Regulatory Affairs
8330 Century Park Ct. CP32F
San Diego, CA 92123-1530

February 28, 2022

Pete Skala and Simon Baker
Interim Energy Division Directors
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102-3298

RE: COMPLIANCE FILING OF SAN DIEGO GAS & ELECTRIC COMPANY'S (U 902 E) 2020 ELECTRIC PROGRAM INVESTMENT CHARGE ANNUAL REPORT

Dear Mr. Skala and Mr. Baker:

In compliance with Ordering Paragraph 16 of Decision (D.) 12-05-037 and in accordance with the Annual Report Outline provided in Attachment 5 of D.13-11-025, San Diego Gas & Electric Company (SDG&E) hereby submits its 2021 Annual Report for its Electric Program Investment Charge (EPIC) Program (Report), provided as Attachment A hereto. In addition, SDG&E provides the excel file titled "SDG&E 2021 EPIC Project Status Report" in accordance with D.13-11-025 as Attachment B.[1] All EPIC-1 and EPIC-2 comprehensive final project reports were delivered with prior annual reports and are posted on SDG&E's websites at www.sdge.com/epic. Seven comprehensive final project reports for the EPIC-3

[1] SDG&E, the California Energy Commission (CEC), Pacific Gas and Electric Company (PG&E), and Southern California Edison Company (SCE) (together, the EPIC Administrators) are required to provide with the annual report "electronically in spreadsheet format the information identified in Attachment 6 to report on projects described in Section 4.b of the EPIC annual report outline adopted by this decision." D.13-11-025 at 63. *Id*. at Attachment 5 and Attachment 6.

Cycle were completed in 2021 and are attached to this annual report.[2] Together, these documents provide an overview of SDG&E's EPIC activities and program financial information during the 2021 calendar year.

SDG&E and its fellow EPIC Administrators are required to each submit an annual report "detailing program activities."[3] The annual reports are designed "to facilitate consistent reporting by the [EPIC] Administrators on their investment plans and project results."[4] In accordance with D.12-05-037, SDG&E serves this Report on "all parties in the most recent EPIC proceeding, and all parties to the most recent general rate cases for [SDG&E, PG&E, and SCE], and each successful and unsuccessful applicant for an EPIC funding award" during the 2021 calendar year.[5]

Sincerely,

/s/ SDG&E Regulatory Affairs

cc: SDG&E Central Files

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[2] The EPIC Administrators "must include with their [EPIC] annual report a final report on every project completed during the previous year." D.13-11-025 at 136, Ordering Paragraph 14.
[3] D.12-05-037 at 8.
[4] D.13-11-025 at 4-5, 62.
[5] *Id*. at Ordering Paragraph 16.

ATTACHMENT A

SDG&E® 2021 EPIC Annual Report

San Diego Gas & Electric Company

2021 EPIC Annual Report

February 28, 2022

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Attachment B – 2020 Annual Report Spreadsheet follows this Attachment A (Excel document).

I. EXECUTIVE SUMMARY

Pursuant to Ordering Paragraph 16 of Decision D.12-05-037 and in accordance with the Annual Report outline provided in Attachment 5 of D.13-11-025, San Diego Gas & Electric Company (SDG&E) hereby submits its 2021 EPIC Annual Report (Report). This Report provides an overview of SDG&E's EPIC activities during the 2021 calendar year. As required by D.13-11-025, SDG&E is providing additional information about SDG&E's EPIC activities in an excel file titled, "SDG&E 2021 EPIC Project Status Report" as Attachment B. There are seven comprehensive final project reports attached to this annual report.[1]

SDG&E proposed and received approval for five projects that demonstrate system integration solutions in its first triennial application for years 2012-2014 (EPIC-1).[2] In addition, SDG&E proposed and received approval for six projects that demonstrate grid modernization and technology integration solutions in its second triennial application for years 2015-2017 (EPIC-2).[3] SDG&E proposed and received approval for seven projects in multiple policy areas in its third triennial application for years 2018-2020 (EPIC-3).[4] This report provides an update on SDG&E's 2021 progress and year-end status for projects approved for EPIC-1, EPIC-2, and EPIC-3.

A. Overview of Programs/Plan Highlights

In A.12-11-002, SDG&E requested Commission approval of five programs that demonstrate advanced distribution system integration solutions. In November 2013, SDG&E's Application and First Triennial EPIC Plan was approved in full, with minor modifications, by the Commission in D.13-11-025.
In A.14-05-004, SDG&E requested Commission approval of its Second Triennial EPIC Plan which included five programs that have the potential to help modernize the utility power system to improve customer benefits, as well as a sixth project for SDG&E participation in industry RD&D consortia. In April 2015, SDG&E's Application and Second Triennial EPIC Plan was approved in full, with minor modifications, by the Commission in D.15-04-020.

