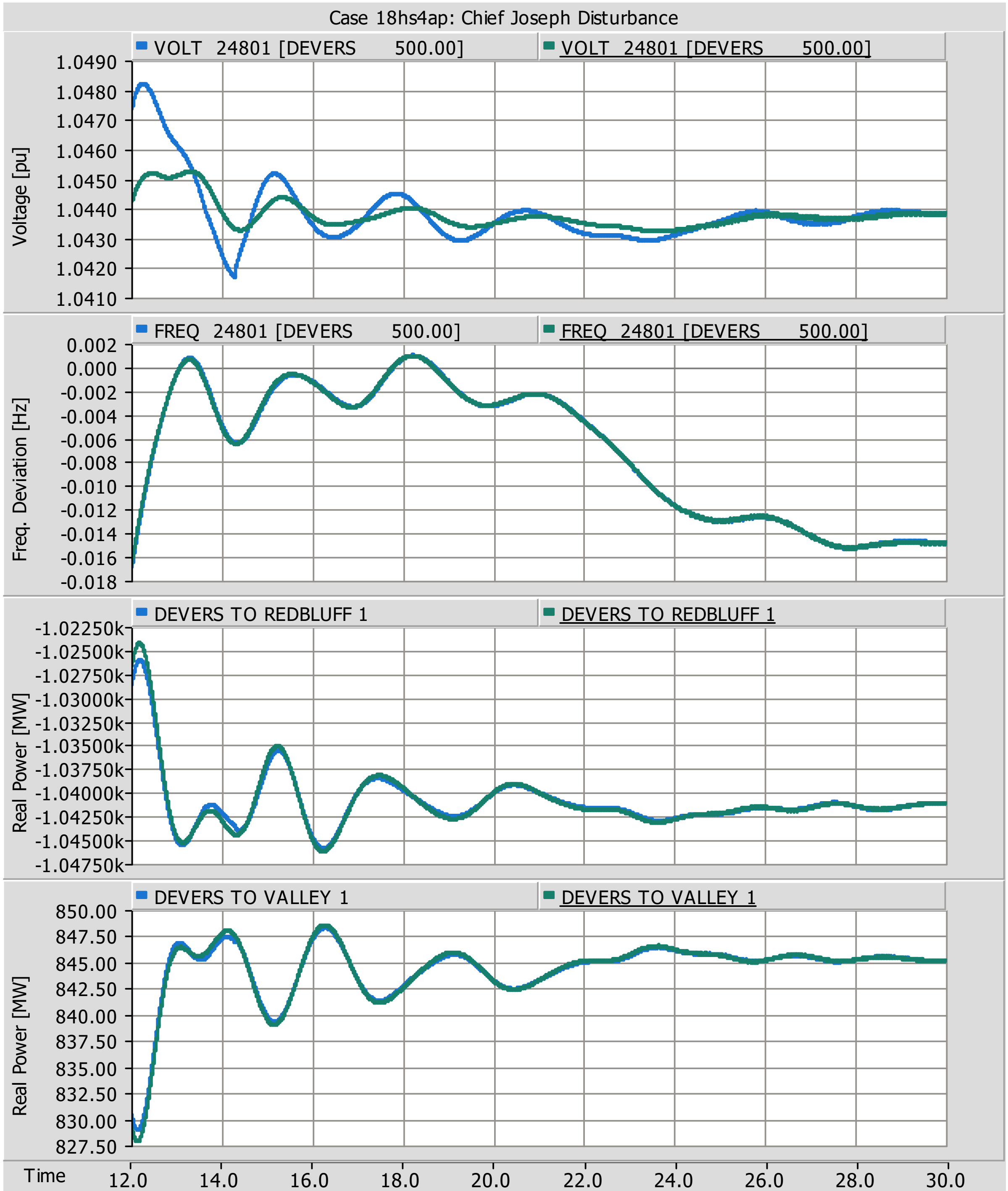

Figure 37: Results with and without the POD for the 'Chief Joseph brake insertion' disturbance

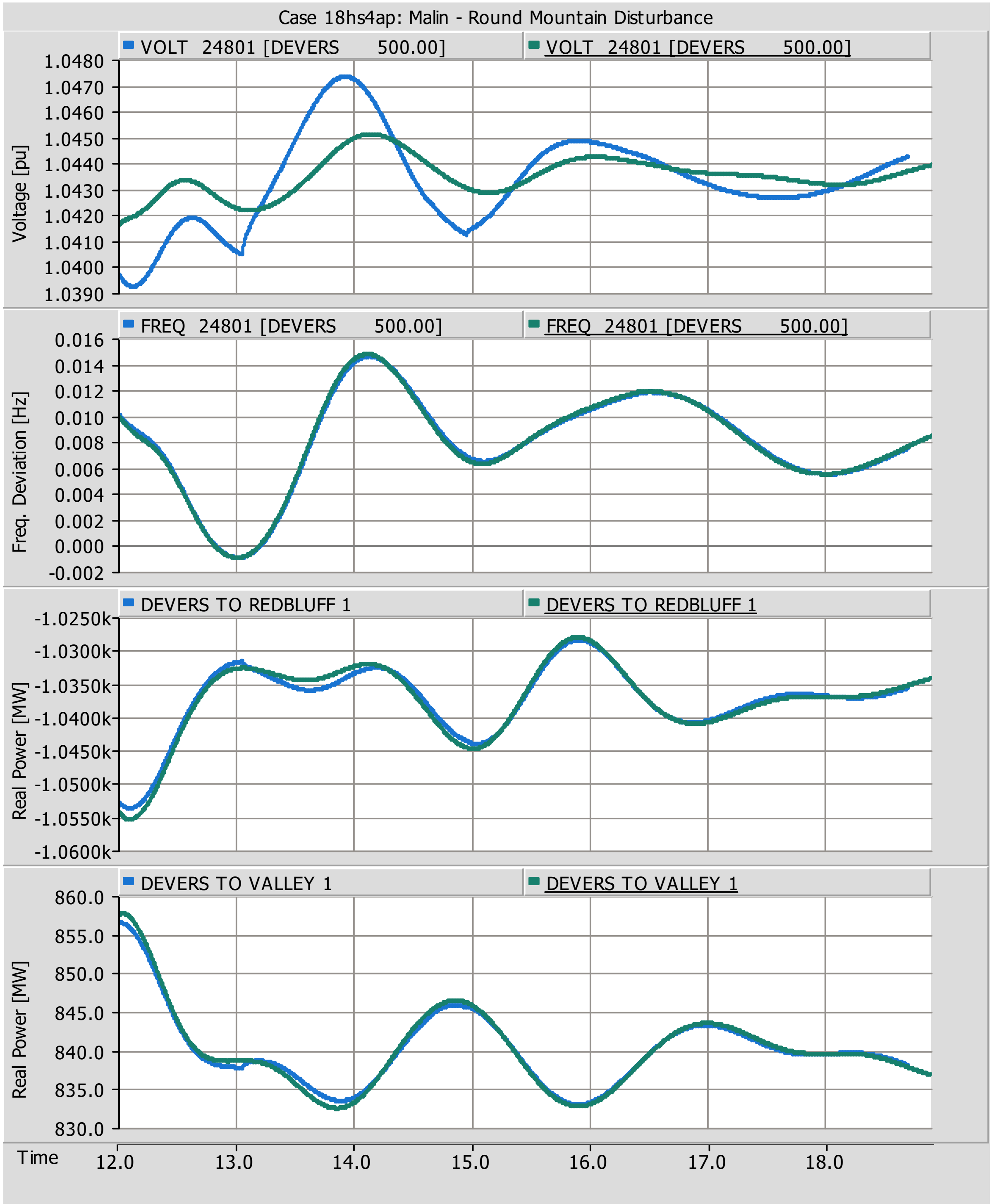

Figure 38: Results with and without the POD for the 'Malin – Round Mountain' disturbance

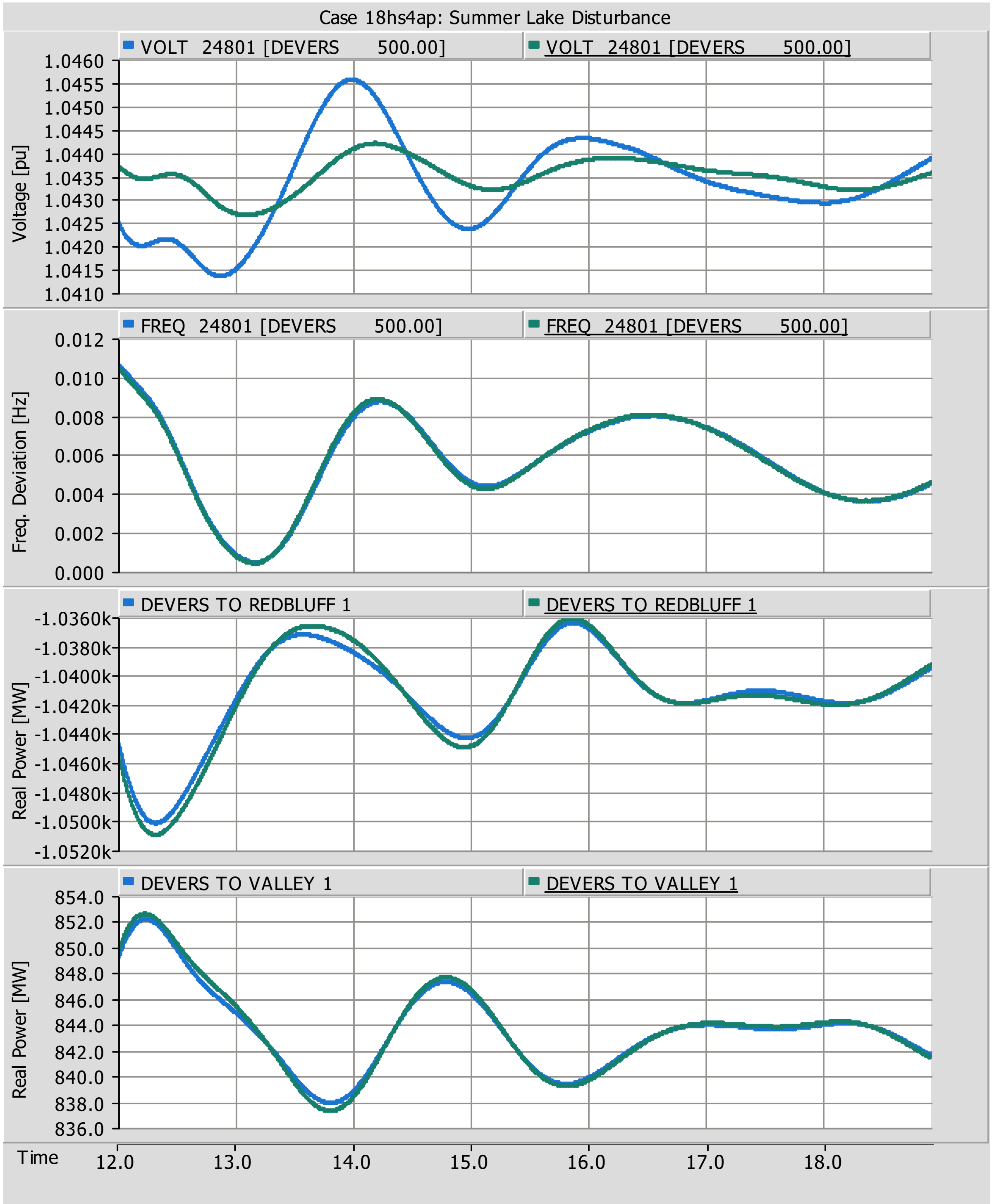

Figure 39: Results with and without the POD for the 'Summer Lake bus outage' disturbance

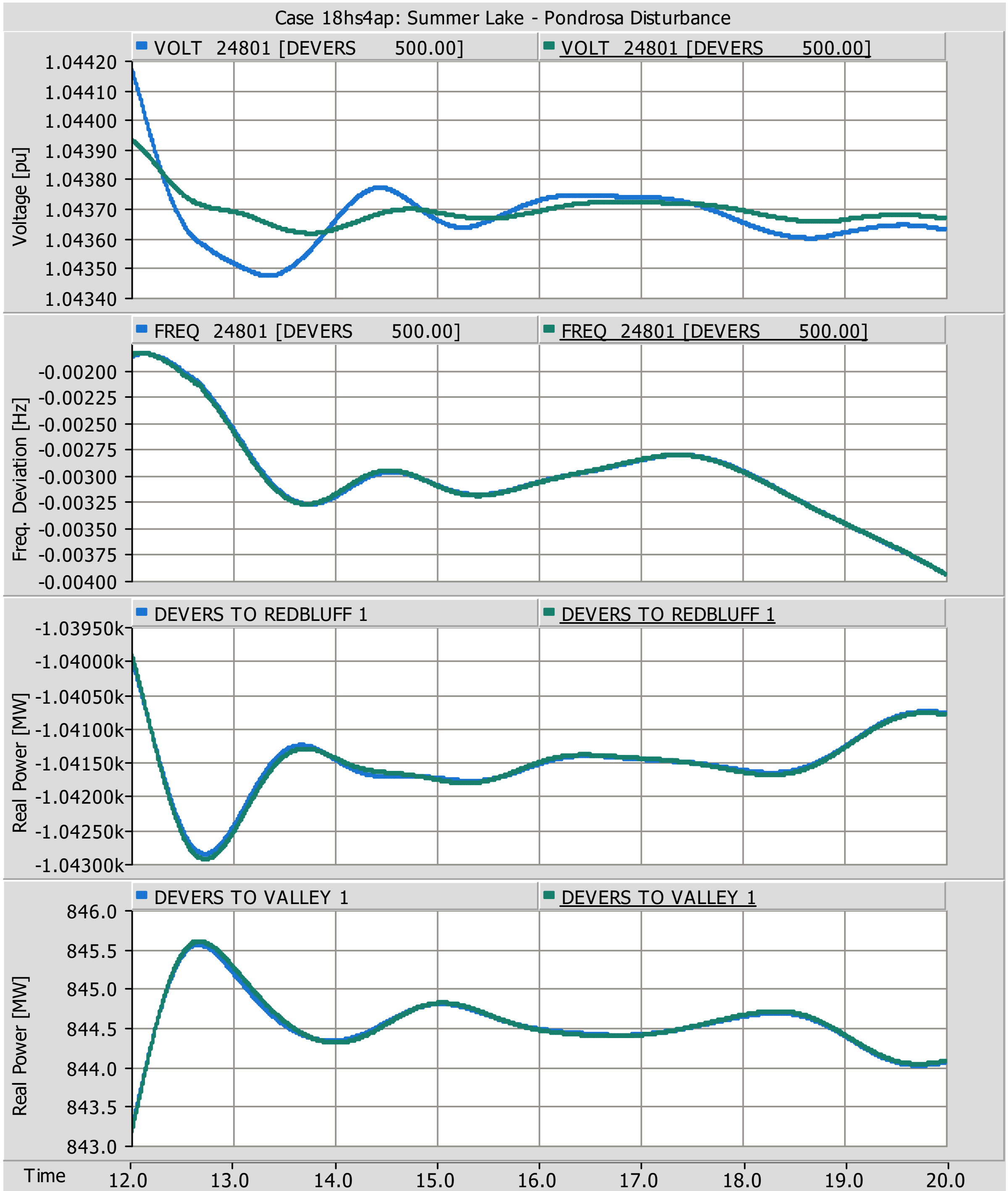

Figure 40: Results with and without the POD for the ‘Summer Lake – Pondrosa’ disturbance

In the above disturbances, the modes were observed by the POD at Devers, but they were uncontrollable. This agrees with the results in Table 8, where the damping of the modes with and without the POD are similar.

7.3 High Load Winter Season of 2021 '21hw1ap'

For this case, the POD parameters were tuned to improve the damping performance of the modes identified in the previous section, and their new values are listed below in Table 9.

Table 9: POD parameters for case '21hw1ap'

CON	Name	Value
J+15	POD Gain	0.2000
J+16	PT1 time constant [s]	0.0497
J+17	POD Wash-out filter differential time constant [s]	0.2050
J+18	POD Wash-out filter lag time constant [s]	0.4974
J+19	POD Lead-Lag filter 1 lead time constant [s]	0.5927
J+20	POD Lead-Lag filter 1 lag time constant [s]	0.4173
J+21	POD Lead-Lag filter 2 lead time constant [s]	0.5927
J+22	POD Lead-Lag filter 2 lag time constant [s]	0.4173
J+23	POD Lead-Lag filter 3 lead time constant [s]	0.5927
J+24	POD Lead-Lag filter 3 lag time constant [s]	0.4173
J+25	POD limit [pu, based on nominal voltage of HV busbar]	0.05

The frequency response of the POD with the above parameters is shown in Figure 41.

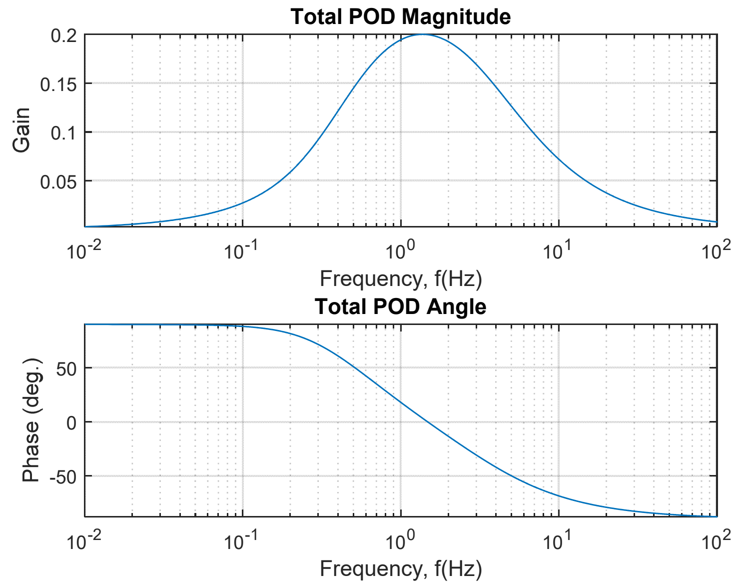

Figure 41: POD frequency response for case '21hw1ap'

7.3.1 Disturbances Located Close to Devers Substation

The identified modes for the disturbances located close to the SVC at Devers are shown in Table 10.

Table 10: Observable modes using Prony analysis methods for with and without the POD

Disturbance	Channel	Without POD		With POD	
		Damping	Frequency	Damping	Frequency
		Prony	Prony	Prony	Prony
Lugo – Mira Loma	P (Devers-Redbluff)	9%	0.80	15%	0.81
Palo Verde	P (Devers-Redbluff)	5%	0.33	16%	0.52
Devers - Valley	P (Devers-Redbluff)	13%	0.70	10%	0.78
Lugo – Mira Loma	Frequency (Devers)	10%	1.17	8%	1.13
Palo Verde	Frequency (Devers)	10%	0.42	5%	0.36
		11%	0.86	14%	0.98
Devers - Valley	Frequency (Devers)	6%	0.44	2%	0.48
		8%	0.75	3%	0.84
		3%	1.95	4%	1.94

In the above table, the results obtained from the envelope decay method match with the results obtained from the Prony analysis method. Figures 42 through 44 show the voltage and frequency at the 500-kV Devers bus and the active power transfers in the 'Devers-Redbluff' and 'Devers-Valley' circuits. The channels in blue are the results with the POD and the channels in green are the results without the POD.

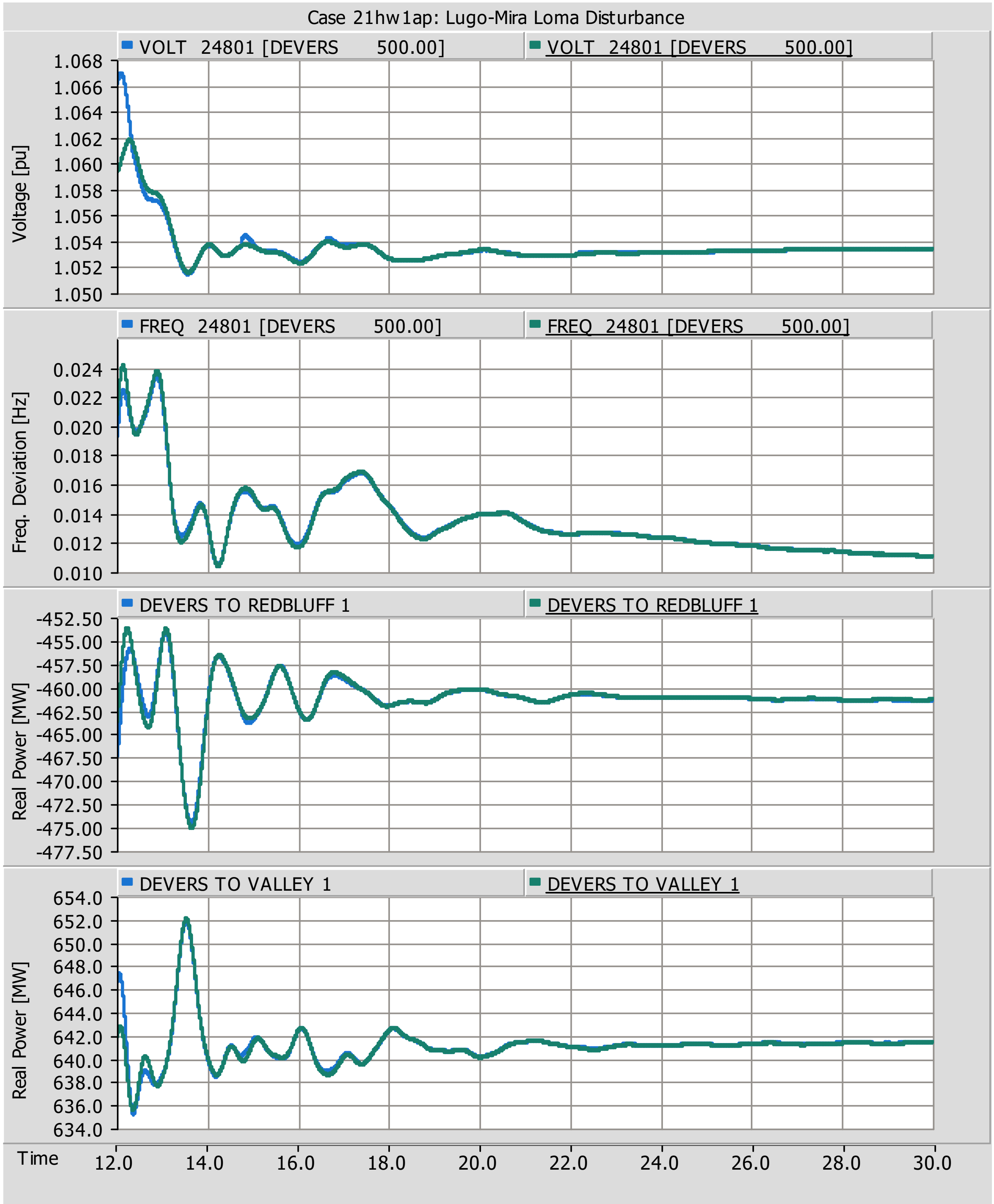

Figure 42: Results with and without the POD for the 'Lugo - Mira Loma' disturbance

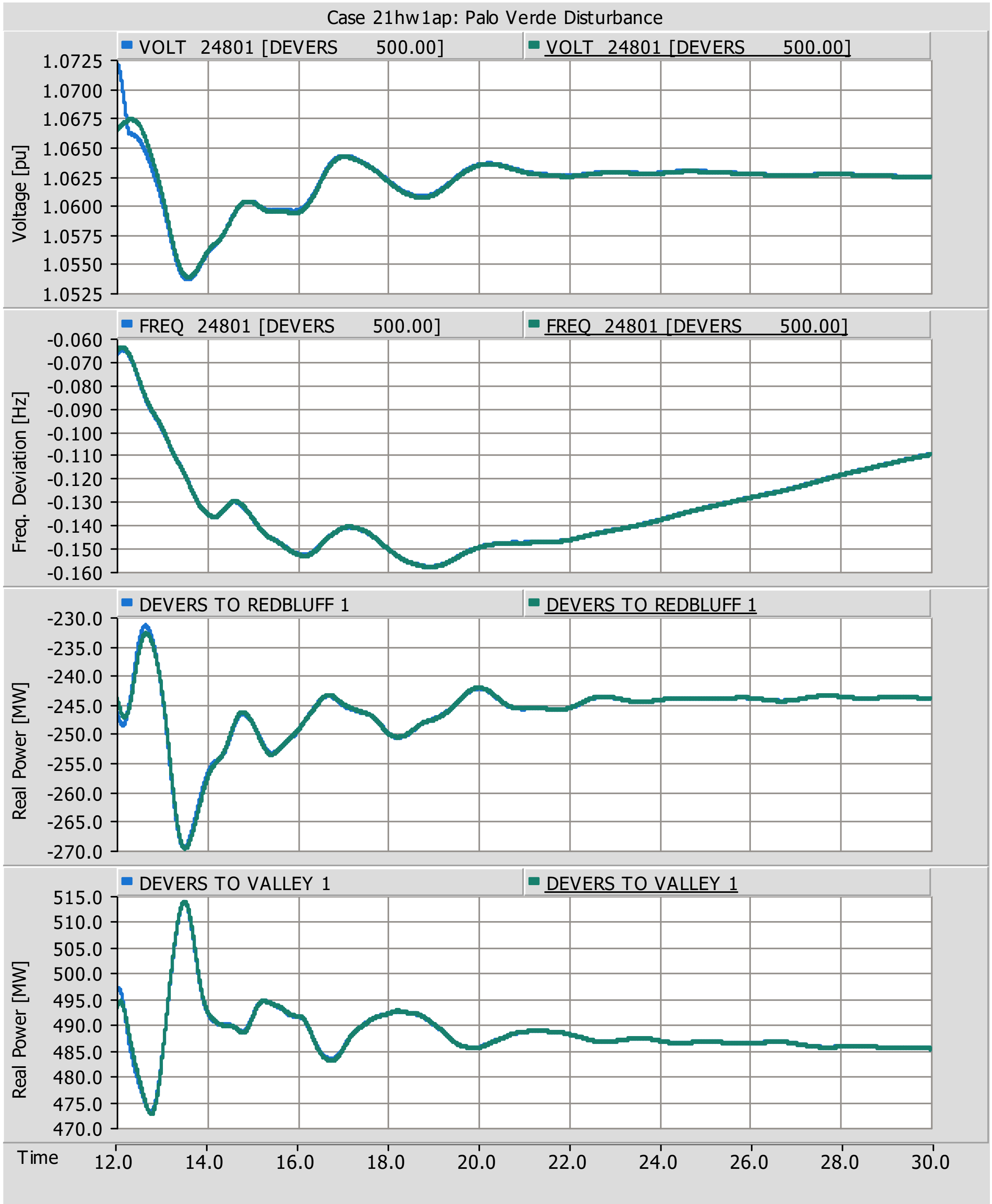

Figure 43: Results with and without the POD for the 'Palo Verde' disturbance

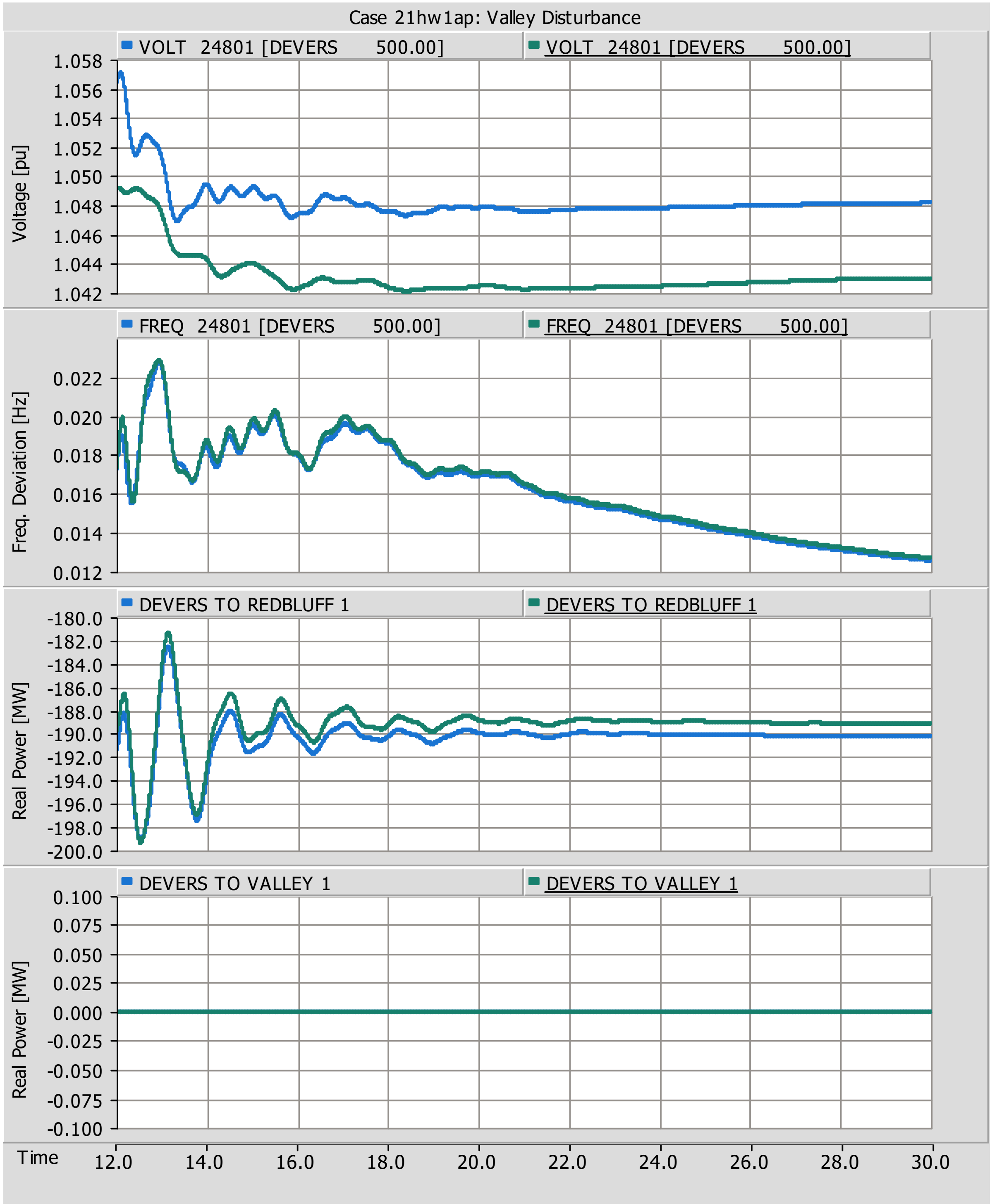

Figure 44: Results with and without the POD for the 'Devers – Valley' disturbance

In the above disturbances, the voltage at the SVC was similar with and without the POD. This means that the modes could not be observed by the SVC at Devers. This agrees with the results in Table 10 in that the damping was very similar before and after the POD was enabled.

7.3.2 Disturbances Located Far Away from Devers Substation

The identified modes for the disturbances located away from Devers substation are shown in Table 11.

Table 11: Observable modes using Prony analysis method for with and without the POD

Disturbance	Channel	Without POD		With POD	
		Damping	Frequency	Damping	Frequency
BC - NW Separation without FACRI	P (Devers-Redbluff)	2%	0.75	2%	0.74
		13%	0.38	13%	0.38
		-6%	0.67	-6%	0.67
BC - NW Separation with FACRI*	P (Devers-Redbluff)	-6%	0.71	-4%	0.63
		9%	0.37	10%	0.46
Captain Jack Shunt Capacitor	P (Devers-Redbluff)	10%	0.60	12%	0.45
Malin Shunt Capacitor	P (Devers-Redbluff)	13%	0.43	12%	0.43
Malin – Round Mountain	P (Devers-Redbluff)	9%	0.58	9%	0.58
		11%	0.89	8%	0.91
Summer Lake Bus Outage	P (Devers-Redbluff)	16%	0.36	16%	0.36
		11%	0.56	14%	0.57
		17%	0.70	14%	0.75
BC - NW Separation without FACRI	Frequency (Devers)	26%	0.34	18%	0.30
		-1%	0.74	-1%	0.70
				9%	0.77
BC - NW Separation with FACRI*	Frequency (Devers)	-2%	0.68	-2%	0.69
		4%	0.78	9%	0.78

* The FACRI scheme was activated for this disturbance

Figures 45 through 50 show the voltage and frequency at the 500-kV Devers bus and the active power transfers in the 'Devers-Redbluff' and 'Devers-Valley' circuits. The channels in blue are the results with the POD and the channels in green are the results without the POD.

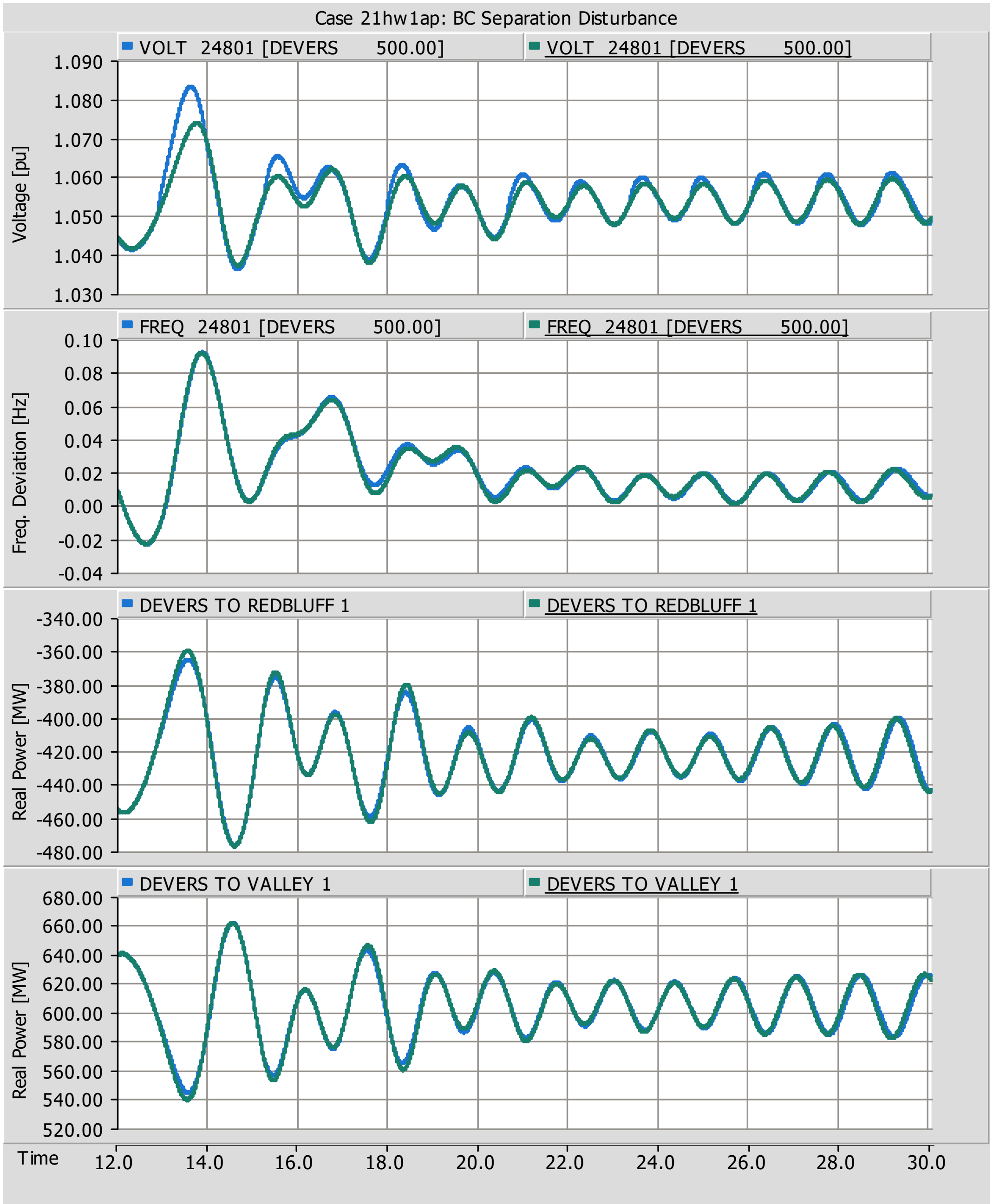

Figure 45: Results with and without the POD for the 'BC – NW Separation' disturbance without the FACRI RAS scheme

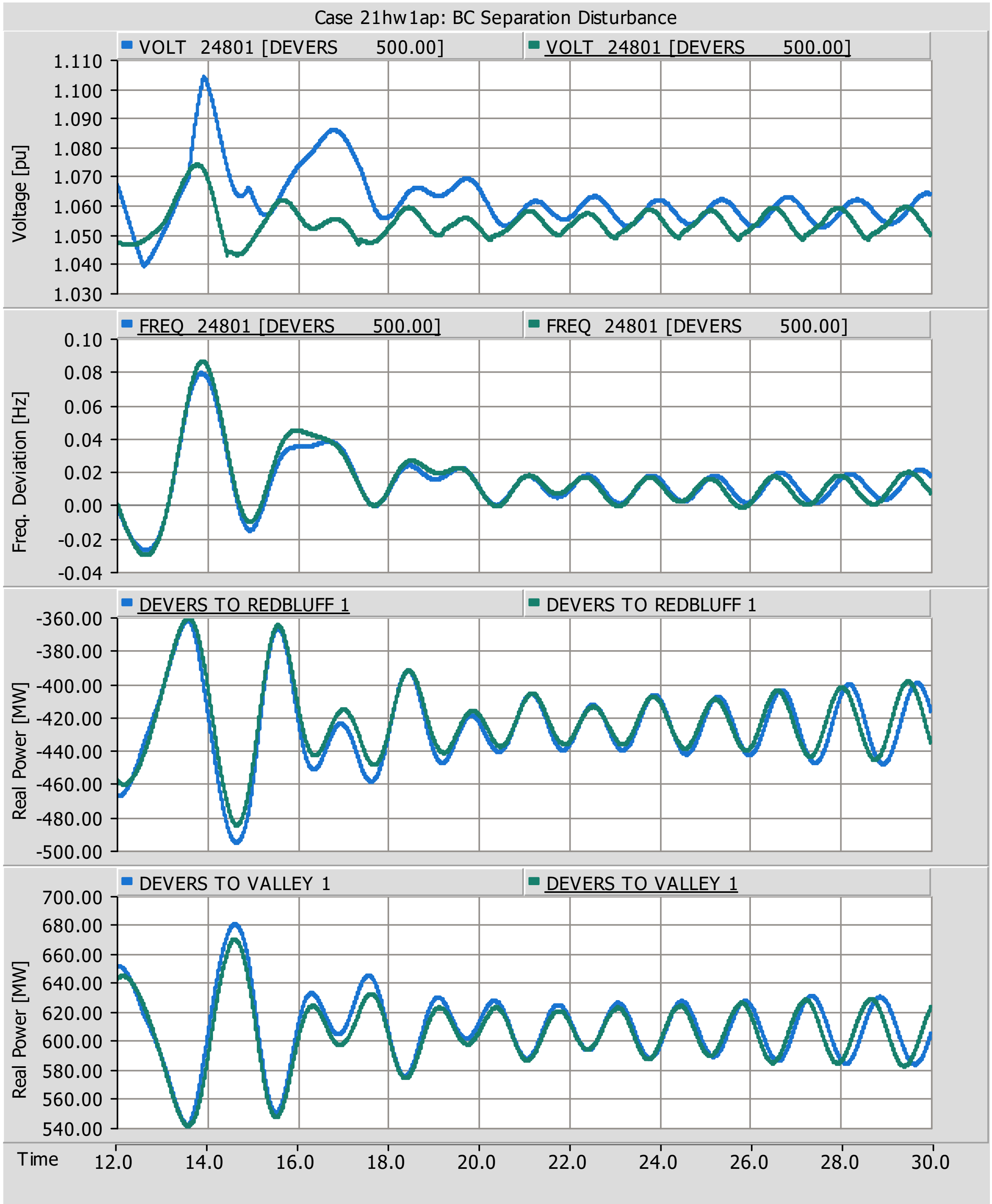

Figure 46: Results with and without the POD for the 'BC – NW Separation' disturbance with FACRI RAS scheme

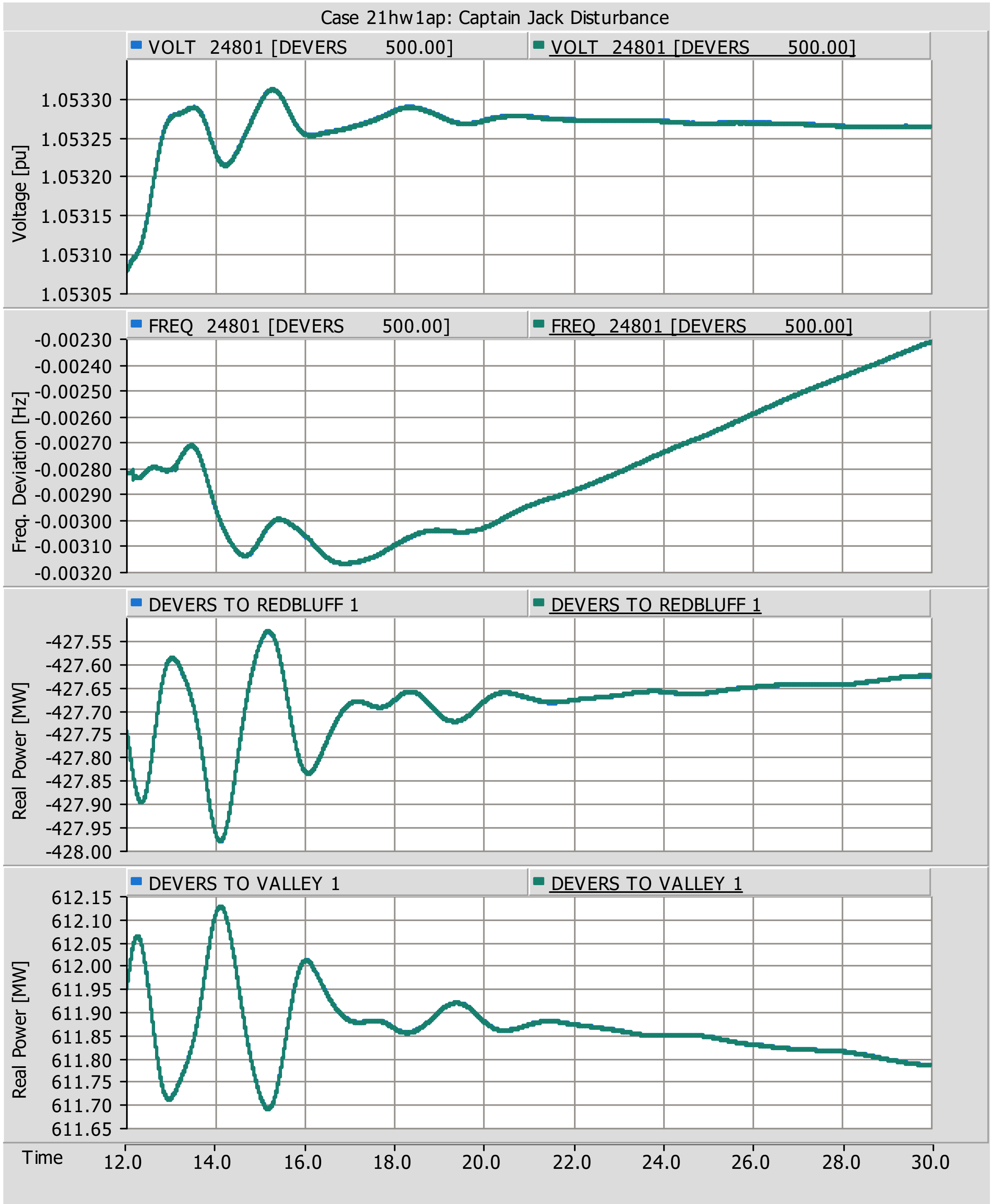

Figure 47: Results with and without the POD for the 'Captain Jack shunt capacitor' disturbance

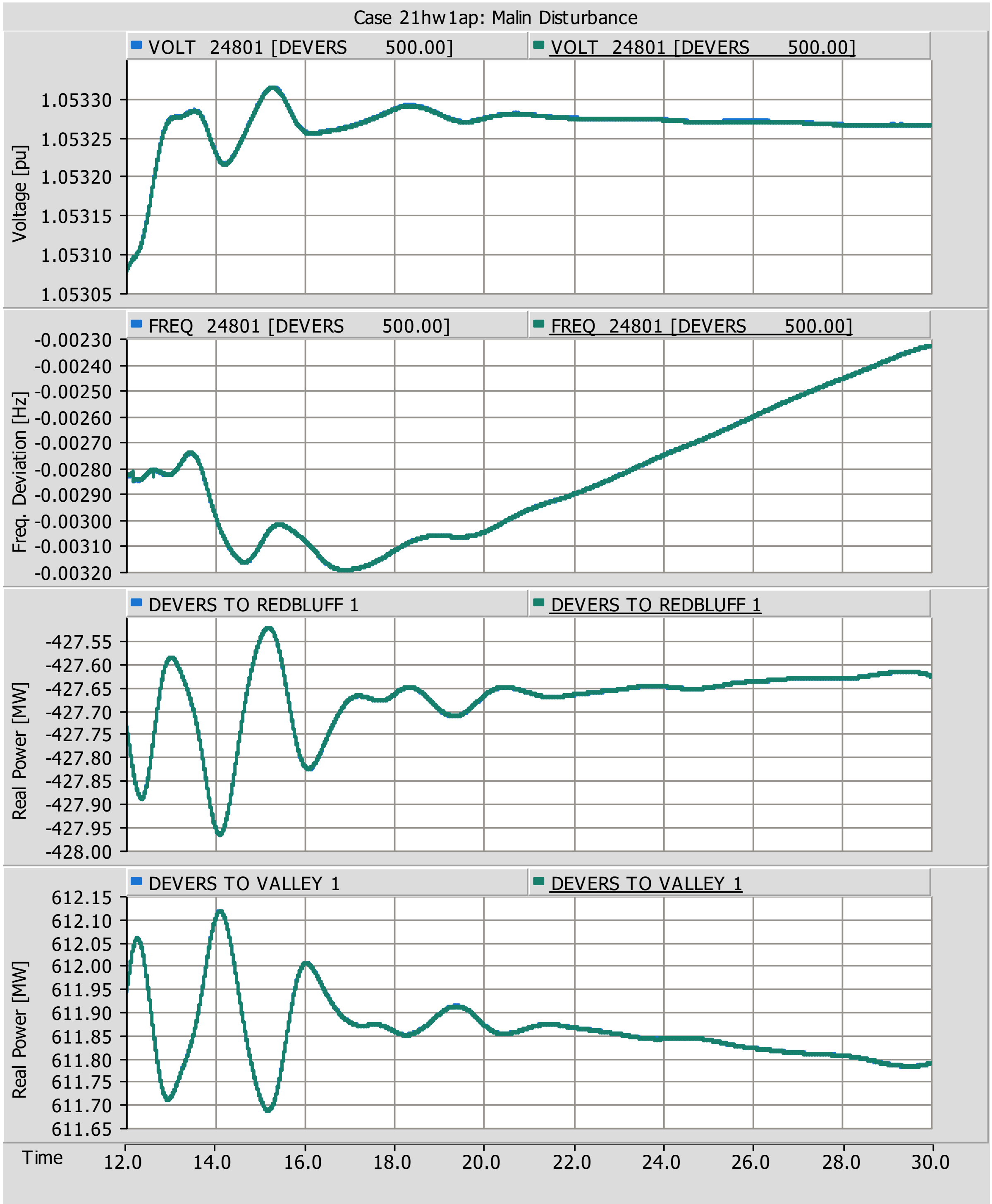

Figure 48: Results with and without the POD for the 'Malin shunt capacitor' disturbance

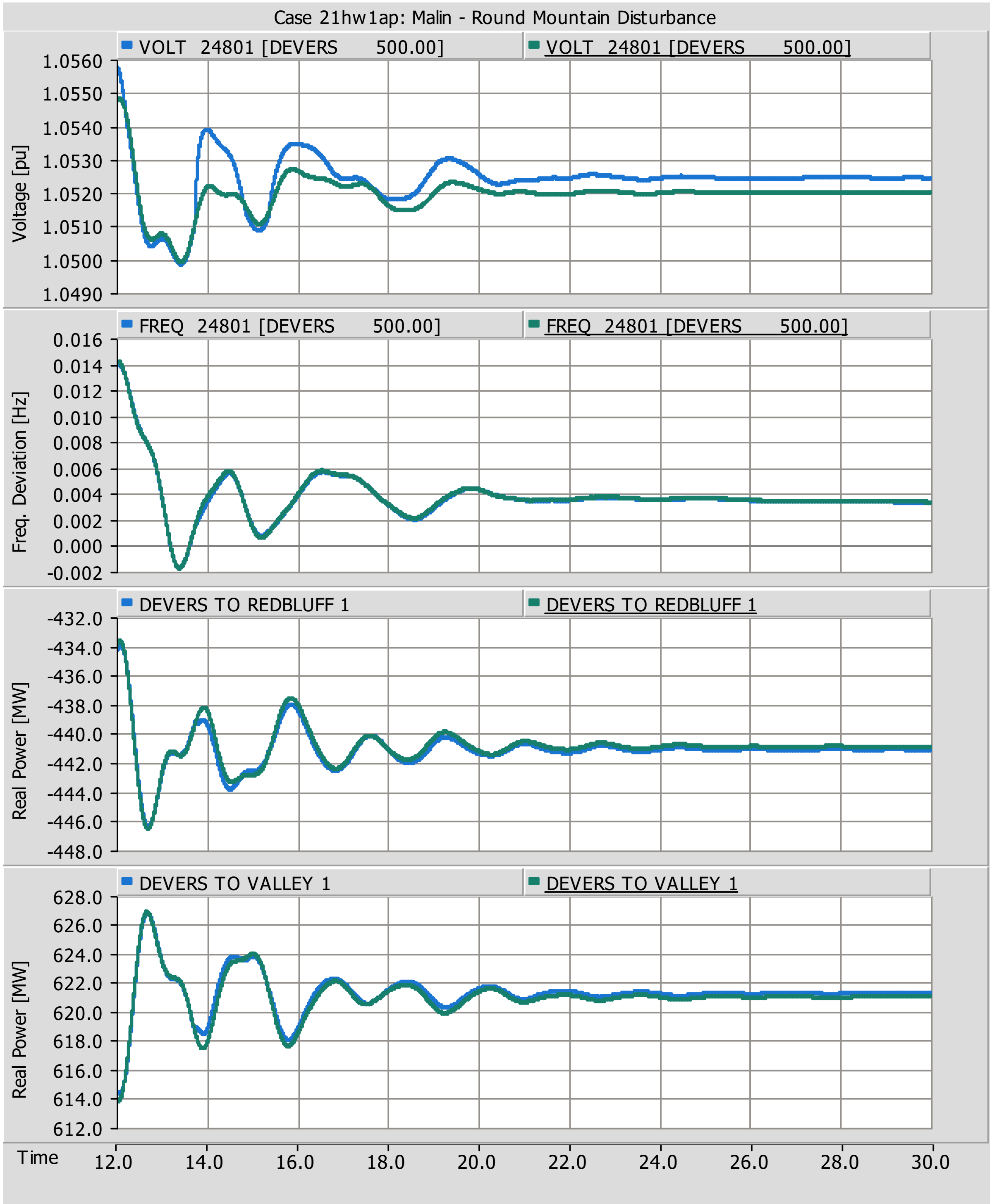

Figure 49: Results with and without the POD for the 'Malin – Round Mountain' disturbance

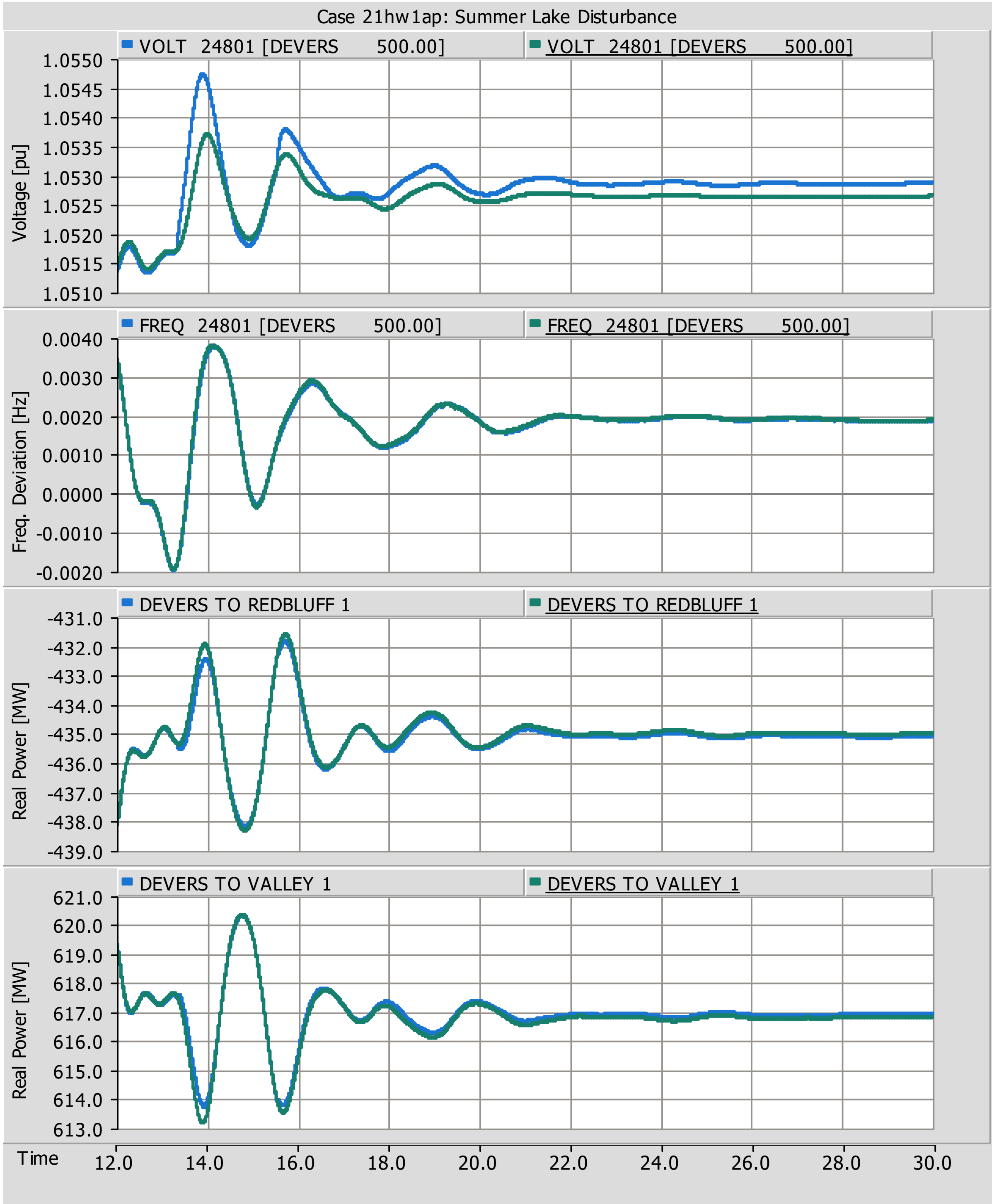

Figure 50: Results with and without the POD for the 'Summer Lake bus outage' disturbance

In some of the above disturbances, the SVC was able to influence the voltage at the Devers bus; however, the frequency and active power signals did not change with the POD. Therefore, the modes in these disturbances were uncontrollable.