In A.17-05-009[5], SDG&E requested Commission approval of its Third Triennial EPIC Application which included seven project areas addressing topics in grid modernization, such as safety, advanced operation solutions, and resiliency. The total estimated cost in the application for the third EPIC cycle was $9,768k. D.18-10-052 approved the project areas that were included in the application but only released 2/3 of the funds, pending approval of a Research Administration Plan (RAP), which occurred in 2020. The RAP application A.19-04-026 was a

[1] D.13-11-025 at 63 and 136.
[2] SDG&E's Application (A.12-11-002) for EPIC-1, approved in D.13-11-025, issued November 19, 2013.
[3] SDG&E's Application (A.14-05-004) for EPIC-2, approved in D.15-04-020, issued April 15, 2015
[4] SDG&E's Application (A.17-05-009) for EPIC-3, approved in D.18-10-052, issued November 2, 2018.
[5] SDG&E's Application (A.17-05-009), approved in D.18-10-052, issued November 2, 2018.
[6] The IOUs' Joint Application (A1904026), approved in D.20-02-003, issued February 10, 2020.

joint filing of the IOU administrators and was approved in D.20-02-003, releasing the remaining funds.[6] The EPIC-3 funds were applied to four project areas in A.19-04-026.

B. Status of EPIC-1 and EPIC-2 Projects

All EPIC-1 and EPIC-2 projects were completed by the close of 2018, as reported in the 2019 Annual Report. All final reports for the EPIC-1 and EPIC-2 cycles were provided with prior annual reports and are posted on the SDG&E EPIC public web site.

Current funding information for SDG&E's EPIC-3 cycle is provided in Table 1.

Table 1. SDG&E's EPIC-3 (2018-2020) Portfolio as of December 31, 2021

EPIC-3 Projects (2018--2021)				
EPIC-3 Projects	**Incurred[7] Costs ($ thousands)**	**Encumbered[8] Costs ($ thousands)**	**Commitments[9] ($ thousands)**	**Project Status**
3. Application of Advanced Metering Infrastructure (AMI) Data to Advanced Utility System Operations	1,521	1,800	1,800	In Progress
4. Safety Training Simulators with Augmented Visualization	1,988	2,100	2,100	In Progress
5. Unmanned Aircraft Systems (UAS) with Advanced Image Processing for Electric Utility Inspection and Operations	693	729	729	In Progress
7. Demonstration of Multiple-Purpose Mobile Battery for Port of San Diego and Other Applications	2,309	4,223	4,223	In Progress
SDG&E Program Administration	610	916	916	In Progress
Total	**$7,121**	**$9,768**	**$9,768**	

[7] As used in this Report, incurred costs mean actual booked expenditures.
[8] As used in this Report, encumbered costs are funds that are specified for contracts (D.13-11-025 at 101; Ordering Paragraph 45) or for in-house work necessary in collaboration with a contractor (D.13-11-025 at 53). They differ from commitments in that commitments are the identification of blocks of funds to be assigned to projects, whereas encumbrances specify how the commitments will be used in the projects.
[9] As used in this Report, commitment means assigned for anticipated work on a project, including anticipated contractual commitments, equipment purchases, software licenses, associated technical work by the SDG&E project team, and other expenses directly associated with the project work.

C. Status Summary of EPIC Projects

1. EPIC-1 and EPIC-2 Projects

All EPIC-1 and EPIC-2 projects were completed by the end of 2018. Summaries of those projects can be found in SDG&E's prior annual reports on SDG&E's EPIC website. The comprehensive final reports for those projects can also be found on that website. The site address is www.sdge.com/epic.

2. EPIC-3 Projects

The following are brief summaries of the projects that have been launched from SDG&E's CPUC-approved EPIC-3 application. More detailed descriptions of activities in these projects appear in the main body of this annual report.

Project 3: Application of Advanced Metering Infrastructure (AMI) Data to Advanced Utility System Operations

This project included performing pre-commercial demonstrations of two critical capabilities (towards modernization) for leveraging SDG&E's AMI system with its 1.4 million endpoints to provide actionable secondary voltage data and analysis to SDG&E and other prospective users. The following two key modules were the focus of this project:

- **Module 1: AMI System as a Voltage Sensor Network**

  This module was performed as part of a Cooperative Research and Development Agreement (CRADA) with the National Renewable Energy Laboratory (NREL). The primary focus of the module was to demonstrate and evaluate the capabilities of AMI-based controls for distribution system operations, including monitoring and control at the secondary transformer level using existing AMI infrastructure. In other words, in commercial use the grid-edge monitoring systems and controls provided by the third- party vendors (procured by SDG&E) would perform grid operations using AMI data. The module scope also included efforts for developing and validating models that are representative of real SDG&E feeders in a distribution simulation environment. These models were tuned and validated using AMI data collected from the field to produce accurate feeder models. Moreover, a demonstration comprising of control use case scenarios, performance metrics and evaluation procedures was performed.