7.4 High Load Summer Season of 2022 '22HS1ap'

For this case, the POD parameters were tuned to improve the damping performance of the modes listed in the previous section and the new values are listed in Table 12. The frequency response of the POD with the above parameters is shown in Figure 51.

Table 12: POD parameters for case '22HS1ap'

CON	Name	Value
J+15	POD Gain	0.2000
J+16	PT1 time constant [s]	0.0497
J+17	POD Wash-out filter differential time constant [s]	0.2050
J+18	POD Wash-out filter lag time constant [s]	0.4974
J+19	POD Lead-Lag filter 1 lead time constant [s]	0.5927
J+20	POD Lead-Lag filter 1 lag time constant [s]	0.4173
J+21	POD Lead-Lag filter 2 lead time constant [s]	0.5927
J+22	POD Lead-Lag filter 2 lag time constant [s]	0.4173
J+23	POD Lead-Lag filter 3 lead time constant [s]	0.5927
J+24	POD Lead-Lag filter 3 lag time constant [s]	0.4173
J+25	POD limit [pu, based on nominal voltage of HV busbar]	0.05

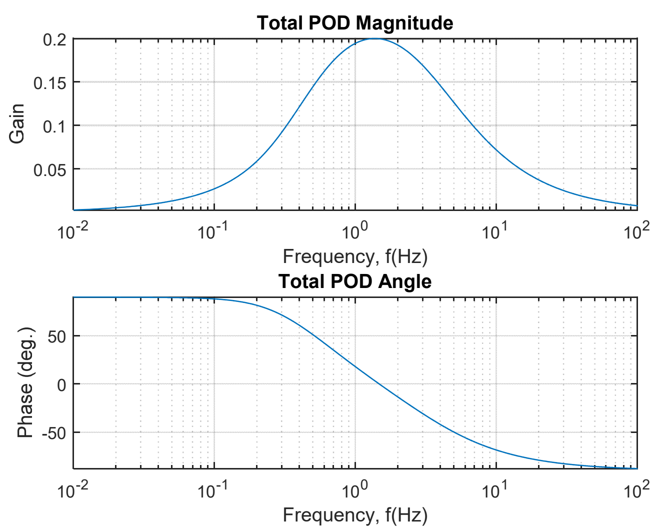

Figure 51: POD frequency response for case '22HS1ap'

7.4.1 Disturbances Located Close to Devers Substation

The identified modes for the disturbances located close to the SVC at Devers are shown in Table 13.

Table 13: Observable modes using the Prony analysis methods for with and without the POD

Disturbance	Channel	Without POD		With POD	
		Damping	Frequency	Damping	Frequency
Lugo – Mira Loma	P (Devers-Redbluff)	20%	0.46	22%	0.39
North Gila – Imperial Valley	P (Devers-Redbluff)	12%	0.54	11%	0.56
		9%	0.79	11%	0.77
PDCI Block	P (Devers-Redbluff)	10%	0.45	10%	0.46
Palo Verde	P (Devers-Redbluff)	23%	0.40	25%	0.40
	P (Devers-Valley)	18%	0.39	16%	0.50
Devers - Redbluff	P (Devers-Valley)	7%	0.78	6%	0.77
Devers - Valley	P (Devers-Redbluff)	8%	0.76	10%	0.77
		6%	1.48	7%	1.51
North Gila – Imperial Valley	Frequency (Devers)	17%	0.33	16%	0.33
		14%	0.83		

Figures 52 through Figure 56 show the voltage and frequency at the 500 -kV Devers bus and the active power transfers in the 'Devers-Redbluff' and 'Devers-Valley' circuits. The channels in blue are the results with the POD and the channels in green are the results without the POD.

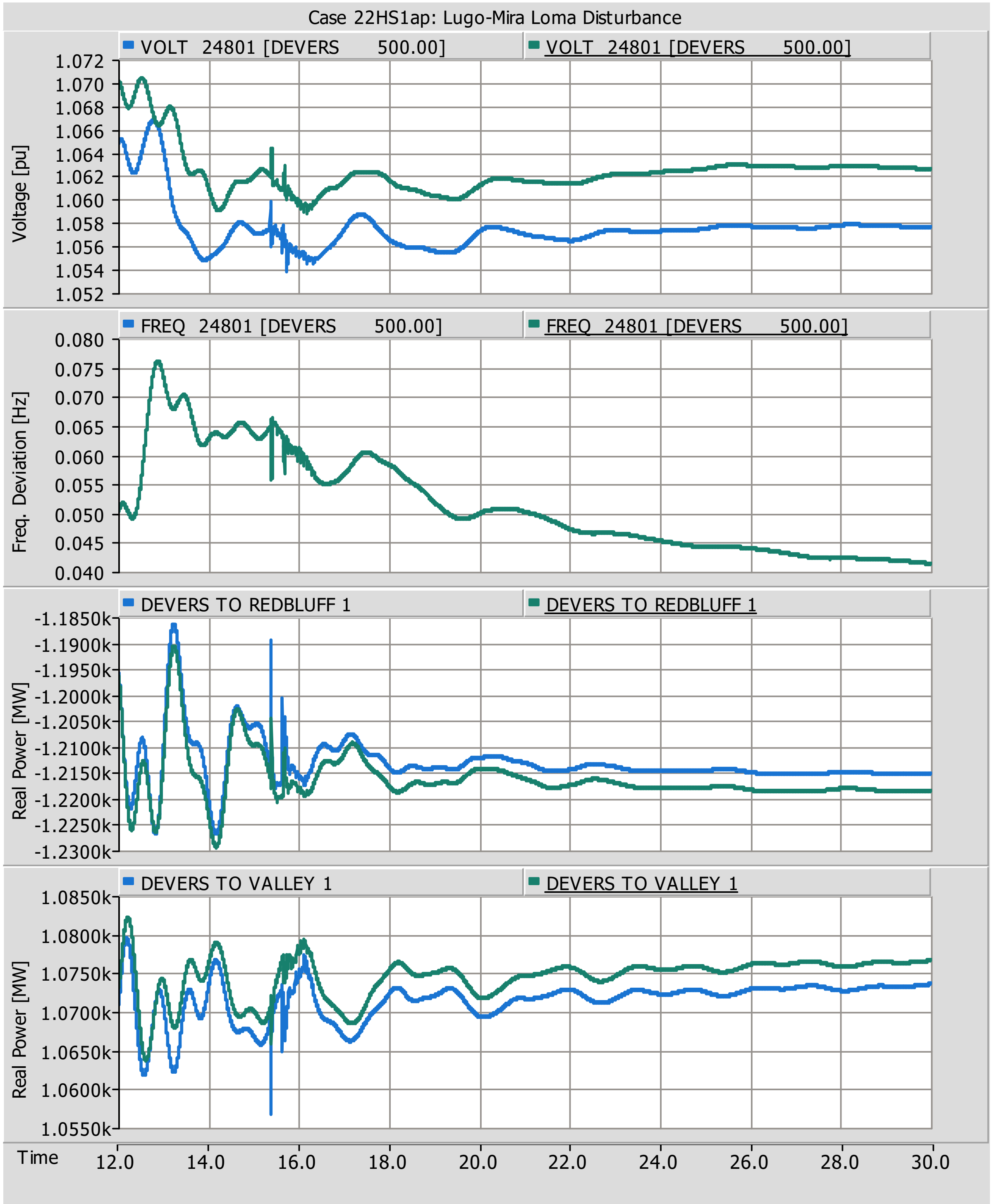

Figure 52: Results with and without the POD for the 'Lugo - Mira Loma' disturbance

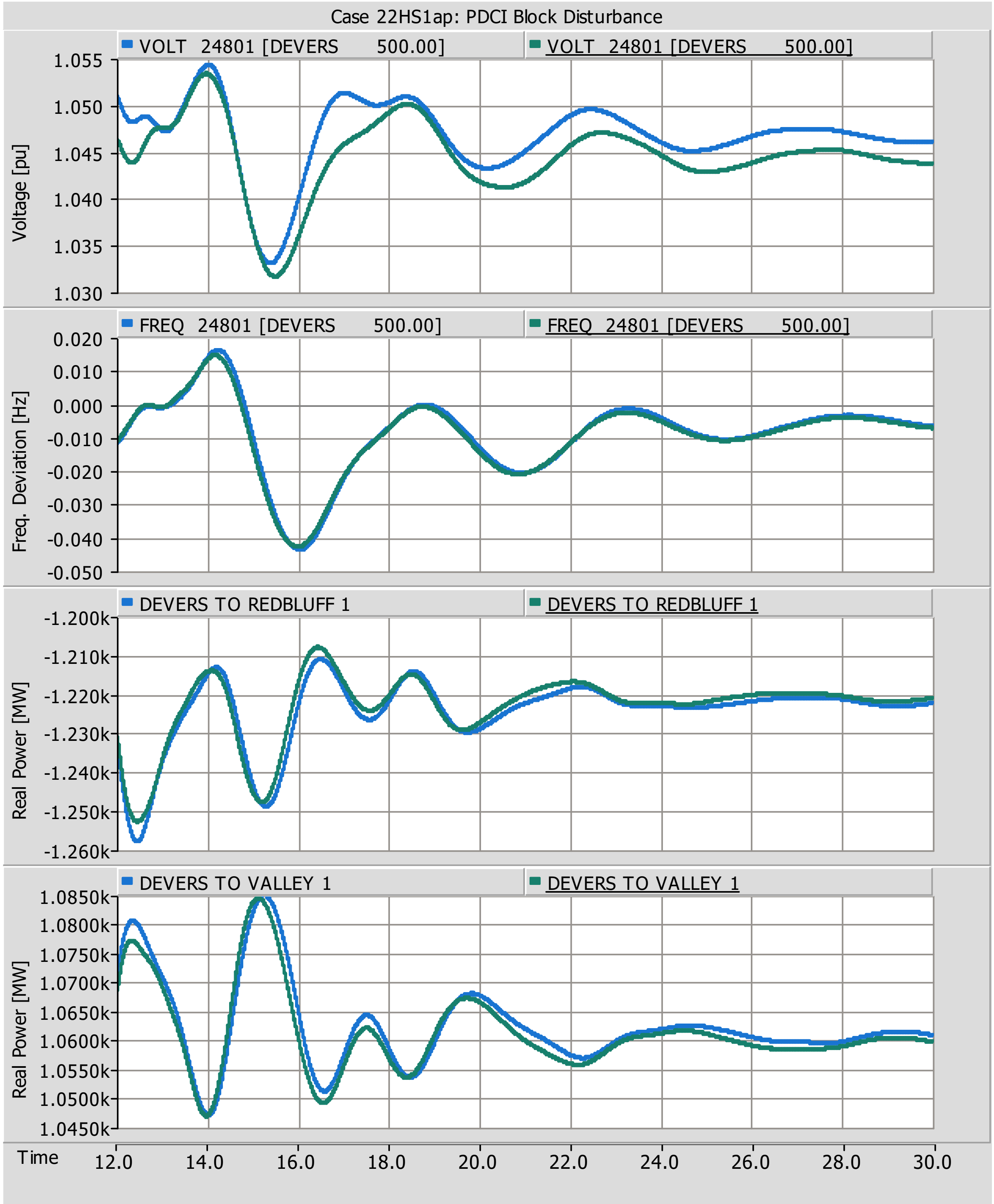

Figure 53: Results with and without the POD for the 'PDCI Block' disturbance

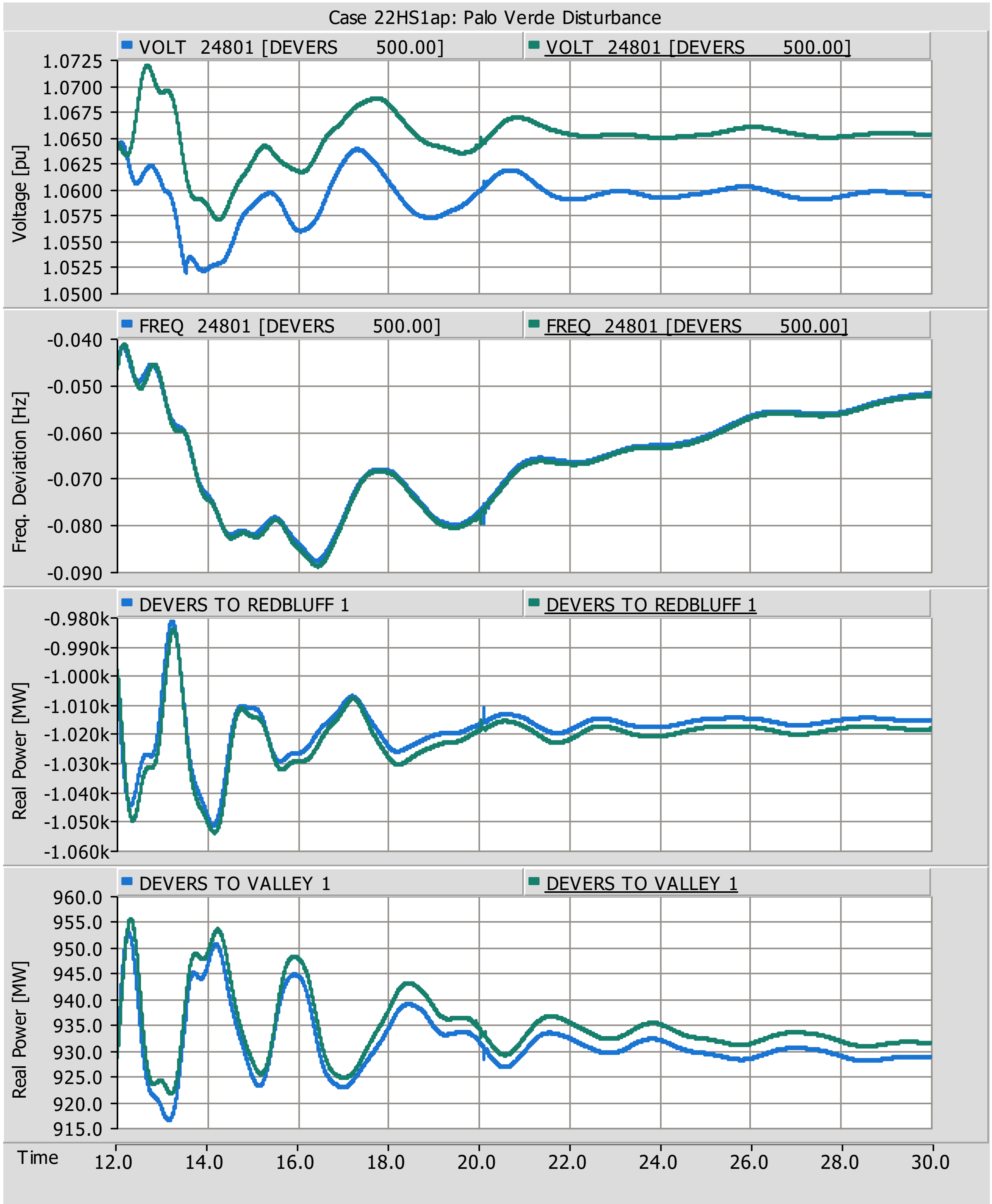

Figure 54: Results with and without the POD for the 'Palo Verde' disturbance

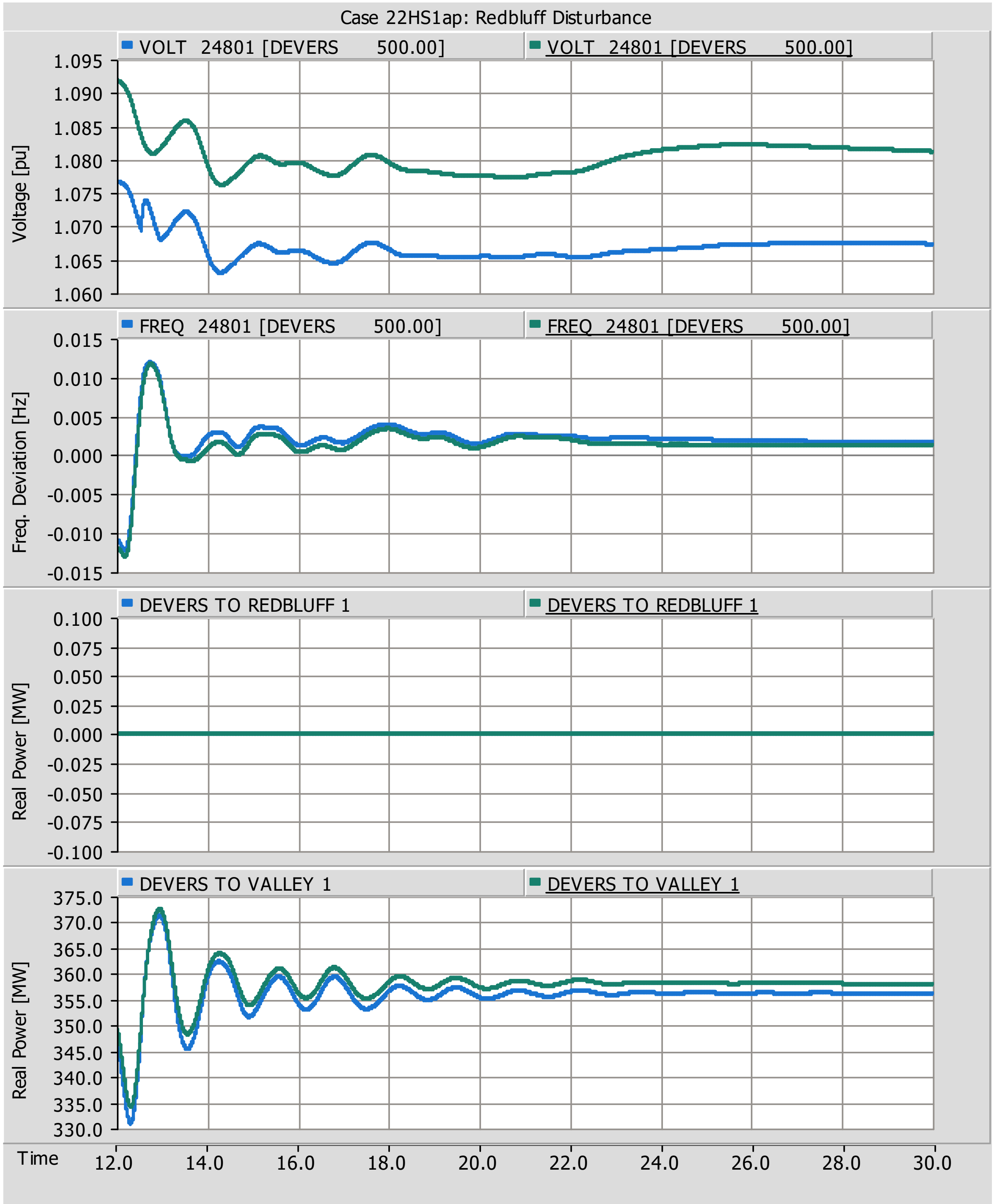

Figure 55: Results with and without the POD for the ‘Devers – Redbluff’ disturbance

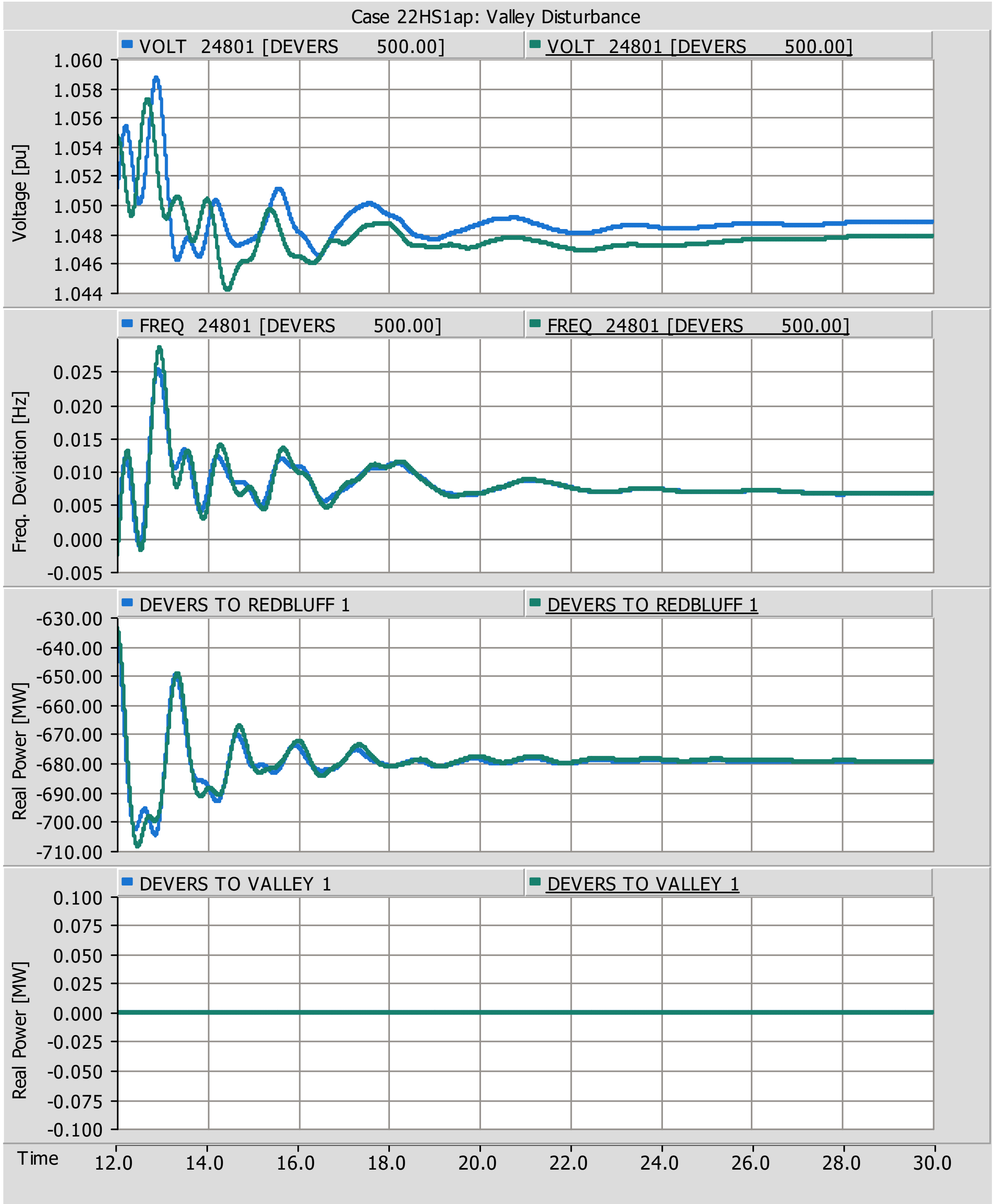

Figure 56: Results with and without the POD for the 'Devers – Valley' disturbance

In the above disturbances, it is shown that the POD was unable to control the modes observed at the Devers 500-kV bus. This agrees well with the results in Table 13, which shows that the damping with and without the POD were very similar.

7.4.2 Disturbances Located Far from Devers Substation

The identified modes for the disturbances located away from Devers substation are shown in Table 14.

Table 14: Observable modes using Prony analysis methods for with and without the POD

Disturbance	Channel	Without POD		With POD	
		Damping	Frequency	Damping	Frequency
Chief Joseph Brake Insertion	P (Devers-Redbluff)	10%	0.34	10%	0.34
Malin - Round Mountain	P (Devers-Redbluff)	17%	0.34	16%	0.39
		8%	0.50	7%	0.50
Round Mountain - Table Mountain	P (Devers-Redbluff)	8%	0.53	8%	0.51
Summer Lake Bus Outage	P (Devers-Redbluff)	16%	0.31	16%	0.32
Chief Joseph Brake Insertion	Frequency (Devers)	14%	0.35	20%	0.34
Malin - Round Mountain	Frequency (Devers)	28%	0.21	15%	0.20
Round Mountain - Table Mountain	Frequency (Devers)	22%	0.23	19%	0.23

Figures 57 through 60 show the voltage and frequency at the 500-kV Devers bus and the active power transfers in the 'Devers-Redbluff' and 'Devers-Valley' circuits. The channels in blue are the results with the POD and the channels in green are the results without the POD.

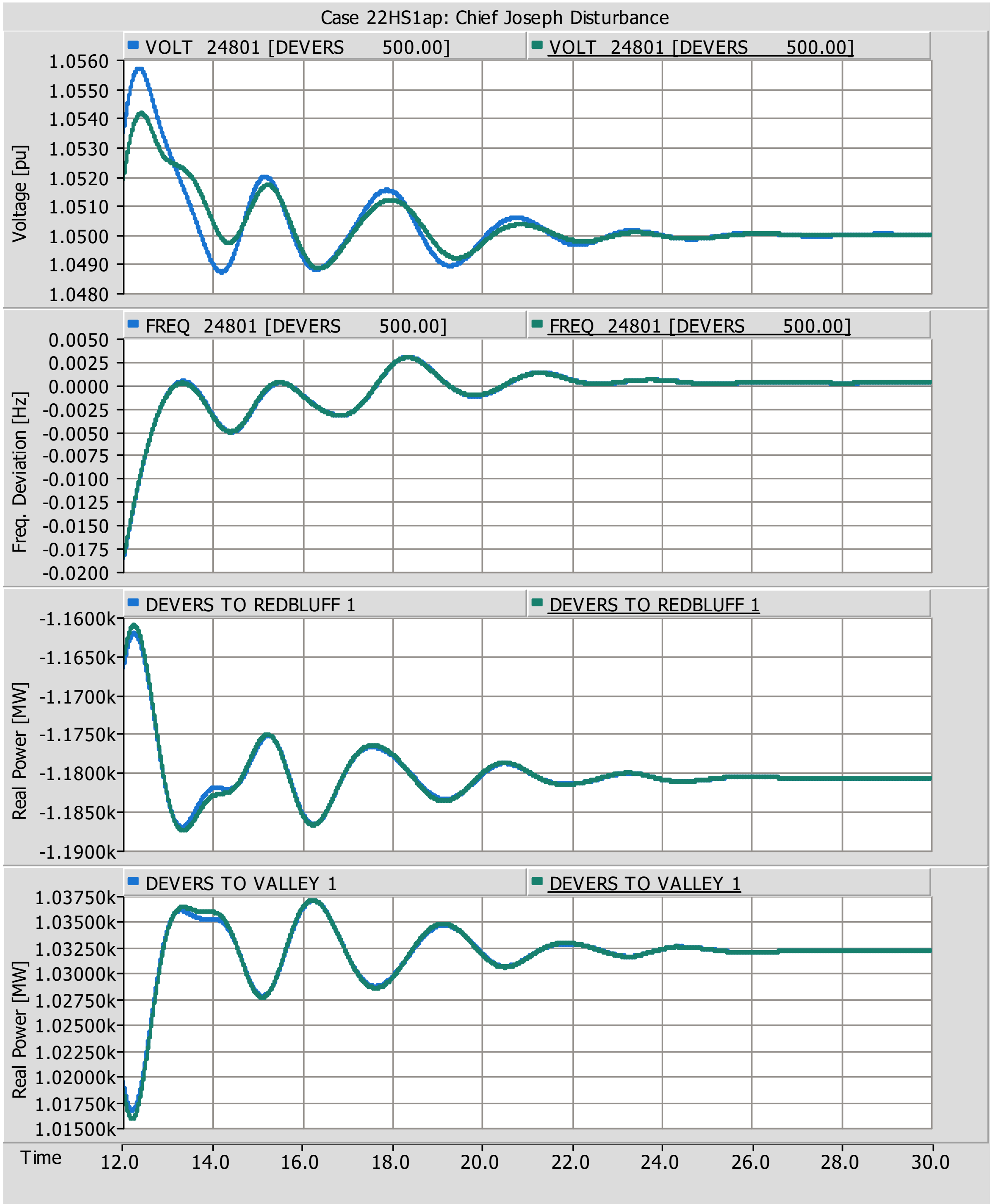

Figure 57: Results with and without the POD for the 'Chief Joseph brake insertion' disturbance

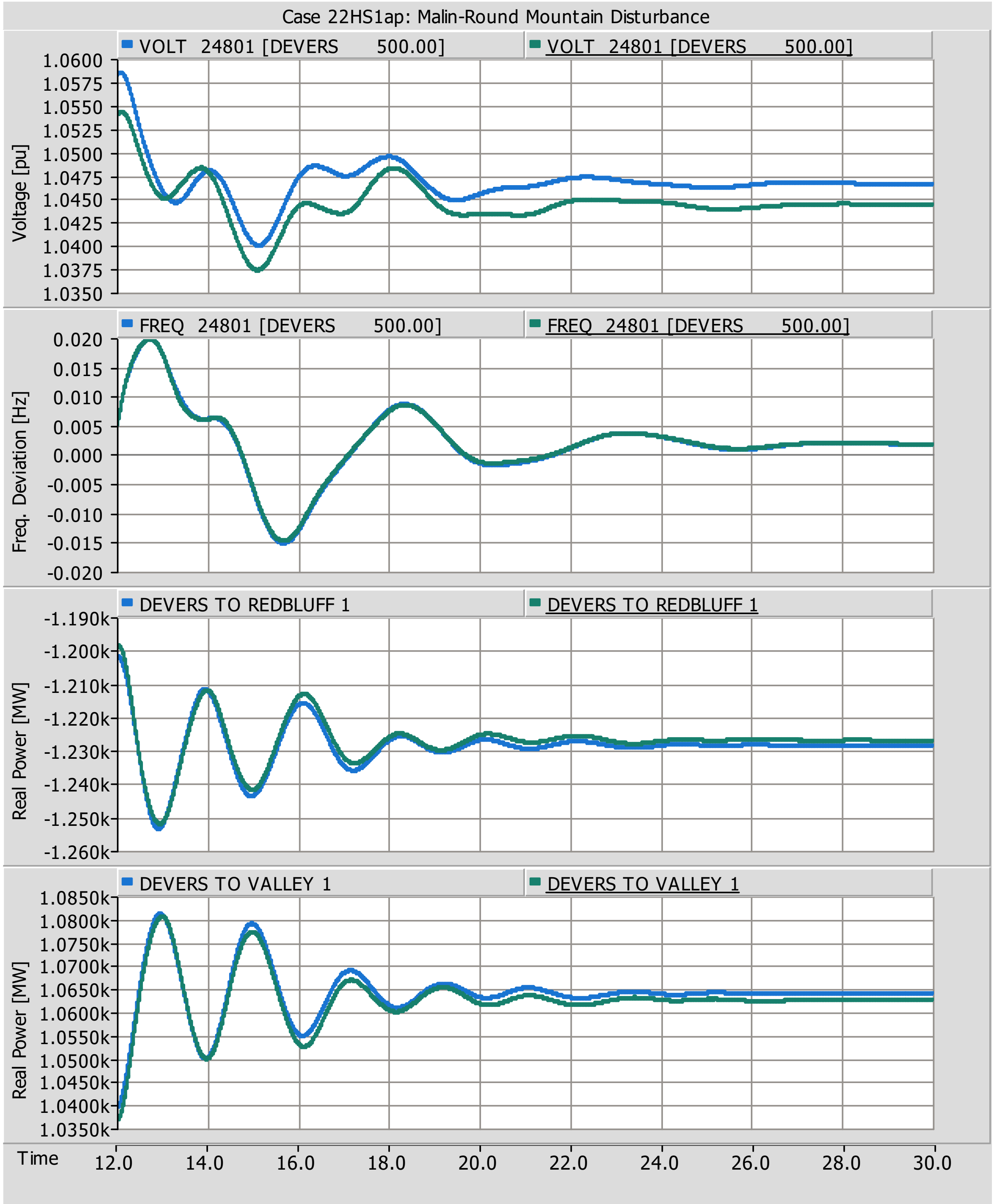

Figure 58: Results with and without the POD for the 'Malin – Round Mountain' disturbance

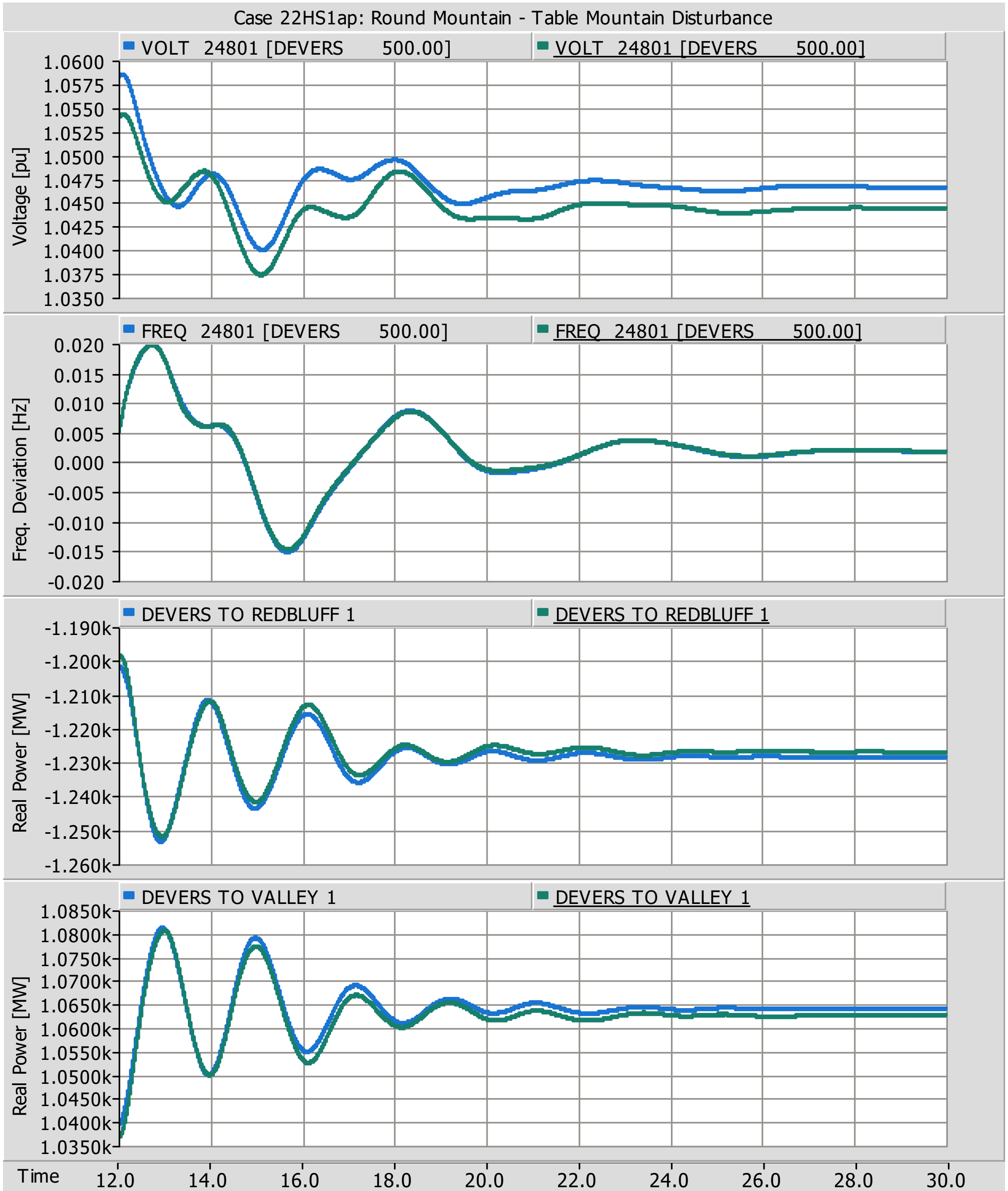

Figure 59: Results with and without the POD for the 'Round Mountain – Table Mountain' disturbance

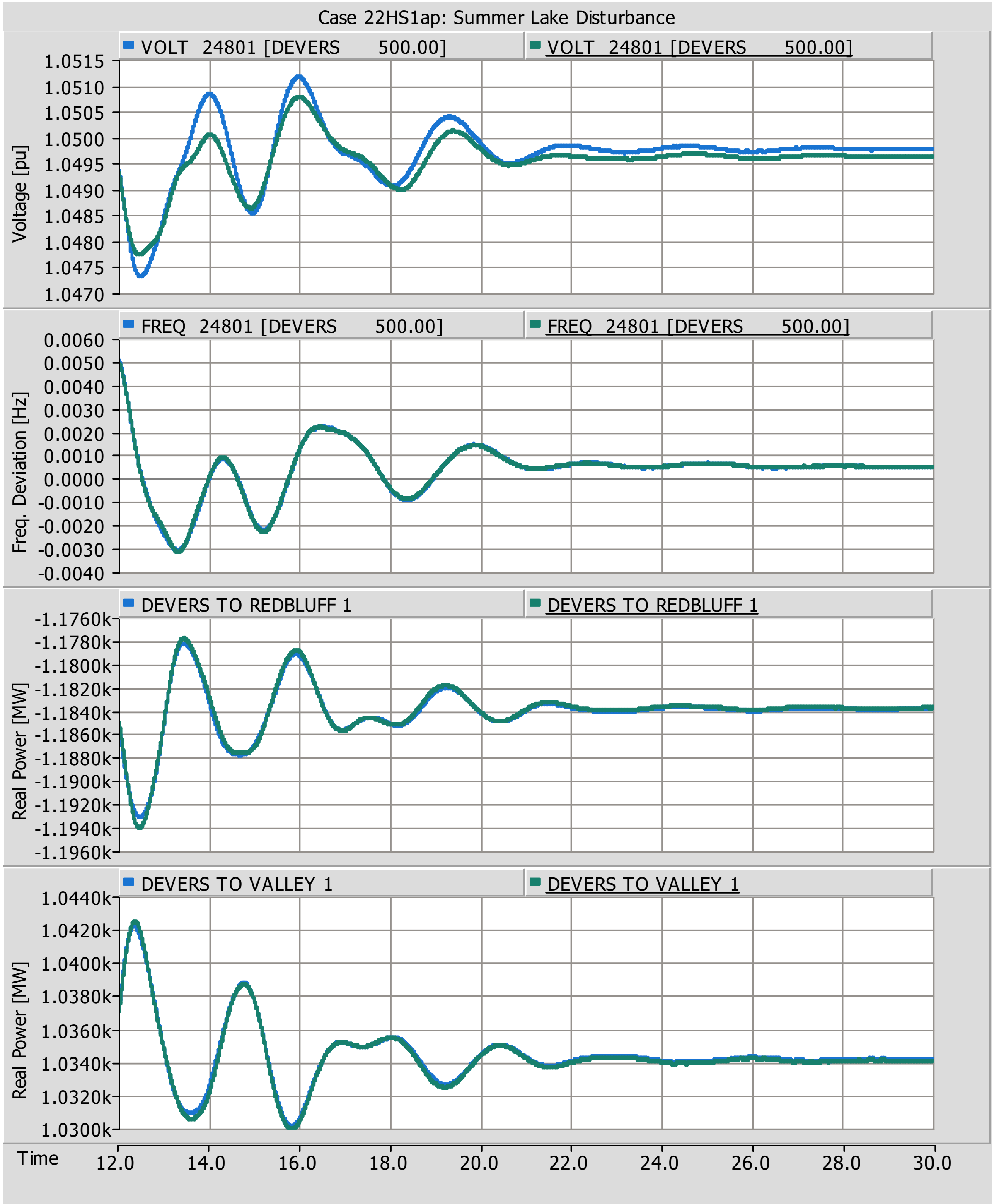

Figure 60: Results with and without the POD for the 'Summer Lake bus outage' disturbance

In the above disturbances, it was indicated that the POD was unable to control the modes observed at the Devers 500-kV bus. This agrees well with the results in Table 14, which shows that the damping with and without the POD was very similar.

7.5 Conclusion

As noted in the previous sections, given the necessity of ensuring grid stability with the growing use of inverter-based, renewable power generation, there is a need to emulate damping, a process that gradually reduces excessive oscillations and thus supports power system stability during disruptions.

In the Wide Area Management and Control Project, poorly damped inter-area oscillatory modes in the Western Electricity Coordinating Council (WECC) system were identified via a series of dynamic simulations. The Prony analysis technique was used to determine the frequency and damping coefficient of the inter-area modes.

Once the poorly damped modes were identified, the Power Oscillation Damping (POD) of the Static VAR Compensator (SVC) was tuned to improve the overall system damping. The performance of the proposed POD settings was then validated by conducting dynamic simulation with the POD enabled.

Several known (reported in literature) inter-area oscillatory modes from 0.2 Hz to 0.8 Hz can be observed from the location of the Devers SVC. Settings for the POD were determined to improve poorly damped inter-area oscillatory modes.

Once the POD was enabled, a change in the voltage (compared to the SVC voltage without the POD) of the Devers SVC was observed. This change in SVC voltage has the same frequency of the oscillation mode, which is required to be damped. This was observed in most of the fault-recovery conditions studied. This proves that the inter-area mode is “observable” in the selected input (frequency deviation of Devers 500-kV bus).

In general, improvements of damping coefficients of the inter-area oscillation modes were observed – an important finding to address the safe and reliable integration of increasing amounts of renewable energy resources on the electric grid.

8 Stakeholder Engagement

This project incorporated many stakeholders. Externally, the project team worked with Siemens Energy, equipment suppliers and Manitoba Hydro International Ltd. (MHI). Internally, the project team and project stakeholders included Substation Apparatus Engineering, Transmission Interconnection Planning (TIP), Grid Operations (GCC), and various Transmission and Distribution groups. The major internal stakeholder for this project was SCE’s Transmission Interconnection – Planning Group. This group was engaged on a quarterly basis to update on milestone progress, and also served as the project’s technical advisory committee. In addition, this stakeholder reviewed the project reports and provided feedback on whether the results were reasonable.

Appendix C

Versatile Plug-in Auxiliary Power System

Final Project Report

Versatile Plug-In Auxiliary Power System (VAPS) Final Project Report

Developed by

SCE Transmission & Distribution, Grid Technology and Modernization

December 2019

Southern California Edison
2131 Walnut Grove Avenue
Rosemead, CA 91770

Acknowledgments

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1 Executive Summary

Southern California Edison's (SCE) "Pathway 2045"[1] maps out the approach to achieve long-term decarbonization goals, with the transportation sector as a focal point. As part of its work in this area, SCE's Versatile Plug-In Auxiliary Power System (VAPS) Project demonstrated the use of advanced lithium-ion battery systems, as in modern electric vehicles (EVs), in utility fleet vocational applications as a means of facilitating progress to full electrification.

The VAPS Project consisted of six subprojects – light-duty platform; heavy-duty platform; medium-duty platform; and small, medium and large power systems – that attempted to electrify some of SCE's fleet vehicles and certain jobsites that seemed amenable to electrification at the time. (See Project Summary, Section 3, and **VAPS Subprojects**, Section 4, for more details.)

The subprojects had varying degrees of success. In general, those using second-life batteries and those with retrofitted vehicles were more challenging, requiring a greater degree of modification to the original system, which is generally more complex. In contrast, systems that used a less demanding strategy were designed by the original equipment manufacturer (OEM) to work electrically with hybrid systems, and had a higher success rate. Overall, the VAPS Project helped inform several electrification strategies for SCE's fleet. For example:

- One sub-project led to a new fleet electric deployment – the electric cable puller.
- One sub-project provided key recommendations that would enable a truck electric-hybrid system to achieve success in the fleet by identifying a disqualifying charger system and demonstrating a compliant replacement.
- One project demonstrated that heavy-duty full electric-drive trucks were not ready for fleet needs, but a medium heavy-duty electronic power takeoff (ePTO) application was.

2 Background

By 2045, California will undergo a remarkable evolution. With the adoption and deployment of currently available and emerging technologies, California is committed to achieving carbon neutrality to reduce the threat of climate change – which already is causing more frequent and extreme weather events, among other serious impacts. This statewide commitment will require substantial decarbonization of all sectors of the economy and will necessitate rigorous planning to keep energy safe, reliable and affordable.

1 https://on.edison.com/2R1VoKb

As noted above, SCE's "Pathway 2045" maps out the approach to achieve long-term decarbonization goals, with the transportation sector as a focal point. Statewide, transportation accounts for 45% of the greenhouse gas emissions that cause climate change, and more than 80% of air pollution, which results in respiratory and other health issues. Medium-duty, heavy-duty and non-road vehicles contribute substantially to these emissions in Los Angeles County. To meet federal health-based air quality standards, by 2030 California must cut in half the amount of petroleum used in cars and trucks.[2]
In addition, achieving California's 2045 carbon neutrality goal requires the electrification of three-quarters of light-duty vehicles, two-thirds of medium-duty vehicles and one-third of heavy-duty vehicles.

SCE continues to collaborate with a wide array of organizations, including the Electric Power Research Institute (EPRI), the Edison Electric Institute (EEI) and the Smart Electric Power Alliance (SEPA), to take a leadership role in fleet electrification to help address these challenges. Deployment and use of plug-in hybrid vehicles (PHEVs), battery-electric vehicles (BEVs), and portable electric energy systems installed on existing and new fleet vehicles can help improve jobsite safety and eliminate or minimize engine idle. Decreased idle time means fewer carbon and air polluting emissions, less noise and longer engine life spans.

The VAPS applications covered in this report can be applied to existing as well as new vehicle drivetrain systems, as well as secondary systems such as air conditioning (A/C), to perform varying degrees of jobsite electrification. In addition to eliminating or minimizing engine idle and enhancing jobsite safety, VAPS technology can be used to refine EV and subsystem specifications because the remote data collection on these systems tallies and stores information on jobsite power and energy requirements. VAPS also can contribute to training efforts while educating employees about the advantages of electrification at work locations.

The VAPS Project was designed to evaluate the benefits and impacts of this technology, which was envisioned by SCE and subsequently independently developed by EPRI. Leveraging the core technology, and coordinating with SCE's Transportation Services Department (TSD) (including TSD Fleet Asset Management and TSD Fleet Planning and Strategy), as well as with Transmission & Distribution (T&D) Construction Methods, SCE's Grid Technology and Modernization Group worked with suppliers to specify, procure and test multiple VAPS platforms in several categories. (See VAPS Subprojects, Section 4, for details.)

SCE has an annual fleet budget allocation of at least 5% to purchase EVs, and the technologies assessed in the VAPS Project help to identify options that SCE's fleet and customer fleets can procure in the future.

2 https://ww3.arb.ca.gov/newsrel/petroleum_reductions.pdf

3 Project Summary

The VAPS Project is in alignment with SCE's internal Distribution Electric Transportation Strategic Initiative and the SCE Customer Energy Choices Strategic Goal, with the objectives of 1) removing barriers to customer adoption of transportation and building electrification technologies, and 2) medium- and heavy-duty electric vehicles can meet customer needs:

1. The VAPS technology tested and evaluated in the project electrifies light- and medium-duty vehicles. VAPS can be applied to drivetrain systems, as well as to auxiliary systems such as A/C and tool circuits, to provide varying degrees of jobsite electrification and idle-free work operation. In addition, the VAPS Project procured and tested multiple energy capacity-sized portable systems to electrify a variety of job functions. The mobile power systems tested can provide an energy source for a number of applications while reducing criteria air pollution and greenhouse gas emissions at construction sites, in emergency response situations, for special events, and other needs.
2. Findings from the VAPS Project also contribute to the electrification of SCE's fleet over a wide range of vehicle types and job functions using different technology platforms. Given SCE's 5% annual minimum budget target for fleet electrification, the VAPS Project work can effectively increase EV options. The project also supports the Edison Electric Institute (EEI) Industry-Wide Plug-In Electric Vehicle Market Readiness Pledge: "Utilities pledge to develop new sustainable fleet acquisition and operations plans, helping drive development and significant deployment of electric transportation solutions in light-, medium- and heavy-duty utility applications."

The VAPS Project was implemented through the California Public Utilities Commission's (CPUC) Electric Program Investment Charge (EPIC) II Program.[3] EPIC aims to fund applied research and development, technology demonstrations and deployments, and market facilitation programs for the benefit of the electricity ratepayers of SCE and the state's other investor-owned utilities. The utilities are limited to demonstrations, which focus on advancing the grid.

Based on Figure 1. Joint Utilities EPIC Framework, the VAPS Project concentrated on the Customer-Focused Products and Services Enablement area and on supporting the Electric Transportation Key Drivers and Strategies initiative. The project also addressed the evaluation of jobsite fleet electrification technology that can enhance safety and reliability.

3 2015-2017 Investment Plan Application (A.)14-05-005.

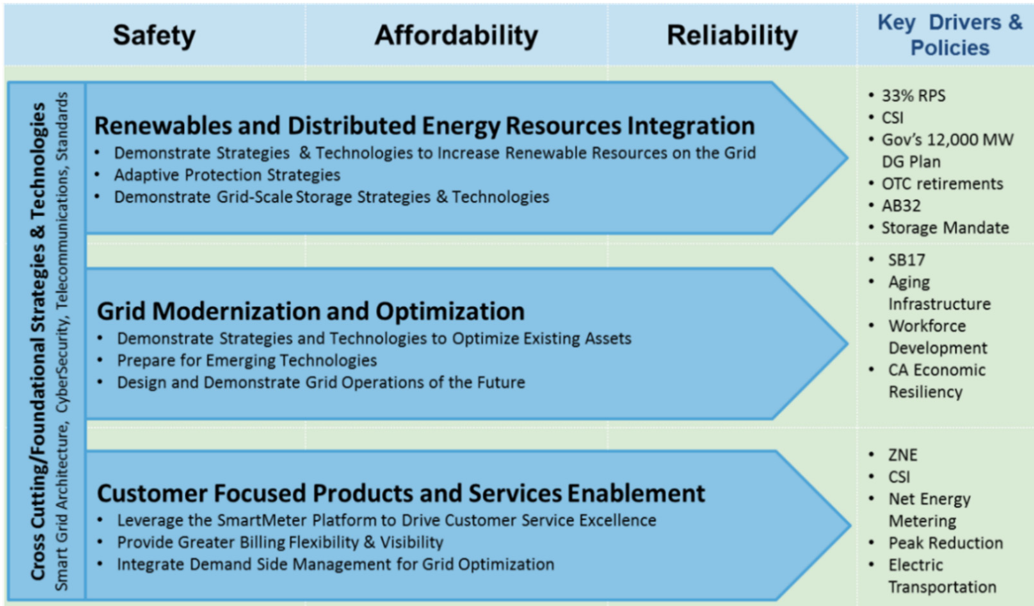

Figure 1. Joint Utilities EPIC Framework[4]

The initial scope of work identified for the VAPS Project included the following subcategories:

- Light-Duty VAPS Platform: PHEV Pickup Truck
- Heavy-Duty VAPS Platform: Class 8 PHEV or BEV Flatbed
- Medium-Duty VAPS Platform: Class 5 or 6 PHEV Boom Truck or Short Flatbed
- Small, Medium and Large Power Systems:
  - Small energy secondary system targeted toward light- to medium-duty vehicle idle elimination with an emphasis on electric air conditioning
  - Medium battery energy electrification system to reduce medium-duty vehicle work site idling
  - Large battery energy electrification system with maximum energy storage to electrify the most energy-intensive work applications

These subprojects were designed to create a detailed specification for each architecture, identify all feasible suppliers, request proposals from each, and select a final supplier(s) for each category if the preliminary assessments were viable. This report summarizes the scope and results, among other details, for each subproject.

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[4] *See* "Application (A.)14-05-005 amendment to Application of Southern California Edison Company (SCE) for Approval of Its 2015-2017 Triennial Investment Plan for the Electric Program Investment Charge," May 1, 2014, for more details on the EPIC program and SCE's 2015-2017 Investment Plan Application.

3.1.1 Problem Statement

SCE is committed to electrifying its fleet, but is challenged by the lack of commercially available solutions that meet the company's operational requirements.

With fleet vehicles, much of the daily duty cycle, and thus fuel consumption and emissions, are characterized by stationary vehicle engine operation that supports safety lights, cabin conditioning, construction tools, radios, computers, hydraulics, and other equipment needed for jobsite work. Use of electric-powered vehicles offers the opportunity to significantly reduce fuel consumption, emissions, noise and wear on engines.

To address these issues, SCE undertook the VAPS Project to evaluate the benefits and impacts of technology for electrifying both its fleet and jobsite applications.

4 VAPS Subprojects

The following sections address the subprojects included in the VAPS Project. Background memos and additional materials are located at Edisonintl.sharepoint > TD > PMO > IIM-14-0075 > Documents > 03_Proj_Mgt > 3.13_Reports > Final Report > Appendices.

4.1 Light-Duty VAPS Platform: PHEV Pickup Truck

4.1.1 Overview

This subproject was designed to identify a supplier with reliable and proven VAPS-type plug-in technology that it could apply to the standard SCE Ford F-150 pickup truck configuration. SCE's fleet includes more than 1,500 pickup trucks, and displacing on-road and idle fuel consumption with electricity potentially could reduce fuel costs by more than $1 million annually. When this subproject began, no OEM electric pickup trucks were available, and the electric-powered pickup trucks offered by other firms were not proven reliable enough for utility work. Therefore, the subproject was designed to provide a recommendation to SCE's Transportation Services Department (TSD) and T&D on a converted PHEV pickup truck that could meet fleet operational and safety requirements while providing significant savings.

4.1.2 Scope of Work

This subproject called for SCE to procure a PHEV pickup truck conversion with an advanced lithium-ion battery and evaluate its performance at the utility's Electric Vehicle Technical Center (located in Pomona) on criteria including performance, reliability, fuel economy and electrical system impact. If the results were satisfactory, SCE then planned to conduct a field trial in its fleet.

4.1.3 Procurement

Because of the unavailability of a vendor to provide a VAPS conversion in the Class 2a (Ford F-150 category) to meet its specifications, SCE's project team worked with fleet stakeholders to re-scope this subproject to include the Class 3 PHEV range. Only Efficient Drivetrains, Inc. (EDI) offered such an acceptable option at that time, so SCE selected the company as the vendor, with a GMC Sierra 3500 as the base vehicle. The initial delivery of the PHEV pickup was delayed when EDI found issues with noise and vibration in the converted drivetrain and the newly installed electric parking brake in the PHEV components. Therefore, SCE's vehicle testing began later than planned.

4.1.4 Results

June 2018: SCE initiated testing of the PHEV pickup truck and immediately encountered difficulties, with the vehicle displaying a "return to dealer" error message. EDI determined that this was caused by a software issue, resulting in only one of the battery packs being charged. The issue was resolved in July, as well as a problem that occurred with the electric parking brake.

July 2018: Testing resumed, but was immediately suspended when the vehicle suffered a loss of drive power in all driving modes (charge depleting and charge sustaining). EDI sent a technician to SCE in August to bleed air from the hybrid drivetrain coolant lines.

October 2018: SCE garage personnel were unable to resolve Diagnostic Trouble Codes (DTCs) for the boost control solenoid (used to regulate pressure in the turbocharger). In addition, the vehicle registration was coming due, but a mandated recall for emissions issues required that the Engine Control Unit (ECU) needed to be reprogrammed at an OEM dealership before the registration could be renewed. The dealership expressed concern that the ECU had been reprogrammed, but EDI indicated that it had not.

November 2018: The vehicle experienced a loss of power while on road due to electric motor overheating. This was immediately reported to EDI, but the company did not respond until January 2019, at which point it suggested sending the vehicle to its facilities in Northern California.

February 2019: SCE made arrangements to send the PHEV pickup to EDI's facilities for repair. EDI received the vehicle on February 20, 2019. However, as of March 26, 2019, the company had not begun repair work, so SCE brought the vehicle back to its Electric Vehicle Technical Center in Pomona.

April 2019: SCE's Lead Project Engineer recommended to SCE management that the vehicle be returned to non-PHEV status.

4.1.5 Lessons Learned

At the start of this subproject, SCE determined a PHEV pickup truck, as opposed to a full battery-electric model, would be necessary for utility work due to then-limited battery range. However, technical challenges are inherent any time a post-OEM vendor upfits a vehicle to a plug-in hybrid, because it must be integrated with the existing vehicle control systems.

To minimize these risks, SCE decided to select a vendor that had previously completed conversions with a similar vehicle with successful outcomes for Pacific Gas and Electric Company. Yet even this more cautious approach did not prove sufficient and EDI (which during the subproject was acquired by Cummins Inc.) was unable to resolve the vehicle problems.

Although the fully integrated vehicle drive system blending both OEM mechanical drive and added electric drive could not be achieved to fleet-level reliability, the core advanced battery system was technically complete and will serve as a platform for future Cummins electric-drive systems, including Class 4 through Class 8 trucks.[5]

4.2 Heavy-Duty VAPS Platform: Class 8 PHEV or BEV Flatbed

4.2.1 Overview

For this element of the project, SCE planned to purchase and then evaluate a converted electrified Class 8 flatbed truck in both the lab and its fleet. At the time of the subproject's initiation, there were at least three stakeholders in SCE's Material Handling Division that indicated interest in using the truck in day-to-day operations, as part of a demonstration.

SCE uses Class 8 flatbeds for delivering heavy electrical components, such as large transformers, to the field. The subproject's goal was to demonstrate that a fleet platform Class 8 vehicle converted to a plug-in electric system could meet the fleet's operational needs while providing the electrification benefits previously outlined in this report.

When the project was initiated, state-of-the-art plug-in battery-electric Class 8 converted trucks demonstrated the ability to transport the same loads as internal combustion-based vehicles for up to 100 miles. SCE identified certain trucking applications that transport materials over short distances to repeat destinations where chargers could be installed. Enabling an option to electrify this category could boost the heavy EV truck platforms and help SCE meets its fleet electrification goals.

(Note: There currently are several manufacturers with Class 8 electric-powered tractors in different stages of development, but none of them were developing a Class 8 cab chassis when this subproject began.)

4.2.2 Scope of Work, Procurement and Results

This subproject was intended to evaluate the vehicle's range, performance, energy consumption, emissions reductions, functionality, reliability and acceptance under

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[5] Cummins PowerDrive for Electric Trucks, https://www.cummins.com/electrification/powerdrive-for-electric-trucks. Accessed February 2020.

multiple driving conditions to ensure that it was functional and effective for its application. If the system had proven to be reliable and safe, it then would have been placed into SCE's fleet for services and further evaluation.

In conjunction with SCE's Electric Drive Systems (EDS) Group, along with other stakeholders, the project specified the desired truck platform, engaged a vendor and acquired a base truck. After some time working with the vendor, SCE terminated the purchase due to the vendor's inability to provide an operational vehicle, per the specification and performance period in accordance with their Purchase Order. Consequently, the Heavy-Duty VAPS Platform was de-scoped from the VAPS Project.

4.2.3 Lessons Learned

While several manufacturers (such as Tesla, Kenworth, Volvo, Thor, Daimler and Peterbilt) are preparing to enter the Class 8 market with electric or PHEV semi-tractors, SCE had difficulty finding a vendor willing and able to incorporate the technology into a Class 8 capacity flatbed. This does not reflect technology maturity, but rather the OEMs' allocation of resources to develop the initial semi-tractor vehicles. Once the market is more established, the technology should be easily adaptable to the flatbed vehicle type.

4.3 Medium-Duty VAPS Platform: Class 5 PHEV 9-Foot Flatbed

4.3.1 Overview

This subproject initially focused on 1) identifying a supplier with the electric-drive technology to match the performance of a standard Class 5 flatbed payload, but with significantly improved gas mileage; and then 2) converting the vehicle and evaluating its actual range, energy consumption, functionality and reliability under multiple driving conditions.

Several potential vendors were assessed for this subproject, but none were capable of producing a PHEV or even an EV that met SCE's needs. Instead, SCE pursued an opportunity to utilize an Altec TA-60 vehicle retrofitted with an Odyne hybrid system capable of jobsite idle mitigation, in conjunction with an Air Quality Management District (AQMD) Contract Number 14222-funded program.

The Odyne system consists of:

- A 28 kilowatt-hour (kWh) battery pack that provided drive assist through power takeoff (PTO), stationary hydraulic power, and 12V auxiliary power along with an electric secondary A/C unit; and
- An on-board 3 kilowatt (kW) charger and charging port that utilized Level 2 electric vehicle supply equipment (EVSE, meaning a charging station).

SCE's EDS Group tested the vehicle from June through August 2018 at its vehicle testing labs in Pomona, California.

4.3.2 Scope of Work

SCE used a two-part test plan to assess the hybrid system's operation and reliability:

1. **Testing the vehicle's A/C capabilities** using thermocouples in conjunction with an Omega portable thermometer/data logger. This test consisted of four stages: 1) with no A/C and the vehicle completely off; 2) with the vehicle idling and the original OEM A/C unit on; 3) for a period to allow temperatures to reach normalization, and to create a baseline for the last stage; and 4) with the secondary A/C unit on, the OEM A/C unit off, and the vehicle idling.
2. **Testing the boom** while utilizing the external secondary battery unit. This test only required a tally counter and a qualified boom operator. To maintain the highest possible state-of-charge (SoC) on the battery pack, the vehicle was left plugged in and charging until the test was performed. With a high SoC, the vehicle was parked in an open area to perform the boom operation safely, and the external battery system was activated via ePTO. The operator performed sets of eight movements with the boom and recorded the SoC at 20-minute intervals. The test ended when the SoC reached 4% and the vehicle switched from electric mode to engine mode.

Figure 2. TA-60 Retrofitted With a Hybrid System (Medium-Duty VAPS Platform)

4.3.3 Procurement

The initial preferred platform for this subproject was a Class 5 Ford F550 9-foot flatbed – given SCE's plans at the time to purchase nearly 150 F550 flatbeds over the next several years – although other platforms were considered based on product availability. However, as previously noted, although several potential vendors were assessed for this subproject, none were capable of producing a PHEV or even an EV that met SCE's needs.

SCE ultimately decided to undertake the subproject with a TA-60 PHEV conversion using an Odyne system. Thus, SCE purchased an Altec TA-60 base truck built on a 2014 International 4300 chassis from its fleet of rented vehicles, and proceeded with the conversion by Odyne.

4.3.4 Results

SCE was able to successfully assess the reliability, functionality and energy consumption of the Odyne hybrid system upfitted to the TA-60 platform.

4.3.4.1 Reliability

Data showed the system operated consistently, with a repeatability within ±5%. On average, the system was able to consistently provide 63.8 cycles with the A/C off and 58.7 cycles with the A/C on. In terms of field usage, the system is anticipated to be able to reliably provide a full day's worth of operation on a single charge.

However, the charging system presented some inconsistencies while charging. In some cases, the charge would stop due to high ambient temperatures and would not continue charging although the temperature reached operating levels. It was not until the vehicle was disconnected and plugged back in when the charge picked back up. An increase in hotel loads (in this case, the fans that come on to cool off the battery during charging) could help prolong the life of the battery, if the vehicle is placed where hot weather is common.

4.3.4.2 Functionality

The system demonstrated flaws in the functionality of the secondary A/C unit. Specifically, the system provided low temperatures while in use; however, its ability to lower the cabin temperature was not efficient, because space constraints dictated its installation in a less-than-optimal position – under the seat, with the blowers pointing forward. This configuration kept the air confined to the lower half of the cabin.

4.3.4.2.1 Reliability and Functionality: Boom Operation

The activation and charging of the system was straightforward and user-friendly. The significantly lower noise level generated by the hybrid system, compared to a gas-powered boom, can contribute to a safer work environment. Furthermore, the system's fully electric operation can reduce both greenhouse gas and air-polluting emissions.

4.3.4.3 Energy Consumption

While the Odyne system is capable of storing 28 kWh, it also requires extra energy to maintain the battery's charge while at the same time regulating its temperature. In cases where the vehicle was left plugged in for more than a couple of days, the maintenance charge achieved a value close to the battery's charge capacity, and in some cases it even exceeded the energy required to charge the battery. Testing indicated irregularities in the system under certain conditions. For example, in some cases, the charge stopped due to high ambient temperatures and did not continue charging although the temperature reached operating levels. The charge only picked back up after the vehicle was disconnected and plugged back in.

4.3.5 Lessons Learned

The operational issues encountered during testing of the TA-60 vehicle retrofitted with a hybrid system are anticipated to be solvable, enabling fleet placement.

- **For the functionality of the secondary A/C unit:** This system can perform optimally if the unit’s vents can be rerouted to provide a means for the system to cool the cabin effectively.
- **For the high energy requirements for cooling the battery in hot weather:** This can be ameliorated by placing the vehicle in a more temperate location. For wider application, a more robust and efficient thermal management system is needed.

Overall, the hybrid system proved to be practical and easy to use. Testing showed that the electric A/C supplied or output air at adequate vent temperatures, while the system also provided enough boom time operation to translate into long actual field usage durations.

4.4 Small VAPS Power System

4.4.1 Overview

For this subproject, SCE purchased (separate from EPIC) 23 Altec AT-40 troubleman trucks built on Ford F550 platforms, equipped with the Altec Jobsite Energy Management System (JEMS) 4E4 Idle Mitigation System (IMS) using the ZeroRPM® lithium-ion battery-based system. The JEMS was:

- Intended to support all vehicle functions, including cabin cooling and boom operation, using on-board lithium-ion batteries instead of idling the engine at a jobsite; and
- Designed to be charged using shore power (plug-in electrical power), though it also can use the engine alternator.

A third-party remote data tracking system was installed on all 23 vehicles to determine the JEMS’ effectiveness in field operation. The EDS Group first performed functionality and fuel economy evaluation on one of the vehicles.

Figure 3. Front View of AT-40 Troubleman Truck Equipped With JEMS System

Figure 4. Rear View of AT-40 Troubleman Truck Equipped With JEMS System

4.4.2 Scope of Work

The subproject included four areas of work: 1) a performance evaluation of the converted truck assigned to the EDS Group; 2) testing of the charger for power quality; 3) cycle testing of the lithium-ion battery system to assess endurance; and 3) field data analysis of 22 trucks used by troublemen for daily duties.

4.4.3 EDS Performance Evaluation of Test Vehicle

The test plan included an evaluation of fuel economy and functionality, with the following elements:

- **Freeway and Urban Driving:** The truck was instrumented with a fuel flow measurement system, and then was driven on the freeway and on urban streets with all accessories on and off to determine basic fuel economy (per SCE's Vehicle Testing Procedure).
- **Stationary A/C:** With the battery fully charged, the vehicle was started and the JEMS activated. The engine shut down automatically. With the A/C compressor running constantly, and all lights and the radio turned on, the time the system ran until the engine started was recorded along with cabin, vent and ambient temperatures. This test's purpose was to determine the system's functionality, as well as its ability to maintain cabin temperature and chassis electrical support.

- **Troubleman Loop:** This test loop was driven with the JEMS off to obtain a baseline fuel consumption (per SCE's Vehicle Testing Procedure). It then was driven with the JEMS activated to determine the engine off time and fuel savings. The loop tests were performed with full accessories on (headlights, lights, radio, A/C set to max).
- **Battery Charging During Driving Impact on Fuel Economy:** The JEMS was activated and operated in a stationary mode until the engine automatically started and the engine alternator began to charge the JEMS battery. At this point, the vehicle was shut off to keep the battery discharged until the vehicle could be driven. During driving on a freeway test loop, the battery charged, allowing determination of the impact on fuel consumption.
- **Emissions Testing:** An emissions analyzer was placed on the test vehicle to determine the emissions impact of a certain period of idle-free time followed by starting and stopping the engine over and over, compared to a standard truck that idles at steady state.

All issues, repairs and modifications performed to the system over the test period were recorded.

4.4.3.1 Charger Power Quality Testing

The charger power quality testing was conducted on a prototype Altec JEMS 4E4 Idle Mitigation System (IMS). The IMS VAPS system was the same as the one delivered on the SCE AT-40 unit, but was mounted on a Dodge chassis that Altec loaned to SCE for an early evaluation. The JEMS 4E4 with the ZeroRPM lithium-ion battery-based system included an OEM-supplied on-board charging unit produced by the firm IOTA and intended for use with lead-acid batteries. SCE tested this as follows: With the batteries depleted to the point the engine turned on, they were charged using shore power, and the AC (alternating current) input (including current, voltage, energy and all power quality values) was monitored. The output of the charger to the batteries was not monitored, but the DC (direct current) input and output of each lithium-ion module were measured during A/C tests.

Because of significant problems encountered during testing, SCE requested an upgraded charger unit. (See Charger Power Quality Testing, Section 3.4.5.2, for more information about the initial charging complications.) Altec identified a customer-programmed Delta-Q charger, which SCE purchased. SCE then performed back-to-back charge and discharge testing to compare the Delta-Q unit with the OEM IOTA brand charger using the ZeroRPM battery system installed on one of the Ford F550 vehicles.

4.4.3.2 Battery System Endurance Testing

Upon receipt of the Altec JEMS-equipped troubleman trucks, SCE discovered multiple issues with the system, and learned that some batteries already had been replaced. Because Altec indicated they had not performed any long-term testing, SCE acquired separately the center component – the JEMS 4A, which contains the lithium-ion battery-based system and switching contactors (which are used to connect and disconnect the batteries) – for an endurance test program to evaluate the potential durability of the system.

Specifically, over the course of a six-month period, the JEMS was charged and discharged 618 times following a simulated discharge and charge cycle using a battery cycler. Four Reference Performance Tests (RPTs) also were performed to determine if any battery degradation had occurred.

4.4.3.3 Field Data Analysis

In addition to the data gathered using the remote tracking system installed on the Altec AT-40 troubleman trucks, user feedback was incorporated into the analysis of the vehicles' performance.

Figure 5. JEMS Components in AT-40 PHEV Test Vehicle Truck Bed

4.4.4 Procurement

See Overview, Section 4.4.1, for a description of the vehicles purchased for this subproject.

4.4.5 Results

For the first six to eight months after SCE received the first production run of the Altec troubleman trucks equipped with the JEMS IMS, the vehicles experienced significant system issues and component failures. Altec attributed many of the failures to early manufacturing challenges and performed two major system updates on the trucks, including both hardware and software changes.

In addition, SCE's EDS Group worked with Altec to verify system performance on the one test vehicle, and with Altec and SCE troublemen to identify and rectify issues encountered with the vehicles being used in the field. Nonetheless, the functionality and production problems prevented the EDS Group from completing test procedures on the vehicle assigned to them.

4.4.5.1 EDS Performance Evaluation of Test Vehicle

- The JEMS run times using the electric A/C were entirely dependent on ambient air temperatures. The engine off time was anywhere between 42-140 minutes. Given this variation, it was not possible to provide fixed-result data for engine off times and fuel savings on the Troubleman Loop.
- The truck consumed 0.51 gallons per hour (GPH) of diesel when idling with full loads on, 0.36 GPH with all loads off, and 0.55 GPH when idling with full loads on and charging the JEMS battery. Given the range of the JEMS operating times, the system potentially could save up to 1.2 gallons of diesel per charge, or as little as 0.4 gallons, depending on air temperature and battery SoC.
- The JEMS was able to charge with shore power, but also from the engine when the JEMS was depleted. Freeway drives performed with the engine charging the JEMS battery did not show any measurable fuel economy difference when the JEMS battery was not being charged.
- The JEMS produced fewer nitrogen oxide (NOx) air polluting emissions over the course of a 114-minute test with the engine cycling on three times compared to running the engine constantly. Extrapolating this data, the JEMS operation reduced NOx emissions by 12% versus the emissions generated by the engine running constantly over the test duration. The on and off engine cycling did not result in increased emissions.

After the production issues were resolved, the test vehicle had the same functionality as a conventional vehicle, including the electric A/C working effectively in up to 100F ambient air temperature, with the additional benefit of the engine being off when in JEMS mode. No negative operating impacts were identified when the system was working correctly with a well-trained user.

4.4.5.2 Charger Power Quality Testing

In the initial testing, the power quality of the IOTA marine battery charger (which the JEMS 4 uses to charge the lithium-ion batteries) did not meet the Society of Automotive Engineers (SAE) J2894 (Power Quality Requirements for Plug-In Electric Vehicle

Chargers). This particular charger had a current total harmonic distortion (iTHD) of 105% at full power. In contrast, the SAE J2894 recommended charging practices specify an iTHD of 10% or less. Figure 6. Harmonic Distortion Profile shows the iTHD over the full power range, with the red line marking 10%.

The charger also did not comply with California Battery Charging Standards. The maintenance charge was 51 watts (W), which is very high and can result in more energy being wasted than used to charge the batteries. The batteries required 2.2-2.4 kWh to charge, but the total energy drawn from the grid was as high as 6.8 kWh due to the high maintenance load.

Test Info	**Maintenance Test**
Test Date	**2/26/2016**
Nominal Voltage (V)	120
Energy Consumption (AC kWh), Bulk Charge	2.206
Energy Consumption (AC kWh), Total Charge	5.629
Energy Consumption (AC kWh), Maintenance	3.423
Duration (h:mm), Bulk Charge	2:36
Duration (h:mm),Total Charge	69:23
Duration (hr:min), Maintenance Charge	66:47
Average Maintenance Charge Power (W)	51
Minimum Line-to-Line Voltage (V)	117.52
Maximum Line-to-Line Voltage (V)	124.72

Table 1. Battery Test Conditions

Power Quality Parameters	Maximum Power	Minimum Power	Acceptable Ranges[6]
Voltage A-B (V)	119.48	122.63	
Current (A)	11.674	0.9869	≤ 12A
Frequency (Hz)	59.99	59.99	
Total Active Power (kW)	0.8941	0.05131	
Total Reactive Power (kVAR)	-0.2341	-0.0027	
Total Apparent Power (kVA)	1.395	0.12128	
True Power Factor	-0.6409	-0.4231	≥ 0.95
Total Voltage THD (%)	4.379	1.73	
Total Current THD (%)	105.05	215.13	≤10%

Table 2. Power Quality Test Results

After the main charge was complete, the JEMS 4 kept pulling power until it was unplugged. As indicated by the test shown in Table 1. Battery Test Conditions and Table 2. Power Quality Test Results, this was an average of 51 watts, which used an additional 3.4 AC kWh over 66 hours and 47 minutes after the bulk of the charging had finished. The bulk charge only used 2.2 AC kWh.

6 References the Society of Automotive Engineers' (SAE) J2894/1 Power Quality Requirements for Plug-in Electric Vehicles.

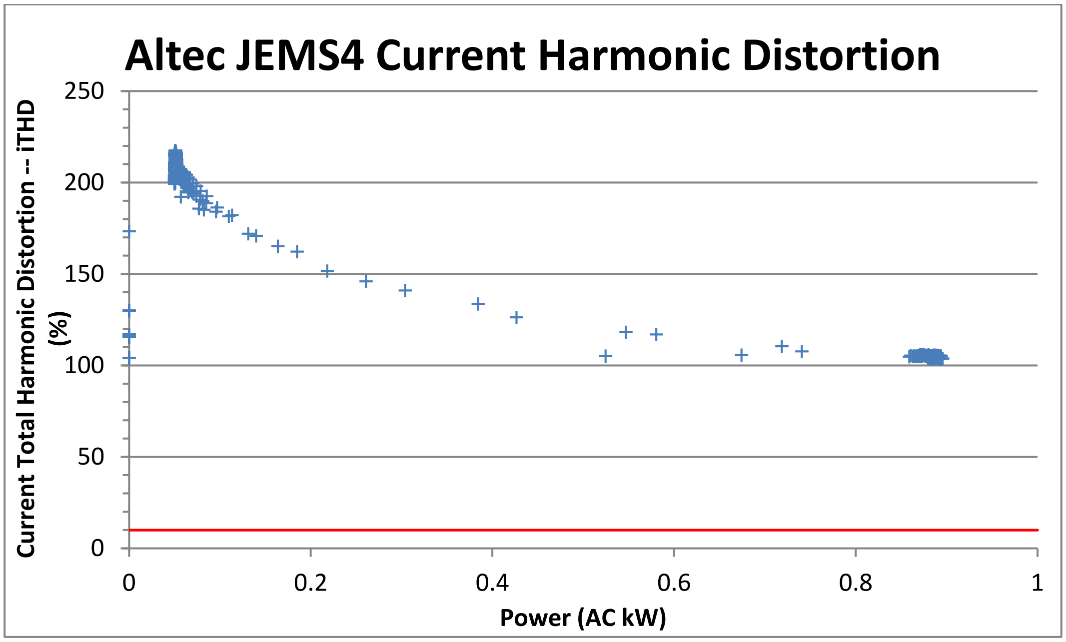

Figure 6. Harmonic Distortion Profile

In addition, one major shortcoming is how the battery control system manages energy flow. During discharge mode, only one module supports all 12-volt (V) chassis loads, while the two other modules support just the compressor. Without an active DC/DC converter to balance the energy of the three modules, the electric A/C run time is primarily dependent on the 12V chassis loads and 12V module condition.

The Delta-Q charger SCE subsequently tested produced much better results. Certified as compliant with California Title 20 standards, the charger passed all SAE J2984 power quality requirements, and its power quality was much better than that of the IOTA. Specifically, the Delta-Q had a power factor of 0.99, while the IOTA reached 0.69 at best. (Power factor is related to how much useful work is obtained from a system.) In addition, the Delta-Q unit was able to perform the bulk charge to the batteries in less than eight hours using 3.61 kWh AC, while the IOTA required 15 hours and used 3.79 kWh AC. The IOTA unit charged the batteries to 13.5V; the Delta-Q charged the batteries to 14.4V but showed no increase in system run time. The maintenance power of both units was approximately 65 W, but the Delta-Q charger has a control input to shut the unit off, which was not implemented during testing.

4.4.5.3 Battery System Endurance Testing

The system tested included the core ZeroRPM electric A/C unit with a built-in 12 V/120 VAC (Volts Alternating Current) charger, a separate 24 VDC (Volts Direct Current) electric motor-driven hydraulic subsystem, Altec's Power Distribution Module Auxiliary (PDMA) controller, export power inverter and control display. The truck came with two OEM lead-acid batteries, which are disconnected from the 12 V chassis via contactors when the IMS system is active under various situations. Key results/conclusions from this testing indicated:

- The two modules used to create 24 VDC showed negligible capacity degradation, which was not unexpected based on system design. The module used for 12 VDC did show measurable degradation as it was typically discharged to a very low SoC, and the capacity dropped from 101% to 97% over time. However, the system did not experience any component failures, such as contactors, during the testing.
- Because the 12 V module directly impacts idle mitigation time, degradation over time is expected to result in lower idle mitigation durations. There are too many variables that affect idle mitigation time to directly project fuel savings impacts. However, assuming one full cycle per day over five workdays each week, it is projected that the idle mitigation time could drop by 10% after five years. Using the test results, this could translate to 4-14 minutes of reduced idle mitigation time per single full charge to depletion from 44-114 minutes, the range of run times during the evaluation of all of the vehicles.
- The 600-plus cycles the system ran translate to approximately 2.5 years of operation. The contactors did not fail or show any sign of failure, although they were not disassembled and inspected for signs of damage. No other internal component experienced any failures or issues during testing.

4.4.5.4 Field Data Analysis

Multiple SCE troublemen who used the vehicles in the field indicated the system operation was highly inconsistent. In some cases, they had to restart the vehicle multiple times and use various procedures to get the ePTO or standard PTO to operate. The EDS Group also experienced similar issues with intermittent PTO operation during evaluation of its test vehicle.

Given this feedback, the following are data results/broad conclusions based on troublemen's field use of 22 JEMS-equipped trucks for a variety of applications:

- The miles driven during the data collection period ranged from 8,600 to 25,900, while the total accumulated miles ranged from 24,000 to 73,000. The engine idle time varied from 145 hours to 540 hours, and IMS times varied from 49 to 415 hours.
- The JEMS IMS total operation times ranged from 50% to 100% of the total engine idle time, meaning that for every hour of engine idle, the JEMS supported the vehicle for 30-60 minutes with no engine idle.

- IMS operating times had no direct correlation to shore charging times; thus active engine charging of the batteries was always occurring. Vehicles with minimal shore charging times had equal or higher IMS/engine idle ratios than vehicles with a high number of shore plug-ins. The IMS operating times were more proportional to vehicle run and idle hours because of the engine charging the batteries.
- Limited lab testing was unable to measure above the limit of uncertainty the fuel economy impact of driving the vehicle on the highway while charging the JEMS batteries. It would be incorrect to assume that the vehicles that did not have shore charging always saved 0.4-0.5 GPH for every hour of IMS operation. (Per lab testing, a typical AT-40 vehicle consumed this amount of diesel when idling.)
- Based on the testing, the exact impact on battery life of using only vehicle engine charging is unknown because 1) batteries are unlikely to be charged to 100%; 2) batteries may not be able to perform cell balancing (which, according to Altec, is important to maintain battery life); and 3) the number of charge/discharge cycles per day may vary based on the application. Lack of proper battery maintenance and an increased number of charge/discharge cycles could reduce the battery's effectiveness over time, thus impacting system payback.

4.4.6 Lessons Learned

The data indicated that the troubleman vehicle represents a good candidate for idle mitigation, as the standard field trucks operate more than twice as much time in idle mode than in driving mode.

No negative operating impacts were identified during testing when the JEMS was working correctly with operation by a well-trained user. However, the trucks equipped with the JEMS were not intuitive to utilize and required a certain level of user interaction to function properly. Whether due to system failures, system operation, user expectations or a combination of all three, the initial user acceptance of vehicles equipped with JEMS has been very low to date. The system definitely needs further refinement with its interface, as well as extensive training for users, to improve this acceptance rate.

Key operational lessons learned and recommendations include:

- Future production launches need to include: 1) performing functionality testing before field deployment, 2) initially placing fewer units in the field, and 3) if possible, finding users interested in supporting the product.
- Any future JEMS need to include a hard-wired manual bypass that allows the engine-powered PTO activation. Because the current JEMS does not have a primary bypass system, in multiple scenarios in which a JEMS failed during testing, it rendered the PTO function inoperable.
- Each new model year vehicle with JEMS needs to be validated before fielding large numbers of them. This can address the fact that as newer vehicles come to market with various levels of engine start/stop technology, integrating JEMS likely will present a significant engineering task.

- Although testing indicated that IMS operating times had no direct correlation to shore charging times, previous testing on larger energy systems have shown a direct correlation between shore charge and fuel savings. Therefore, failing to 1) set a policy to require or at least encourage shore charging; 2) create policies to encourage users to support the technology; and 3) use these vehicles as an opportunity to install additional charging infrastructure likely would create a significant negative effect on IMS adoption and functional impact as further vehicles are acquired.
- Because the initial IOTA charger did not meet power quality requirements, SCE was interested in finding a more efficient replacement for possible future orders. The Delta-Q charger subsequently tested met all power quality requirements, and it has a California Title 24 certification. Unless additional information is provided to justify maintaining the batteries at 14.4 V, the charger needs to be programmed to shut off when the batteries reach this level in order to minimize energy consumption. With this addition, the EDS Group recommends the Delta-Q as an acceptable charger for the JEMS system.
- To optimize system payback, it is necessary not only to identify applications with high idle times, but also to make sure the system is maintained so it lasts the expected lifetime without the high cost of battery failure and system breakdown. It is recommended to find applications where the vehicle is returned to a service center every evening to ensure the battery is charged to 100%, thus limiting charge/discharge cycles in the field.
- It also is recommended that once per year a sample of fielded JEMS vehicles are cycled and the run times and ambient temperatures recorded. If the idle mitigation times lower significantly, SCE needs to approach Altec to discuss replacing the 12 V module under the battery warranty agreement.

Overall, the core concept of JEMS usage with troubleman trucks tested soundly, and – with the proper refinements and operator training – could present a potentially viable option for SCE for idle mitigation in field operations.

4.5 Medium VAPS Power System

4.5.1 Overview

The Medium VAPS System subproject assessed the use of an Envoltz trailer-mounted fully electric underground cable puller powered by an EnerDel lithium-ion battery. The puller provided fully electric-driven jobsite equipment capable of operating for a full workday and recharging off of grid power.

Cable pullers are used extensively in the utility industry and are key components of the industry's fleet. A unique feature of the Envoltz unit is its ability to precisely wind and unwind the cable spool, using a propriety system to keep the cable perfectly laid on the spool. The Envoltz unit also includes a detachable touch screen remote control panel that allows the user to stand up to 20 feet from the unit.

Figure 7. Envoltz Scorpion 12K Cable Puller During Turnkey Inspection

4.6 Scope of Work

In 2016, SCE tested the Scorpion 8K, Envoltz' first-generation electric underground cable puller, using the following controlled tests at the SCE Electric Vehicle Technical Center in Pomona:

- **Varied Load and Speed Testing:** Setting the unit to pull against a wire stringer at three speeds per various wire stringer fixed loads to determine basic functionality, with the last test run performed until the battery was depleted and the unit shut down automatically.
- **Level 1 Charger Testing:** Charging the unit via 120 VAC shore power and measuring various parameters.
- **Constant Full Load and Speed Testing**: Running the unit at full load and speed until the battery was depleted and the unit shut down automatically.
- **Depleted Battery Pulling Testing:** Testing the puller's maximum speed and load capability, following complete battery depletion, using a 120 VAC portable generator power supply.
- **Level 2 Charger Testing:** Charging the unit via a 240 Level 2 EV charger and measuring various parameters.

In addition to the lab testing, the Scorpion 8K was taken to two separate SCE jobsites for field crews to determine its effectiveness under real-world conditions.

Based on the results of using the Scorpion 8K in this EPIC VAPS project, SCE decided to purchase the Envoltz Scorpion 12K, which features a larger battery pack and two AC motors instead of one for field deployment.

Functionality testing of the 12K at SCE's Electric Vehicle Technical Center included:

- **Pull Testing**: Connecting the puller to a similar (but diesel engine-powered) puller (the V-Groove) and pulling back and forth at various loads and speeds.
- **Charging Testing:** Testing for charging efficiency and power quality (with the same hardware used to evaluate the Scorpion 8K).
- **Battery Performance Testing:** Charging and discharging the battery to determine if any battery degradation occurred.

4.6.1 Procurement

SCE initially evaluated the Envoltz Scorpion 8K, touted by the vendor as the only all-electric underground puller in the industry. The unit is capable of pulling loads of up to 8,000 lbs. at 150 feet per minute (fpm), is powered by an EnerDel 20 kWh advanced lithium-ion battery pack, and has one 50-horsepower (hp) AC motor. SCE's TSD believed that this unit might be a valuable field tool, so the EDS Group invited Envoltz to bring the unit onsite for two days of testing to confirm basic functionality and safe operation. SCE also used the unit for two jobsite pull demonstrations.

Based on the successful testing experiences with the Scorpion 8K, SCE decided to purchase the larger Scorpion 12K, which includes a 29 kWh battery pack and two 50 hp AC motors instead of one, and is rated to pull up to 12,000 lbs. at 150 fpm.

The first Scorpion 12K unit was delivered to SCE on September 6, 2017. After the battery and drive system passed all testing criteria, the unit was turned over to TSD for final modifications and field deployment.

4.6.2 Results

4.6.2.1 Scorpion 8K

In lab testing, the proprietary control system to precisely wrap the cable onto the spool worked flawlessly. In addition, the maximum preset load feature worked correctly and stopped the pull when the line tension went over the limit. Other findings included that the unit:

- Was able to pull at various loads up to 4,000 lbs. (the maximum rating of the wire stringer it pulled against) at various speeds up to 150 fpm without issue.
- Was able to pull 1,500 feet of cable at 3,700 lbs. at 150 fpm seven times on a single battery charge. (TSD indicated that a typical workday would consist of six pulls at this level.)
- Derated itself as the battery capacity neared zero and stopped itself when the SoC reached zero.

- Was able to demonstrate limited operation when the battery was fully depleted and the unit was operating on a line truck-mounted generator, and also successfully charged on the generator.
- Showed good charge quality operating on a 120 VAC 20-amp circuit.
- Was not able to charge using a Level 2 (240 VAC) EVSE due to a faulty communication module inside the unit (but this function later was demonstrated at an SCE service center).

In three days of jobsite field demonstrations, the unit was able to successfully pull up to 1,900 feet of 3 kilovolt (kV) cable while using up to 17 percent of the battery energy.

Overall, the unit performed all required functions safely without any issues.

4.6.2.2 Scorpion 12K

The Scorpion 12K was able to pull at various loads up to 10,000 lbs.[7] and at speeds up to 150 fpm in accordance to the unit specification without issues related to the battery or drive system. The unit performed at full capacity down to a SoC of 4%, and showed good charger power quality operating on a 240 VAC circuit using an EVSE. The battery had a capacity of 25.3 kWh, which exceeded the vendor's specifications.

Overall, the unit performed all required functions safely with limited issues, three of which only required simply fixes. The last issue occurred due to a change in the type of cable specified by SCE. As a result, the unit did not perform as necessary when automatically paying out the cable (a mode that allows the user to push the cable off of the drum). Because of the differences between the Scorpion 12K standard round cable and SCE's required multi-strand cable, the cable did not sit smoothly inside the rounded sheave (pulley wheel), and thus slipped and slackened on the drum when the unit operated in the automatic payout mode.

To rectify this, Envoltz tested alternative sheave groove shapes and updated the two remaining cable pullers ordered by SCE to resolve the issue before shipment.

In summary, the Scorpion 12K battery and drive system passed all SCE testing criteria, ensuring the unit was ready for field deployment.

4.6.3 Lessons Learned

The following lessons learned indicate the potential value of the Envoltz Scorpion 12K all-electric underground puller in jobsite use by SCE:

- Results indicated that the Scorpion 12K's energy level is anticipated to be sufficient for it to perform at a typical jobsite for two to four days without charging the unit.

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[7] The Scorpion 12K was factory rated to be able pull at various loads up to 12,000 lbs. In accordance with the Transportation Services Department and Work Methods specification, the software derated the maximum pull to 10,000 lbs. and the system was tested to operate at that level.

Although the procedure would be to charge the unit daily, this high energy capacity indicates that the unit would be able to perform daily for years even when the battery capacity begins to decrease.
- While it was difficult during testing for field personnel to communicate when using the diesel-powered V-Groove puller due to loud engine noise, they were able to communicate easily next to the Scorpion unit. This would provide a significant advantage for field crews in terms of safety and efficiency.

Based on testing, the Scorpion 12K would provide SCE with a new option for all-electric underground cable pulling.

4.7 Large VAPS System

4.7.1 Overview

For the Large VAPS System work, SCE selected and evaluated a portable, trailer-mounted VAPS battery unit designed to replace traditional diesel-fueled generators. The project plan was to electrify the most energy-intensive stationary fleet job applications that currently use heavy-duty diesel vehicles and stationary engine generators.

Due to the more advanced nature of the product assessed and the potential applications for its use in the fleet, this system was evaluated differently from the rest of the VAPS Project in that it would not directly lead to a fleet placement.

4.7.2 Scope of Work

After the unit was received and inspected, it was set up and tested under simplified acceptance test protocols, and then subject to full performance testing. The setup for the system at SCE's Electric Vehicle Technical Center in Pomona included both charge and discharge controls. One cycle was performed daily, with charge and discharge starting at the same time each day. Limitations identified in test cycling proved to be factors that prevented a fleet trial.

4.7.3 Procurement

SCE completed detailed specifications for the Large VAPS System in February 2017. After an extensive market search was performed, FreeWire Technologies, Inc. was determined to be the only supplier for a large VAPS system capable of meeting all of SCE's requirements. The system was mounted to a trailer – the FreeWire Mobi® Gen TW product offering. In addition, the unit was supplied with a second-use Nissan LEAF EV battery package and was expected to output 40 kWh.

The FreeWire Mobi Gen was delivered to SCE in April 2018. It is important to note this unit was several generations behind what FreeWire now offers, and FreeWire no longer provides used EV batteries in its devices.

Figure 8. The Large VAPS FreeWire Technologies Mobi Gen as Received and Inspected

4.7.4 Results

Upon delivery, the FreeWire Mobi Gen appeared to generally comply with SCE's specifications for the use cases envisioned. However, the results of lab testing did not meet minimum SCE requirements to proceed to field trials.

Power quality results from the charger (for the Nissan LEAF EV batteries) were much lower than the minimum requirements of the Society of Automotive Engineers (SAE) J2894 (Power Quality Requirements for Plug-In Electric Vehicle Chargers). As such, SCE would not use the system in its fleet or recommend it to customers. In addition, the availability of the system was marred by inadequate auxiliary battery control, and the battery capacity tested too low.

The inadequate auxiliary battery control created operational issues to the point where the batteries completely discharged and could not be recovered. As a result, the Mobi Gen would not turn on after sitting inactive for just a few days. For a potential solution, SCE fitted the Mobi Gen with individual Battery Tender® chargers, but these had to be constantly connected to power to maintain the auxiliary batteries.

The Mobi Gen system was relatively primitive at the time of SCE's receipt and evaluation, as FreeWire had just begun selling and shipping the technology. SCE plans to further address the results of testing with FreeWire in the future.

4.7.5 Lessons Learned

This project did not progress to the planned field data collection due to the issues identified. In terms of reliability and availability of the Mobi Gen system due to the auxiliary battery control issues, any special field test would require special handling by SCE engineers. It may be possible to do this in the future – such as to see if the system could power stationary loads for a splice lab or underground inspection function – but the system currently is not reliable enough to deploy on its own. However, SCE did learn that changes need to be made to the core system to ensure performance in the fleet. FreeWire has made subsequent changes to the Mobi Gen system that are anticipated to help, including the elimination of second-use EV batteries, which is anticipated to provide higher capacity availability and improved performance.

Overall, the Large VAPS System has an envisioned usage value in a variety of potential applications. In fact, with heightened interest in the ability of VAPS to provide backup power during a Public Safety Power Shutoff (PSPS) – a temporary power shutoff during high-fire-risk conditions to prevent the electric system from becoming an ignition source – more options now are available to explore. SCE intends to continue looking at improvements made by FreeWire, as well as at products from other vendors offering similar systems in the future.

5 Value Proposition

The VAPS Project was undertaken to evaluate the benefits and assess the impacts of deploying VAPS technology, which can contribute to meeting SCE's fleet electrification goals by using a multifaceted approach to cost-effectively electrify both SCE's fleet vehicles and jobsites.

The daily duty cycle for utility work vehicles involves a significant amount of engine idling to support stationary vehicle operations (ranging from safety lights, to hydraulic loads, to computers and more). Use of electric-powered technology for vehicle and stationary uses could provide significant value by:

- Reducing fuel consumption and thus costs,
- Lowering SCE's carbon footprint,
- Lessening wear on engines,
- Improving utility worker and public safety due to quieter operations and fewer polluting emissions,
- Contributing to training efforts while educating employees about the advantages of electrification at work locations, and
- Providing a lower-cost option for fleet electrification compared to the purchase of new vehicles.

See VAPS Subprojects, Section 4, for a summary of the subprojects and results that address the benefits and impacts of the technologies evaluated.

6 Metrics

The following metrics were identified for this project and evaluated during project work based on the value proposition presented by deployment and use of PHEVs, BEVs, and portable, electric energy storage systems installed on existing and new fleet vehicles. (See Value Proposition, Section 5, for more details.) Also see the results for all of the subprojects in VAPS Subprojects, Section 4, for data from project testing on these metrics:

- **Economic Benefits:** Maintain/reduce operations and maintenance costs and provide other non-energy economic benefits
- **Environmental Benefits:** Greenhouse gas and criteria air pollution emissions reductions
- **Safety, Power Quality, and Reliability:** Public and utility worker safety improvement and hazard exposure reduction

One additional metric was indicated for this project:

- **Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy**: Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid-electric vehicles, and thermal-storage air conditioning (PU Code § 8360)

Nearly all of the VAPS subprojects resulted in the identification of barriers or other issues affecting wider-spread deployment of technologies to electrify SCE's fleet and jobsites. See the Results and Lessons Learned subsections for the subprojects in VAPS Subprojects, Section 4, for more details. SCE is committed to continuing to address these issues and conducting further projects to increase use of electrification and, in the process, do its part to contribute to California's aggressive decarbonization goals.

7 Stakeholder Engagement

Following are the SCE stakeholders involved in the VAPS Project:

Stakeholder Organization	Interest in the Project
Transmission & Distribution (T&D), Construction Methods	T&D aims to maximize the safety of utility crews and the public, while lowering vehicle fuel costs, by utilizing jobsite vehicle technologies that produce less noise, fewer polluting emissions and less engine idle.
Transportation Services Department (TSD), including TSD Fleet Asset Management and TSD Fleet Planning and Strategy	TSD needs proven, reliable options to make practical and fiscally responsible purchases that meet SCE's fleet electric transportation goals and achieve the benefits provided by electrification.

7.1.1 Technology/Knowledge Transfer

SCE's Grid Technology and Modernization Group worked closely and maintained open lines of communication with the SCE transportation electrification end-use organizations (noted above) and with the various VAPS Project vendors. This enabled the exchange of information about VAPS technologies, their features and capabilities. For future projects, this cooperative approach will result in efficient, cost-effective procurement and deployment of technologies that meet SCE's needs and contribute to electrifying its fleet over a wide range of vehicle types and job functions using a variety of platforms

List of Acronyms

AC	Alternating Current
A/C	Air Conditioning
AQMD	Air Quality Management District
BEV	Battery-Electric Vehicle
CPUC	California Public Utilities Commission
DC	Direct Current
DTC	Diagnostic Trouble Code
ECU	Engine Control Unit
EDI	Efficient Drivetrains, Inc.
EDS	Electric Drive Systems (Group, SCE)
EEI	Edison Electric Institute
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute
ePTO	Electronic Power Takeoff
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
fpm	Feet Per Minute
GPH	Gallons Per Hour
Hp	Horsepower
IMS	Idle Mitigation System
iTHD	Current Total Harmonic Distortion
JEMS	Jobsite Energy Management System
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-Hour
NOx	Nitrogen Oxides
OEM	Original Equipment Manufacturer
EV	Electric Vehicle
PDMA	Power Distribution Module Auxiliary
PHEV	Plug-in Hybrid Vehicle
PSPS	Public Safety Power Shutoff
PTO	Power Takeoff
RPT	Reference Performance Test
SAE	Society of Automotive Engineers
SCE	Southern California Edison
SEPA	Smart Electric Power Alliance

SoC	State-of-Charge
T&D	Transmission & Distribution
TSD	Transportation Services Department
V	Volts
VAPS	Vehicle Auxiliary Power System
VAC	Volts Alternating Current
VDC	Volts Direct Current
W	Watt

Appendix D

Regulatory Mandates: Submetering Enablement Demonstration - Phase 2

Final Project Report

Advanced Technology
IIM-14-0070 – Regulatory Mandates: Submetering Enablement Demonstration Phase 2 Final Project Report

Developed by

SCE Transmission & Distribution, Grid Technology and Modernization

December 2019

Acknowledgments

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1. Executive Summary

The California Public Utilities Commission (CPUC) issued a decision[1] in 2013 directing the state's three investor-owned utilities (IOUs), including Southern California Edison (SCE), to implement a two-phased pilot using Electric Program Investment Charge (EPIC) funds.

The Submetering Enablement Demonstration Phase 2 Pilot was available to a maximum of 500 eligible plug-in electric vehicle (PEV) submeters within SCE's service territory beginning January 16, 2017, and ending April 30, 2018. SCE enrolled 151 residential, single customer-of-record submeters.

Three Submeter Meter Data Management Agents (Submeter MDMAs) were responsible for enrolling customers into the Phase 2 Pilot; completing and signing the Customer Enrollment Agreements (CEAs) with the customers and submitting them to the IOUs; providing customers with an approved charging station with an embedded submeter; and collecting, formatting and transferring customer submeter data to the IOUs for billing purposes.

MDMA formatting errors, hardware accuracy issues and server maintenance resulted in billing problems, and the manual processes used during the Pilot created challenges for SCE, the MDMA and customers.

However, when a third-party evaluator (3PE), Nexant, was contracted to conduct a customer satisfaction survey, it found that 91% of respondents said they were extremely or somewhat satisfied with their overall submetering service during Phase 2.

In addition to helping meet regulatory requirements, the pilot phases supported "smart charging" components associated with the integration of electric transportation in a smart grid environment, California's zero-emission vehicle (ZEV) goals, and lower customer EV charging costs.

2. Project Summary

2.1 Phase 2 Pilot Background

On November 14, 2013, the CPUC issued a revised Proposed Decision Modifying the Requirements for the Development of a Plug-In Electric Vehicle Submetering Protocol set forth in D.11-07-029. The state's IOUs – SCE, Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E) – were directed to implement a two-phased pilot beginning in May 2014, with funding for both phases provided through EPIC.

EPIC aims to fund applied research and development, technology demonstrations and deployments, and market facilitation programs for the benefit of the electricity ratepayers of SCE and the state's other investor-owned utilities. The utilities are limited to demonstrations, which focus on advancing the grid.

Based on Figure 1, the Phase 2 Pilot concentrated on the Customer-Focused Products and Services Enablement area, with Electric Transportation as a Key Driver and Policy.

[1] Decision (D.) 11-07-029.

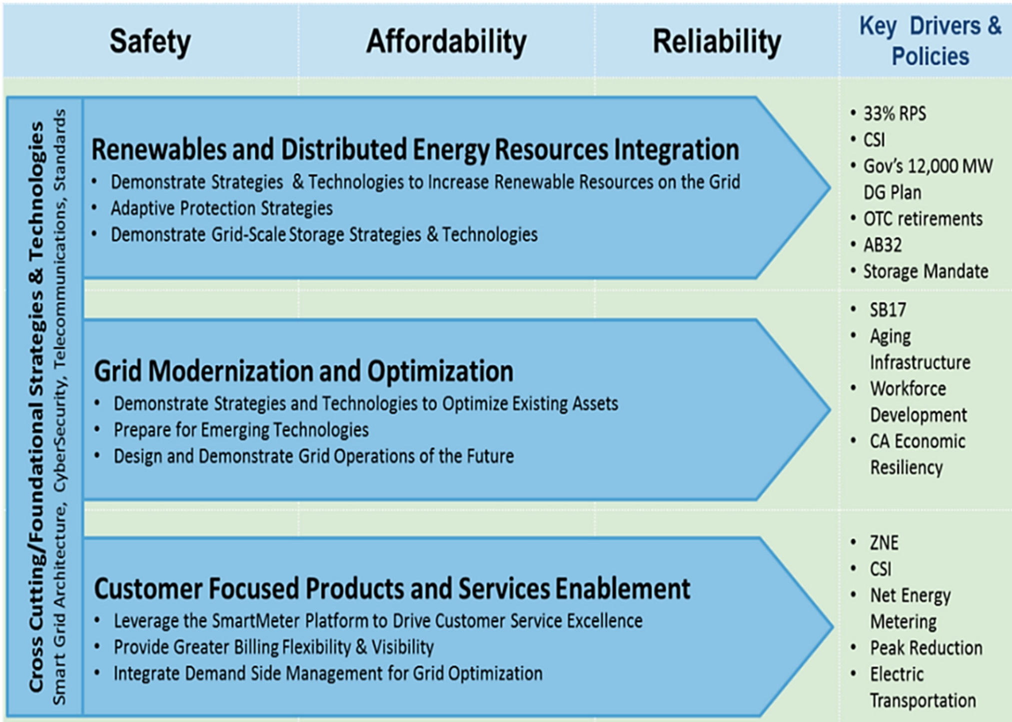

Figure 1. Joint Utilities EPIC Framework

As previously noted, the Phase 2 Pilot was available to a maximum of 500 eligible PEV submeters within SCE's service territory. All residential and commercial customers could participate except streetlight customers and those taking Direct Access, Electric Service Provider, and Community Aggregation services.

Eligible customers enrolled in the Phase 2 Pilot charged a plug-in electric vehicle measured by a dedicated submeter (submeter load) connected to the same interval data recorder-type meter that registers the customer's primary load. The submeter load was manually subtracted from the customer's primary meter load and billed, each month, on SCE's TOU (Time-of-Use)-EV-1 rate schedule. The remaining primary meter load was billed on the customer's current primary meter rate. Examples of residential and commercial EV charging are shown in Figures 2 and 3, respectively.

Figure 2. Residential EV Charging Example

Figure 3. Commercial EV Charging Example

2.2 Phase 2 Pilot Process

The Submeter MDMA registration for the Phase 2 Pilot included a two-step process:

Step 1:

All Submeter MDMAs that wanted to participate in the Phase 2 Pilot needed to complete and submit the Submeter MDMA Registration Agreement (RA) (see below) to the CPUC's Energy Division (ED) by September 15, 2016 to receive preliminary approval to take part.

Step 2:

Final approval to act as a Submeter MDMA in each IOU's territory was granted by the respective IOU to Submeter MDMAs that satisfied the requirements established in the RA, and Attachment 1 (Performance Standards for Metering and Meter Data Management Agents) and Attachment 2 (Data Reporting and Transfer Requirements) (see below).

PDF
Form 14-976
10.28.16 FINAL.pdf

Six potential Submeter MDMAs participated for all or part of the development of the Phase 2 Pilot requirements from February 2016 to May 2016. Five companies applied. Three met the requirements and were approved to provide Submeter MDMA services to SCE during the Phase 2 Pilot. The identity of the MDMAs is not revealed to protect their privacy, so they are referred to as MDMA 1, MDMA 2 and MDMA 3.

The three Submeter MDMAs were issued Purchase Orders (POs) to enable SCE to pay them $210 for each customer enrolled and $17.50/billing cycle/submeter for providing SCE with EV submeter usage data.

The Submeter MDMAs' role in single and multiple customers-of-record scenarios and the submeter data collection and billing processes are shown respectively in Figures 4, 5 and 6, respectively.

Single Customer-of-Record Scenario

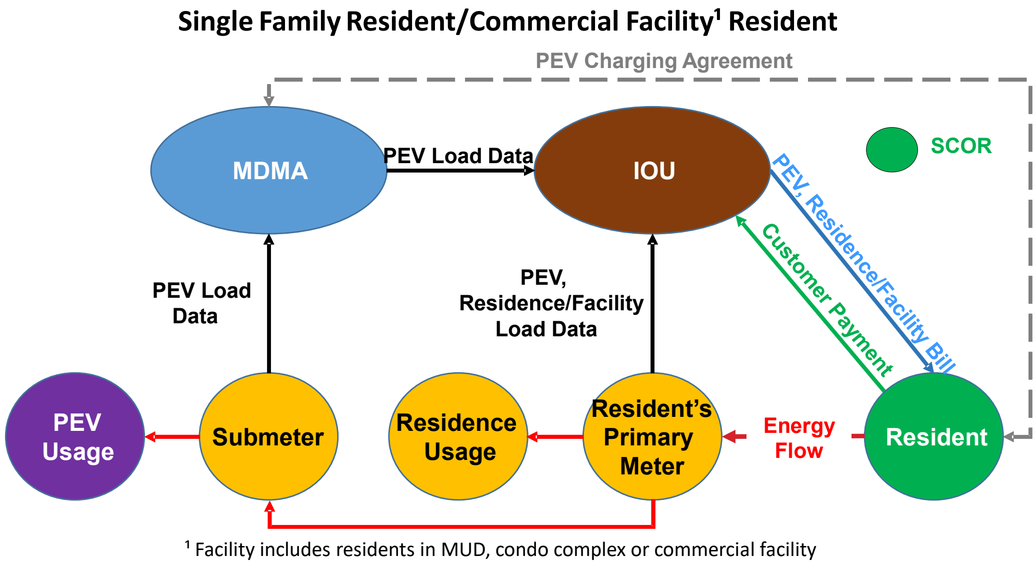

Figure 4. Single Customer-of-Record Scenario

Multiple Customer-of-Record Scenario

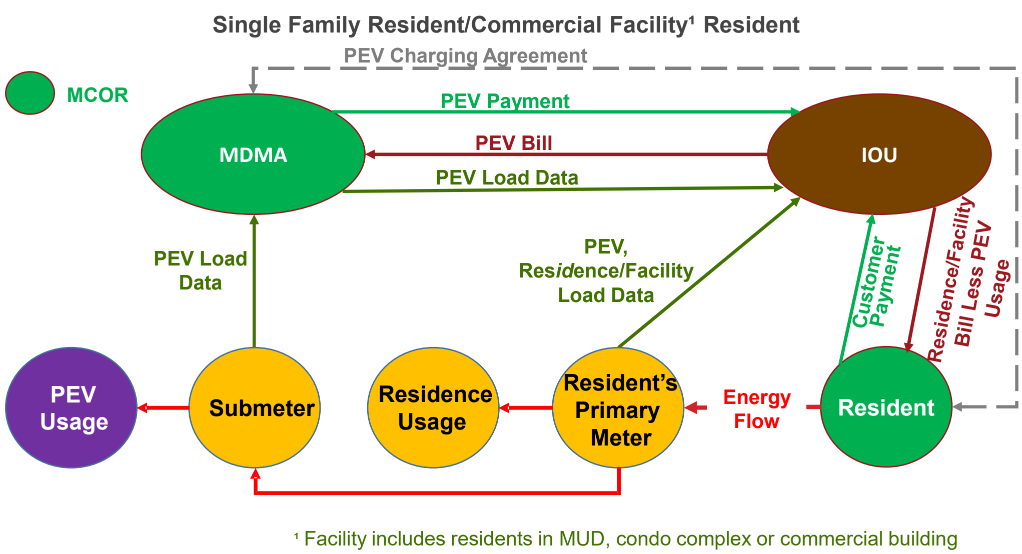

Figure 5. Multiple Customer-of-Record Scenario

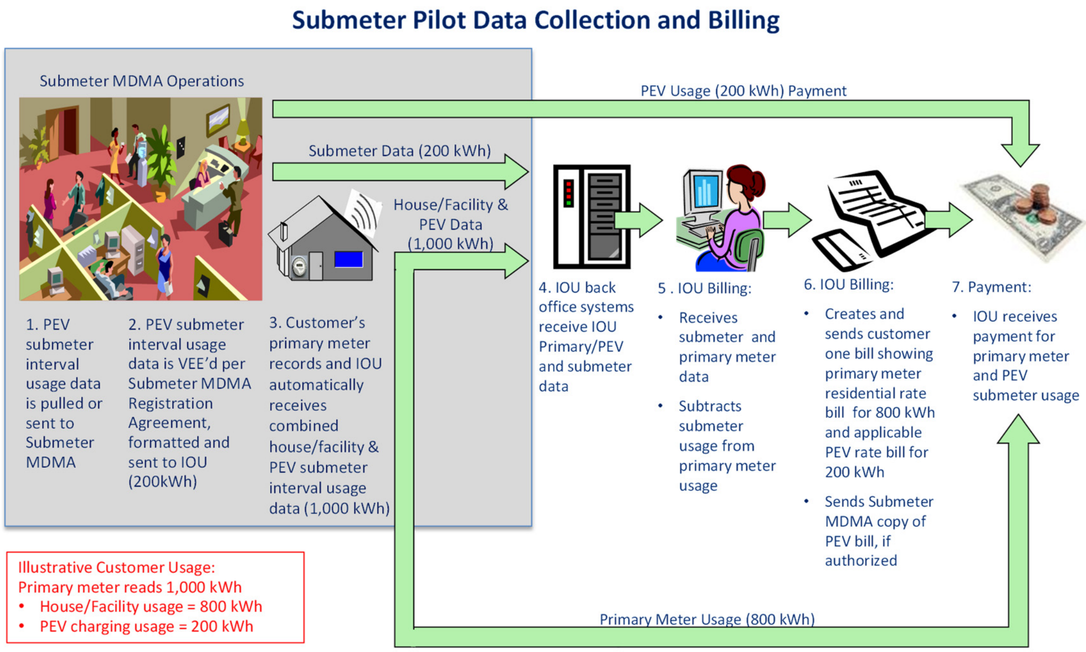

Figure 6. Submeter Pilot Data Collection and Billing Process

Third-Party Evaluator (3PE)

The CPUC directed the IOUs to contract with a 3PE via a competitive bid process to evaluate the performance of the Phase 1 and Phase 2 Pilots and conduct a customer satisfaction survey. Nexant was selected as the 3PE for the Phase 1 Pilot and continued in this role for the Phase 2 Pilot. PG&E contracted Nexant on behalf of the three IOUs, which shared the costs equally (33% each), as mandated by the CPUC.

Customer Satisfaction

Key learnings from Nexant's customer satisfaction surveys conducted during the Phase 2 Pilot across the three IOUs found that:

- 91% of respondents said they were extremely or somewhat satisfied with their overall submetering service during Phase 2, versus 78% in Phase 1.
- 88% of respondents said they would recommend submetering services to a friend or colleague based on their Phase 2 Pilot experience, versus 82% in Phase 1.
- 94% of respondents said they would be interested in participating in another EV submeter program with roughly the same pricing and features, versus 77% of Phase 1 customers who expressed interest in participating in Phase 2.
- Respondents reported charging their EV during off-peak hours 89% of the time, versus 46% of the time before the Phase 2 Pilot.
- 76% of respondents thought they saved money due to the Phase 2 Pilot.

See Nexant's Phase 2 Submetering Pilot Final Report below for additional details.

California Statewide
PEV Submetering Pilo

2.3 Problem Statement

The Submetering Phase 2 Pilot was mandated by the CPUC as follows:

The CPUC issued an Alternative Fuel Vehicle Order Instituting Rulemaking (AFV OIR) Phase 2 Decision 11-07-029 dated July 11, 2011, to overcome barriers to EV deployment. This mandated that the California IOUs develop methods enabling third parties – current utility customers and/or providers of EV services - to submeter EV load to reduce customer costs related to installing a dedicated meter for EV charging.

2.3.1 Regulatory Timeline

- Decision 13-11-002, dated November 14, 2013, adopted the Energy Division Staff PEV Submetering two-phase pilot project.
- Resolution E-4651, dated June 26, 2014, approved the utilities' Schedule Plug-In Electric Vehicle Submetering Pilot tariff with modifications for Phase 1 and 2, including a new start date of May 1, 2016 for the Phase 2 Pilot.
- SCE's Tier 2 Advice Letter, ADVICE 3427-E-A, dated November 4, 2016, established Schedule PEVSP (Plug-In Electric Vehicle Submetering Pilot) Phase 2 and associated forms to support the implementation.
- The IOUs requested and received approval from the CPUC to delay the start of the Submetering Phase 2 Pilot from May 1, 2016 to November 1, 2016.
- The IOUs requested and received approval from the CPUC to delay the start of the Submetering Phase 2 Pilot from November 1, 2016 to January 16, 2017, and to shorten the enrollment period from six months to 3.5 months ending on April 30, 2017.
- The IOUs requested and received approval from the CPUC to delay the submittal of Nexant's 3PE Submetering Phase 2 Pilot final report from December 31, 2017 to September 1, 2018.
- The IOUs requested and received approval from the CPUC to submit the Submetering Protocol 12 months after the date of the Commission's Submetering Protocol Decision, if authorized.
- The IOUs requested and received approval from the CPUC to delay the submittal of Nexant's Submetering Phase 2 Pilot final report from September 1, 2018 to December 4, 2018.
- The CPUC provided Nexant with feedback on the report. Nexant's efforts to respond to the CPUC's request delayed the company's final submittal of the report until April 26, 2019.

2.4 Scope

- **Pilot Term:** The Phase 2 duration lasted 15.5 months, beginning January 16, 2017 and ending April 30, 2018.
- **Pilot Participation:** All residential and commercial customers could participate except streetlight customers and customers taking Direct Access, Electric Service Provider, and Community Aggregation service. Single and multiple customers-of-record were eligible.
- **Pilot Participation Cap:** A maximum of 500 submeters could be enrolled in the Phase 2 Pilot on a first-come, first-served basis. Of the 500 submeters, a limit of 100 submeters could be related to net energy metering (NEM) accounts.

- **Pilot Participation Period:** Customers could participate for up to a maximum of 12 consecutive billing cycles. Customers were able to unenroll from the Pilot at any time but could not re-enroll in Phase 2 unless they were relocating in one of the other IOU's service territories.

2.5 Schedule and Milestones/Deliverables

The following shows the Pilot schedule:

Submetering Phase 2 Pilot Schedule

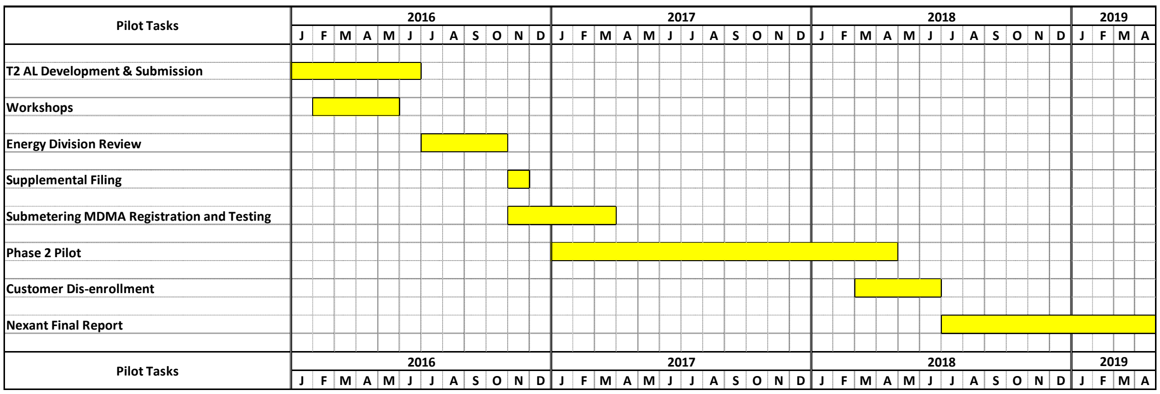

Figure 7. Submetering Phase 2 Pilot Schedule

2.5.1 Deliverables

Customer Enrollment

- SCE enrolled and supported 151 residential submeter customers, including 33 NEM accounts, all of which were limited to a maximum of 12 billing cycles. (*Note: No commercial customers applied.)*

Subtractive Billing Process

- SCE used this manual process to bill EV usage separately from other household usage. All usage, including EV charging, was first measured through the primary meter. The EV usage also was measured separately by a dedicated submeter. The EV usage was then subtracted from the primary meter usage to bill the home's consumption on the customer's current household rate. The EV consumption was billed separately on the TOU-EV-1 rate, as illustrated in Table 1 below.

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

Table 1. SCE Manual Subtractive Billing Illustration

Nexant Third-Party Evaluation Phase 2 Report

- Nexant's Phase 2 Submetering Pilot Final Report includes an assessment of the primary goals of the Phase 2 Pilot:
  - Evaluate customer demand under different submetering scenarios (e.g., single and multiple customer-of-record submetering in single-family homes, apartment units and commercial Facilities)
  - Evaluate billing integration and communication costs under different submetering scenarios.
  - Evaluate the customer experience to determine customer benefits under submetering.
  - Evaluate the potential impacts submetering can have on supporting California's ZEV goals.
- In addition, the report discusses Submeter MDMA business models, submeter accuracy, data and billing issues and Phase 2 conclusions and recommendations. A copy of the report is included on page 10.

Submetering Protocol

- Decision 13-11-002, dated November 14, 2013, scheduled the submittal of the Submetering Protocol by the IOUs to the CPUC on February 1, 2016. Through a series of requests by the IOUs and CPUC approvals, the submittal of the Protocol has been delayed until 12 months after the CPUC Protocol Decision, if authorized.

Nexant Submetering Phase 2 Report

- Nexant delivered the Phase 2 Submetering Report to the CPUC on time on December 4, 2018. At the direction of CPUC's Energy Division (ED), Nexant provided an update and resubmitted the report on April 2, 2019 to address corrections identified by the ED.

3. Project Results

This section compares the planned Phase 2 Pilot project scope versus the results. The Phase 2 Pilot goals and results are addressed in detail in the Phase 2 Submetering Pilot Final Report prepared by Nexant, the third-party evaluator (see page 10).

- **Pilot Term:** The Phase 2 duration lasted 15.5 months, beginning January 16, 2017 and ending April 30, 2018.

- **Pilot Start Date:** The project began on January 16, 2017. (Note: The CPUC approved a delay of the start date from November 1, 2016 to January 16, 2017 to provide more time for the MDMAs to complete Pilot requirements before Phase 2.)

- **Pilot End Date:** The official Pilot end date was April 30, 2018, but was extended by SCE to July 22, 2018 to allow all customers to complete the maximum of 12 billing cycles, if they desired. This action was taken because the three MDMAs were not fully qualified by SCE to begin enrolling customers in the Phase 2 Pilot on January 16, 2017. Each of the MDMAs was late in demonstrating the submeter accuracy requirements and their ability to correctly collect, format and transmit customer submeter data to the IOUs. Due to this delay, the MDMAs delivered 91 of the 151 (60%) Customer Enrollment Agreements (CEAs) to SCE in the final five weeks of the 3.5-month enrollment period, which overloaded SCE's manual enrollment processes. This delay, depicted in Figure 8 below, also may have impacted the MDMAs' ability to recruit and enroll customers up to the total maximum of 500 submeters (see Table 2) – particularly commercial customers, which typically have longer approval cycles and greater infrastructure requirements than residential customers.

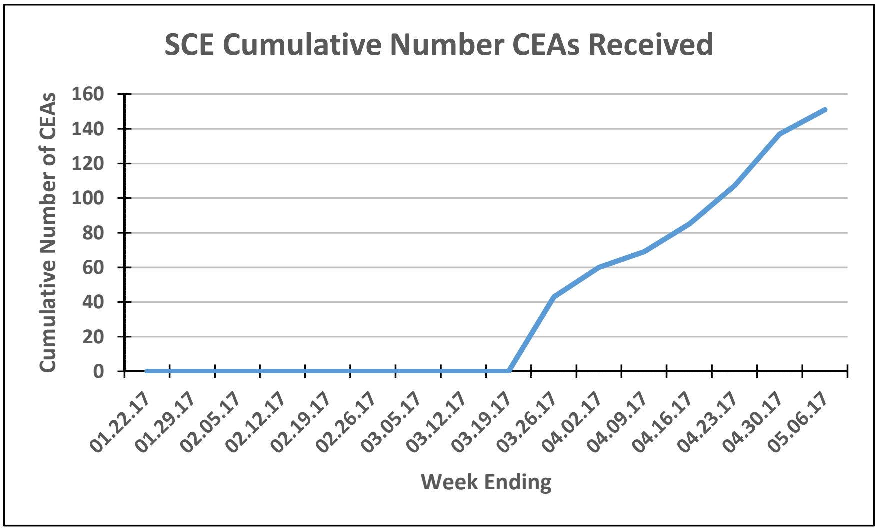

Figure 8. SCE Cumulative Number of CEAs Received

- **Pilot Participation:** All residential and commercial customers were eligible to participate in the Phase 2 Pilot except streetlight customers and customers taking service through Direct Access, Electric Service Provider, and Community Aggregation. Single and multiple customers-of-record were eligible. The final enrollment numbers were:
  - Residential Customers: 149 residential customers enrolled 151 submeters
  - Commercial Customers: No commercial customers applied
  - Single customer-of-record: 149 residential customers enrolled 151 single customer-of-record submeters
  - Multiple customers-of-Record: No multiple customer-of-record customers applied
- **Pilot Participation Cap:** A maximum of 500 submeters could have been enrolled (on a first-come, first-served basis) in the Phase 2 Pilot. Of these 500 submeters, a limit of 100 submeters could have been related to net energy metering (NEM) accounts. The final numbers were:
  - 500 submeter maximum: 151 (30%) were enrolled
  - 100 NEM submeter accounts maximum: 33 (33%) were enrolled

Table 2 below provides a summary of the Phase 2 submeters by MDMA and type.

SCE Enrolled Submeters by MDMA & Type

Submeter MDMA	Residential Submeters			Commercial Submeters	Share of SCE Submeters
	Non-NEM	NEM	Total	Total	(%)
MDMA 1	101	29	130	0	86
MDMA 2	16	4	20	0	13
MDMA 3	1	0	1	0	1
Total	118	33	151	0	100

Table 2. SCE Enrolled Submeters by MDMA and Type

- **Pilot Participation Period:** Customers could participate for up to a maximum of 12 consecutive billing cycles. Customers were able to unenroll from the Pilot at any time, but could not re-enroll in Phase 2 unless they were relocating in one of the other IOU's service territories. Of the 151 enrolled customers, 144 (95%) completed their maximum of 12 billing cycles. See Section 3.3.2, Number of Phase 2 SCE NEM Customer Submeters, for further details.
- **Pilot Billing Issues:** During the Pilot, SCE supported its customers with manual subtractive billing to separately bill household and EV charging on their respective rates. The three IOUs experienced various billing problems caused by MDMA data formatting errors, hardware accuracy issues, server maintenance and NEM customers who charged their EV during generation. These issues caused most of the recorded submeter "Failed" intervals, which occurred when the submeter kilowatt-hours (kWh) exceeded the primary meter kWh. (See Section 3.4 Technical Lessons Learned and Recommendations for further details.)

  Pilot Cost: The Phase 2 project finished under budget. See Section 3.6, Procurement, for further information.

  SCE supported its customers' Pilot participation by answering their questions and resolving their issues. SCE provided a similar service to the three Submeter MDMAs. Section 3.3, Metrics, includes further details on the Phase 2 Pilot results.

3.2 Value Proposition

Primary Principles

- **Greater reliability**: Not applicable
- **Lower Costs:** Many Submetering Phase 2 Pilot participants enrolled to save on their energy costs. For example, 71% of the participants were on residential rate plan Schedule D, and before enrolling in the Pilot they paid $0.35/kWh if on Tier 3 to charge their EV. During the Phase 2 Pilot, these same participants paid $0.13/kWh on SCE's second meter TOU-EV-1 rate when charging their EV during off-peak hours. The average SCE EV owner's vehicle charging monthly load on the separate meter TOU-EV-1 rate was about 345 kWh during the Pilot, resulting in a potential savings of $75.90/month. As noted earlier in this report, 76% of respondents in the Nexant customer satisfaction study thought they saved money due to the Phase 2 Pilot.
- **Increased safety and/or enhanced environmental sustainability:** Use of hybrid plug-in electric vehicles and battery electric vehicles enhanced environmental sustainability by reducing pollutants and carbon emissions.

Secondary Principles

- **The Loading Order**: Not applicable
- **Low-Emission Vehicles/Transportation:** SCE supported the utilization of electric vehicles, in turn enhancing environmental sustainability, via its efforts to enable current customers and/or providers of EV services to submeter EV load – which can reduce customers' energy costs and eliminate the cost to install a dedicated meter for charging.
- **Safe, Reliable and Affordable Energy Services:** See Lower Costs section under Primary Principles.
- **Economic Development:** Not applicable
- **Efficient Use of Ratepayer Monies:** Not applicable

3.3 Metrics

3.3.1 Total Number of SCE Phase 2 Pilot Submeters:

SCE enrolled 151 (30%) of the total 500 maximum submeters, as shown in Figure 9 here:

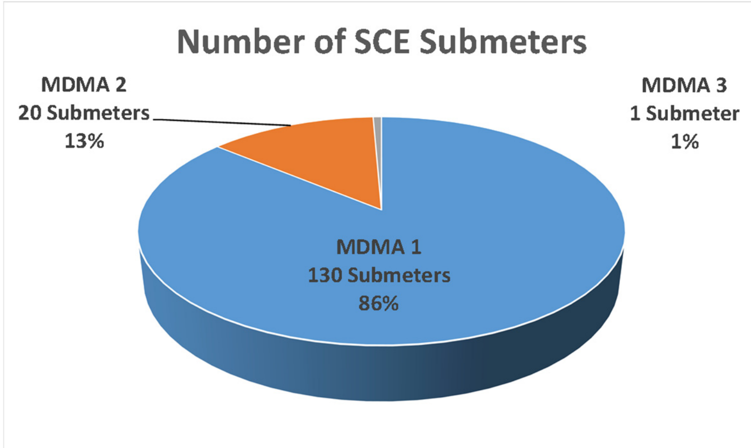

Figure 9. Number of SCE Submeters Enrolled Per MDMA

3.3.2 Number of Phase 2 SCE NEM Customer Submeters

SCE enrolled 33 (33%) of the total 100 maximum NEM submeters (of the 500 submeter limit), as shown in Figure 10 here:

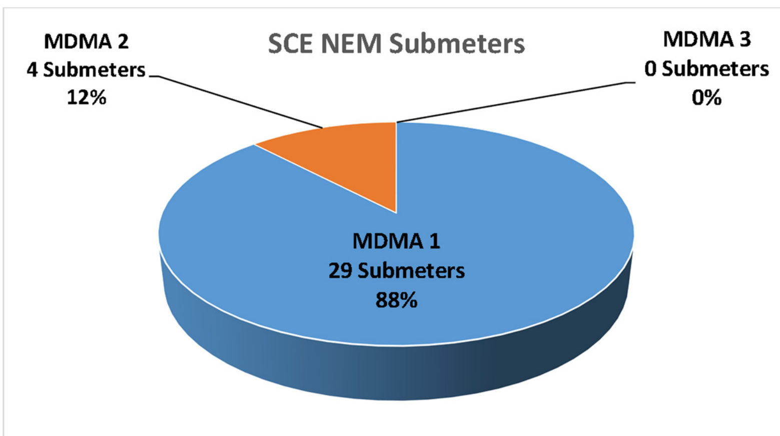

Figure 10. Number of SCE NEM Submeters Enrolled Per MDMA

Customer Early Opt-Outs

- Of the 151 enrolled customer submeters, 144 (95%) completed their maximum of 12 billing cycles, as shown in Figure 11.
- Seven (7) (5%) customers opted to terminate their participation early, as shown in Figure 11.
  - Two (2) customers moved out of SCE's territory.
  - Five (5) customers left the Pilot primarily due to EV charging costs not meeting their expectations.

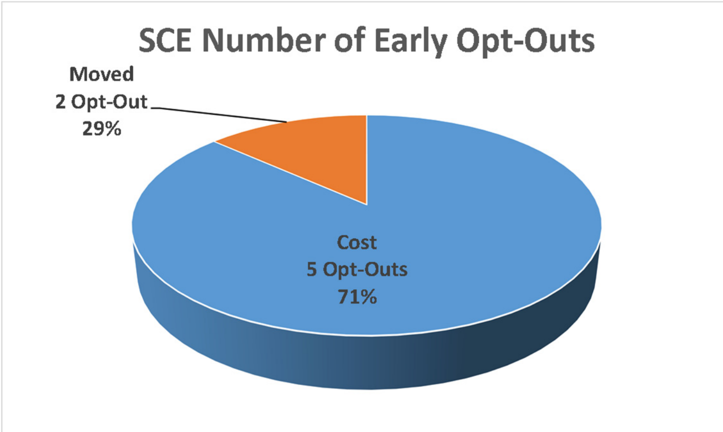

Figure 11. SCE Number of Early Opt-Outs

3.3.3 Complete and Accurate Customer Enrollment Agreements:

SCE returned 59 (39%) of the 151 Customer Enrollment Agreements received from the Submeter MDMAs due to incomplete, inaccurate or incorrect information, as shown in Figures 12 below. Breaking this down by MDMA, SCE returned:

- 54 (42%) of 130 CEAs submitted by MDMA 1, representing 36% of total CEAs
- 5 (25%) of 20 CEAs submitted by MDMA 2, representing 3% of total CEAs
- None (0%) of 1 CEA submitted by MDMA 3, representing 0% of rejected CEAs

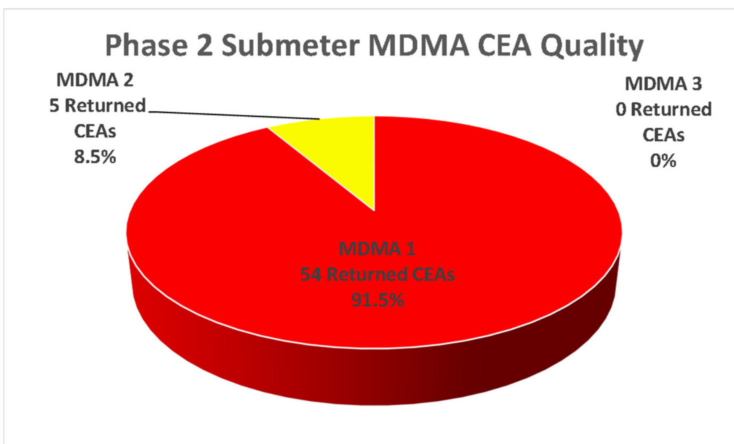

Figure 12. SCE Submeter MDMA Returned CEAs

3.3.4 MDMA Accuracy of Customer Submeter Interval Usage Data

The three Submeter MDMAs all experienced varying submeter accuracy and/or data delivery problems. Some data quality problems were caused by:

1. Acceptance accuracy differences between the IOUs' SmartMeters™ at ±.5% versus the MDMA submeters at ± 1%.
2. Inability of submeters to consistently synch to the U.S. time standard, Universal Time Coordinate (UTC), as defined by the National Institute of Standards and Technology (NIST): The Electric Vehicle Supply Equipment (EVSE) shall be within +/- two (2) minutes of UTC, while the EVSE is in service.
3. Software issues related to how the MDMAs received data from the submeters, formatted and transmitted the data, and maintained the software throughout the Pilot.

4. Server maintenance issues related to the failure to maintain the MDMA server IP address provided to SCE, resulting in the SCE firewall rejecting the MDMA submeter data.

Each of these issues may have contributed to missing or late data or submeter “failed” 15-minute intervals during the subtractive billing process. Failed intervals occurred when the submeter kWh exceeded the primary meter kWh. When this takes place, the submeter data is inaccurate, since it can never exceed the primary meter reading. The submeter data is then disregarded and treated as if there was no EV usage for the time interval(s) involved, as illustrated by the yellow highlighted time interval below in Table 3. Failed intervals ultimately reduced customer charging savings on the lower-cost EV rate and contributed to their dissatisfaction with their Pilot experience.

Failed intervals also can be caused by NEM customers who charge their EV during generation. When this occurs, their EV charging kWh exceeds their net kWh (total household kWh including EV charging minus generation kWh), resulting in failed intervals. This is currently a limitation in SCE’s manual subtractive billing process that must be corrected if the CPUC authorizes the Submetering Protocol.

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

Table 3. MDMA Submeter Data Accuracy Illustration

Failed Intervals Per MDMA

- **MDMA 1’s** customers averaged 15% failed intervals per customer billing cycle over the duration of the Phase 2 Pilot.[2]
    - From the start of the Pilot on January 16, 2017 until October 30, 2017, when MDMA 1 installed a software correction, customers averaged 24.2% failed intervals per customer billing cycle.
    - From November 1, 2017 to the close of the Pilot, customers averaged 6.1% failed intervals per customer billing cycle, a significant improvement.
    - However, starting in December 2017, SCE sent MDMA 1 a series of emails alerting them to serious remaining data problems (up to 98% failed intervals per customer billing cycle) that 17 of their customers were still experiencing. SCE never received any updates from MDMA 1 regarding progress in correcting these deficiencies.
- **MDMA 2’s** customers averaged 3.8% failed intervals per customer billing cycle over the duration of the Pilot.

[2] Excludes customer billing cycles with no recorded EV charging usage (kWh).

- **MDMA 3's** one customer averaged 4.8% failed intervals per customer billing cycle over the duration of the Pilot due to a one-time occurrence.

As shown in Figures 13, 14 and 15, the distribution of failed intervals per customer billing cycle for MDMAs 1, 2 and 3 includes the trend line (•••••••) and uses the same vertical axis scale for comparison purposes.

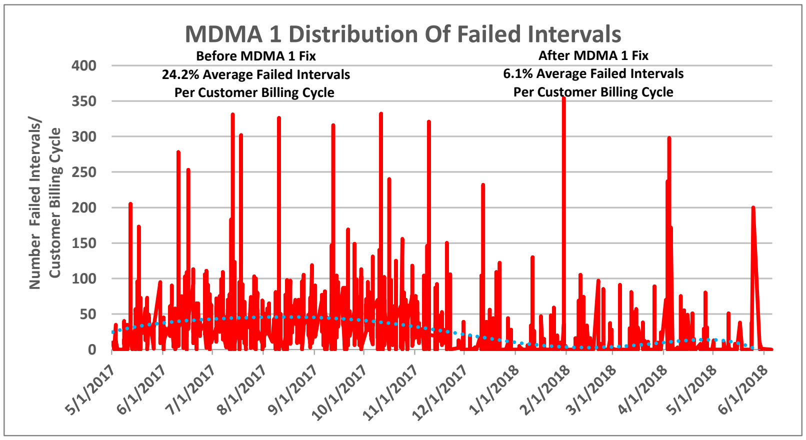

Figure 13. MDMA 1 Distribution of Failed Intervals

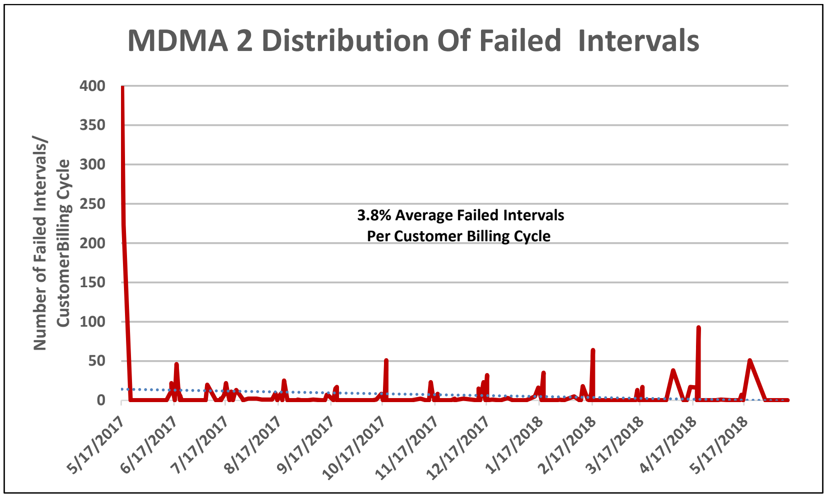

Figure 14. MDMA Distribution of Failed Intervals

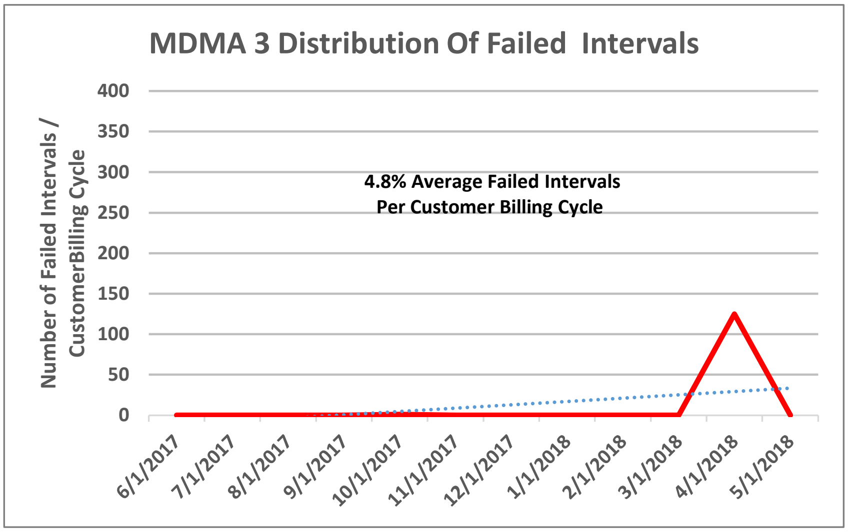

Figure 15. MDMA 3 Distribution of Failed Intervals

3.3.5 Customer Inquiries

SCE received 69 customer inquiries during the Phase 2 Pilot. Figures 16 through 21 show the breakdown of total inquiries by category and sub-category.

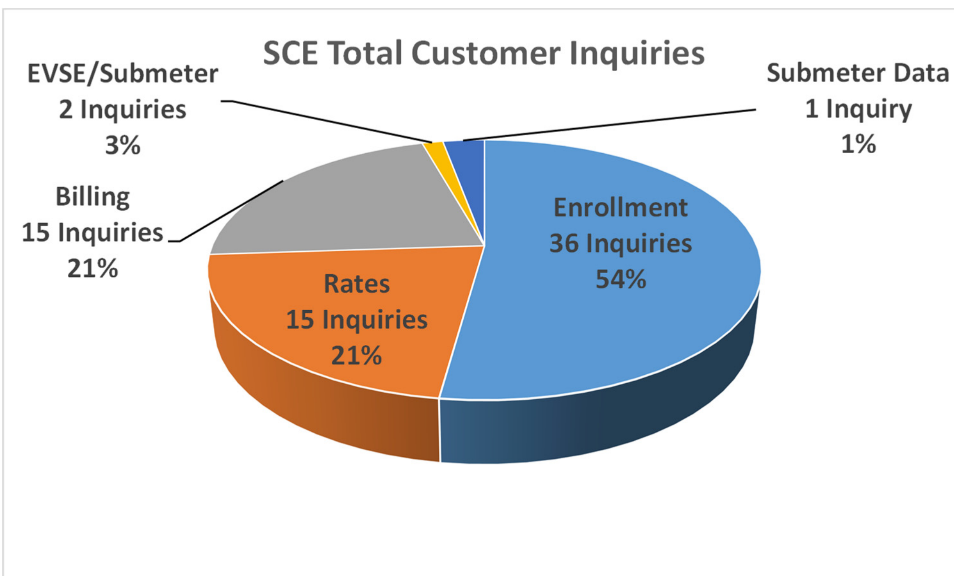

Figure 16. SCE Total Customer Inquiries

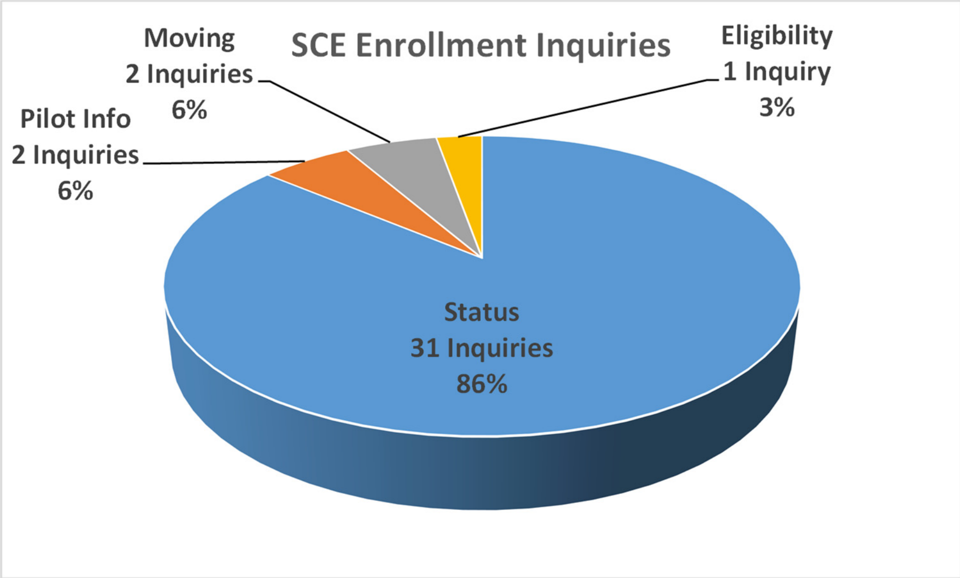

Figure 17. Sub-Categories for Enrollment Inquiries

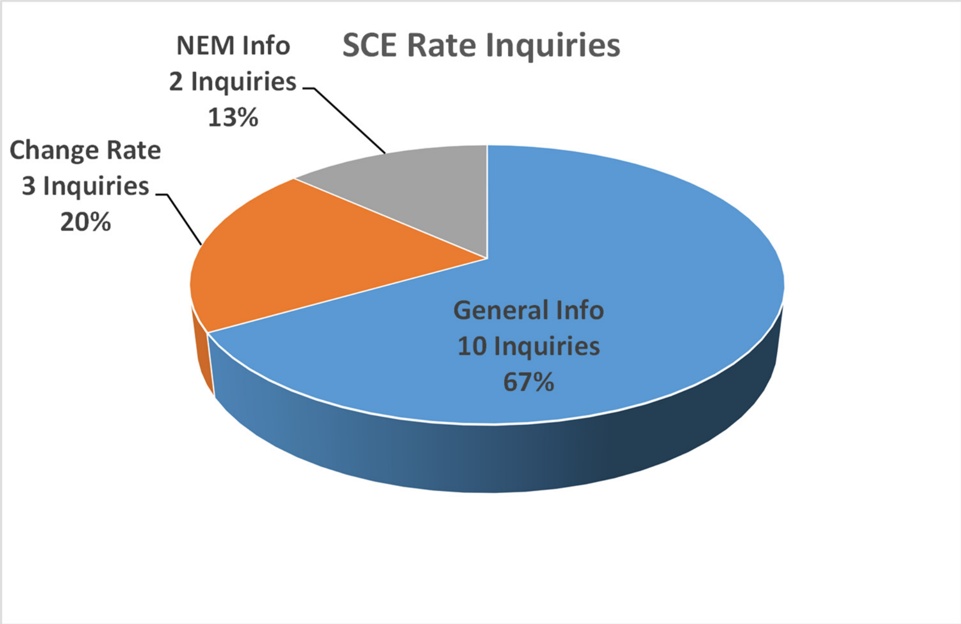

Figure 18. Distribution of Sub-Categories for Rate Inquiries

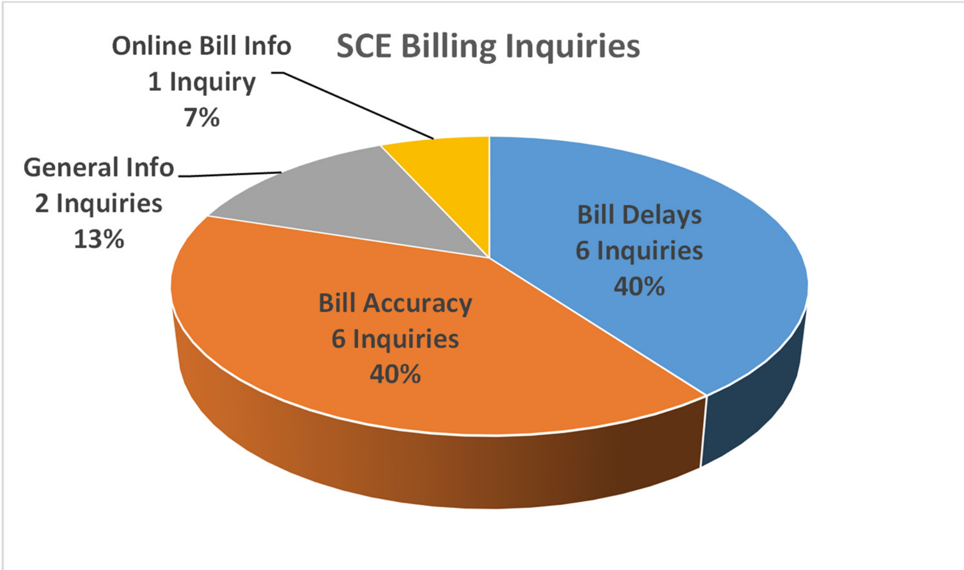

Figure 19. Distribution of Sub-Categories for Billing Inquiries

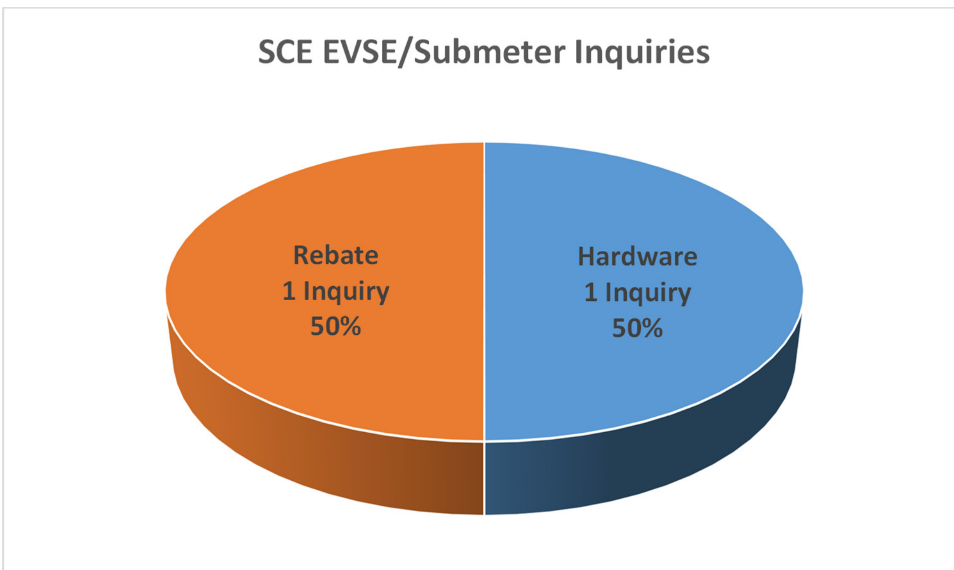

Figure 20. Distribution of Sub-Categories for EVSE Inquiries

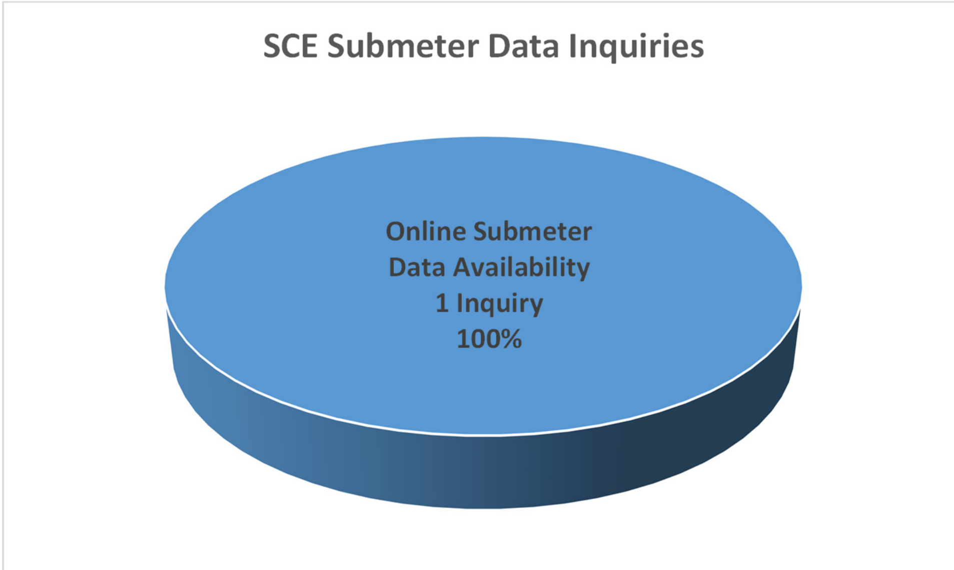

Figure 21. Distribution of Sub-Categories for Submeter Data Inquiries

3.4 Technical Lessons Learned and Recommendations

Lessons learned that will be applied to the Submetering Protocol, if authorized by the CPUC, include:

1. Lesson:

The Submeter MDMAs were not fully prepared to start the Phase 2 Pilot on January 16, 2017.

Actions:

a) Request that the Commission's Energy Division (ED) provide enough time for MDMAs to apply and qualify prior to the start of a possible future operational program, if authorized by the CPUC.
b) Provide the Submetering MDMAs with more comprehensive, detailed training prior to a possible future operational program, if authorized by the CPUC, to help improve their performance and level of customer satisfaction.

2. Lesson:

During the Pilot, SCE supported its customers with manual subtractive billing to separately bill household and EV charging on their respective rates. The three IOUs experienced various billing problems caused by MDMA data formatting errors, hardware accuracy issues, server maintenance and NEM customers who charged their EV during generation. These issues caused most of the recorded submeter "Failed" intervals, which occurred when the submeter kWh exceeded the primary meter kWh. (See Section 3.3.4 Submeter MDMA Accuracy of Customer Submeter Interval Usage Data for further details.)

Actions:

The MDMAs will be required to meet the same accuracy requirements as the IOUs' SmartMeters™ if the Submetering Protocol is authorized by the CPUC. Testing of MDMA submeters will be performed using the same requirements utilized by the IOUs when testing their SmartMeters.

a) Require the submeter to be tested to demonstrate meter acceptance accuracy of +/- .05%, and maintain accuracy of +/- 2% while the submeter is in service prior to the start of a possible future submetering operational program. (The term ‘accuracy’ is equivalent to the same term used in the American National Standards Institute (ANSI) C-12 standard, or equivalent to ‘tolerance’ in the National Institute of Standards and Technology (NIST) Handbook 44, Section 3.40 T.2.)
b) Require the submeter to be tested to demonstrate that its time is synchronized to the Universal Time Coordinate (UTC) standard prior to the start of a possible future submetering operational program. (UTC is defined by NIST.) The submeter must be within +/- two (2) minutes of UTC, while the Electric Vehicle Supply Equipment (EVSE) is in service.
c) Require the MDMAs to provide the IOUs with the means to test the submeter while it is in service. Also work with the MDMAs to develop submeter field testing, including possibly adding a submeter optical probe or a display.

3. **Lesson:**

MDMA performance and SCE billing were negatively impacted by “back-office” issues including:

a) Software issues related to how the MDMAs received data from their submeters, formatted the data and maintained the software throughout the Pilot contributed to MDMA data accuracy problems.
b) Hardware issues related to maintaining the server IP address resulted in the SCE firewall rejecting MDMA submeter data and causing customers’ EV charging usage to be billed on their household rate.

These issues impacted the quality and timeliness of the MDMAs’ submeter data transfer to SCE.

Actions:

Provide the MDMAs with comprehensive, detailed training focused on back-office management issues prior to a possible future operational program, if authorized by the CPUC, to help improve their performance and level of customer satisfaction.

4. **Lesson:**

The manual customer Pilot processes were challenging for SCE customers, Submeter MDMAs and SCE support organizations.

Actions:

Automate the following manual Pilot processes for a future operational Submetering Program, if authorized by the CPUC:

a) Enroll customers in the EV submetering service.
b) Set up submeter service accounts, including the creation and turn on of virtual submeters for single and multiple customers-of-record
c) Receive and process 15-minute interval submeter data from the MDMAs.
d) Perform subtractive billing: Subtract the EV charging usage recorded on the submeter from the customer’s primary meter household usage which includes the charging use. Then provide a single bill that includes the separate charges for 1) the primary meter usage less the EV charging use on the customer’s existing primary meter rate, and 2) the EV charging usage on the appropriate separate meter EV rate (currently TOU-EV-1).
e) Close out submeter service accounts and turn off virtual submeters.
f) Review MDMA invoices for accuracy and completeness before the Portfolio Management Office (PMO) approves them for payment.

5. Lesson:

NEM customers can inadvertently experience failed intervals (e.g., submeter usage exceeds household usage) when charging their EV during generation. This is due to SCE's system and manual subtractive billing limitations that require using net usage kWh (e.g., total household kWh including EV charging minus generation kWh) instead of total household usage. This limitation can sometimes result in customers' EV charging kWh exceeding their net kWh, resulting in a failed interval.

Action:

In addition to automating the process listed in Lesson 4 above, this limitation in SCE's system and manual subtractive billing process must be corrected if the CPUC authorizes the Submetering Protocol.

3.5 Technology/Knowledge Transfer Plan

There are three potential means to transfer technology/knowledge:

1. Nexant, the independent third-party evaluator, provided a Final Phase 2 Report. This report includes technology/knowledge transfer for the results of both Submetering Enablement Demonstration pilot phases to apply to future submetering applications if the Submetering Protocol is authorized by the CPUC.
2. This document (the EPIC Phase 2 Pilot Final Project Report) includes technical results, findings, recommendations and lessons learned, and can be distributed/presented to share and transfer this information.
3. The Submetering Protocol, if authorized by the CPUC, would incorporate technology/knowledge transfer for the results of both pilot phases to apply to future submetering applications. The Protocol also would also include the updated cost and schedule to automate key Pilot processes such as enrollment, submeter account setup/closeout, subtractive billing and MDMA invoice review.

3.6 Procurement

The following Phase 2 Pilot procurement plan is from the Project Management Plan (PMP).

Procurement Type (Services, Material, Software)	Vendor	Need Date	Approximate Cost
Contract Labor/ Services	Nexant: Third-Party Evaluator	Second Quarter 2016	**$333,000:** SCE's portion of shared expense among the three IOUs for Phase 2
Contract Labor/ Services	Corepoint1	Third Quarter 2015	**$818,809**

Table 4. Phase 2 Procurement Plan

Contract Labor/Services:

- **Nexant:** Procured as originally envisioned. Actual costs were $193,530, 58% of the baseline estimate of $333,000 primarily because only 151 submeters were enrolled out of a maximum of 500. The actual cost also included an added task to perform acceptance tests of each MDMA's charging station with embedded submeter to determine if it met the IOUs' Phase 2 Pilot acceptance test accuracy requirements of ± 1%.
- **Corepoint1:** Procured as originally envisioned. Actual costs for PMO services by Corepopint1 were $818,809 through December 31, 2019.

3.7 Stakeholder Engagement

Each of the SCE organizations listed in Table 5 below played a significant role in the success of the Phase 2 Submetering Pilot. Meetings and informal discussions occurred throughout the Pilot.

SCE Stakeholder Organization	Immediate Point of Contact	Supervising Manager	Project Role
NPD&L/SP	Al Shepetuk	Mauro Dresti	Project management
CCC - Program Services	Danielle Casillas	Kent Turner	Customer enrollment
RSO - Customer Billing Operations	Sheryl Avelar	Carla Renteria	Submeter set-up and close-out
RSO - Customer Billing Operations	Sylvia Gonzalez	Lisa Callaghan	Subtractive billing
eMobility	Al Shepetuk	Mauro Dresti	Manage project
CS - CCC/OLS	Lorenza Medina	Anitra Polk	Respond to EV customer inquiries
Legal	Andrea Tozer	Janet Combs	Oversee Legal ompliance
Reg Ops - Tariff & Compliant Cases	Shiela Linao	Douglas Snow	Oversee Regulatory compliance
IT	Naveen Bhat Pushpa Chaluvadhi	Linda Tierney Rick Nanda	Set-up MDMAs and receive submeter data
Emerging Technology Acquisition & Implementation	Alexandria Vallejo	Kent Thomson	Oversee EPIC Project funding
Regulatory Affairs and Compliance	Aaron Renfro	Nathan Todaro	Oversee EPIC program funding
T&D - Grid Technology & Moderenizatioon	Joshua McDonald	Percy Haralson	Determine use of open meter standards
T&D - Energy Delivery & Distribution	Alexander Rivney	Maninder Sahoto	Determine metering requirements

Table 5. Phase 2 Pilot SCE Stakeholder Organizations

The primary external stakeholders – the CPUC Energy Division (ED) and the MDMAs – played a key role in the success of the Phase 2 Submetering Pilot.

Stakeholder Expectations:

- CPUC/ED expectations were detailed in Decision 13-11-002.

- MDMA expectations were addressed in the Advice Letter 3402-E.

Stakeholder Awareness of Project Performance:

- Monthly meetings were held with the three IOUs and the CPUC/ED throughout the Pilot to discuss progress, issues and solutions.
- Meeting and monthly performance reports were provided to the MDMAs, as needed.

Stakeholder Notification of Pilot Results:

- All external stakeholders reviewed the Phase 2 Final Report prior to its formal submittal to the CPUC/ED on December 4, 2018.

List of Acronyms

3PE	Third-Party Evaluator
AFV	Alternative Fuel Vehicle
ANSI	American National Standards Institute
CEA	Customer Enrollment Agreement
CPUC	California Public Utilities Commission
ED	Energy Division (CPUC)
EPIC	Electric Program Investment Charge
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
IOU	Investor-Owned Utility
kWh	Kilowatt-Hour
MDMA	Meter Data Management Agents
NEM	Net Energy Metering
NIST	National Institute of Standards and Technology
OIR	Order Instituting Rulemaking
PEV	Plug-In Electric Vehicle
PEVSP	Plug-In Electric Vehicle Submetering Pilot
PG&E	Pacific Gas and Electric
PMO	Portfolio Management Office
PMP	Project Management Plan
PO	Purchase Order
RA	(Submeter MDMA) Registration Agreement
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
TOU	Time-of-Use
UTC	Universal Time Coordinate
ZEV	Zero-Emission Vehicle