  The execution of the pre-commercial demonstration, data gathering, and analysis of results was completed and incorporated into a comprehensive final project report written and finalized in the third and fourth quarters of 2021. The final project report is provided in this document's appendix and is posted to SDG&E's public website at www.sdge.com/epic.

- **Module 2: Phase Identification**

  Visibility into the physical state of distribution system and its real-time load flow conditions is required to advance grid modernization. Accurate phasing information is essential for optimal control and effective operation of a utility distribution system with modernization functions such as advanced distribution management system (ADMS) and distributed energy resource management system (DERMS) platforms. Thus, it is becoming more important to have accurate information (i.e., phase identification) of the distribution network to be able to effectively manage/control it. This module demonstrated the application of AMI data to automatically identify phasing information within the SDG&E distribution system.

  Two vendors were selected through competitive procurement with contract effective dates in October 2019 and August 2021. An SDG&E internal methodology and the two vendor methodologies were developed, and demonstrations were conducted throughout 2021. Interim internal reports were completed by each vendor and the internal SDG&E team. The interim reports were integrated into a comprehensive final project report that includes each of the methodologies demonstrated and a summary of the results. The final project report is provided in this document's appendix and is posted to SDG&E's public website at www.sdge.com/epic.

Project 4: Safety Training Simulators with Augmented Visualization

This project was divided into two modules: "Training Environment for System Operators Allowing Focused Patrol of Overhead Distribution" and "Personal Protective Grounding/Equal Potential Zones (PPG/EPZ) Training on the Electric Underground Distribution System".

- **Module 1: Focused Patrol Stimulator**

  The main feature of the project was to demonstrate a functioning pre-commercial training simulator that can help narrow the search location of a fault during a power outage for a set of selected test circuits. This new training environment will be utilized to teach the system operators as well as the technical support team staff to recognize, understand and utilize, the signals that a newly installed array of Wireless Fault Indicators (WFIs)--in conjunction with existing SCADA capable devices, upgraded AMI functionality, and a reconfigured ADMS built-in algorithm-to accurately predict the region of the fault, thereby greatly reducing the customer impact of a distribution overhead line power outage. This benefit will come from the reduced duration and extent of distribution overhead line patrols. The selected test circuits are mainly in rural communities, which are commonly subjected to Public Safety Power Shutoffs (PSPS) during high wind events, following many months of very dry conditions. After the project was sufficiently scoped and described, a vendor was selected through a competitive procurement (RFP) to work with the internal SDG&E project team, and contract executions occurred in late 2020 and early 2021. The bulk of the vendor-related work was accomplished in Q2 through Q4 of the year, with the final report prepared by the end of the year.

- **Module 2: Personal Protective Grounding/Equal Potential Zone (PPG/EPZ) Simulated Training Demonstration**

  This project was a pre-commercial demonstration of a Virtual Reality (VR) training simulator for PPG/EPZ on the electric distribution underground (UG) system. This new training format was applied to students during initial and/or refresher compliance training to improve understanding of the procedures for PPG/EPZ.

  SDG&E used internal staff as the subject matter experts and contracted with a software vendor to provide a training solution to demonstrate improved PPG/EPZ practices. The selected use cases formed the basis for the VR demonstration. SDG&E built an energized test yard at which it evaluated the effectiveness of the VR training compared to existing practice, in terms of student learning outcomes.

  A vendor was selected by a competitive Request for Proposal (RFP) process, and a contract was awarded to one of the bidders to work with the SDG&E team in performing the demonstration. The test yard was completed in the 2020 calendar year. The demonstrations were conducted and concluded in the latter half of 2021. A technical writer was selected to draft the comprehensive final report for this module; that report was drafted, edited, and finalized by the end of the year.

  The final project reports for both modules are provided in this document's appendix and are posted to SDG&E's public website at www.sdge.com/epic.

<u>Project 5: Unmanned Aircraft Systems (UAS) with Advanced Image Processing for Electric Utility Inspection and Operations</u>

The project demonstrated new applications of Unmanned Aircraft Systems (UAS) with enhanced image processing capabilities for electric operations. The project defined, demonstrated, and evaluated concepts for instrumentation and monitoring of the power system equipment using enhanced imaging and sensor technology on UAS. The project evaluated the potential to increase reliability, safety and cost efficiency to improve power system operations. The use cases included:

- Telepresence

- Beyond Line of Sight (BLOS)
- Night Flights
- Corona Camera
- Tethering
- Line Pulling

A comprehensive final report was developed, including the pre-commercial demonstrations descriptions, findings, recommendations, metrics, value proposition and conclusions. The final project report is provided in this document's appendix and is posted to SDG&E's public website at www.sdge.com/epic.

Project 7: Demonstration of Multi-Purpose Mobile Battery for Port of San Diego and/or Other Applications

The objective of this project is to undertake a pre-commercial demonstration of multi-purpose mobile battery energy storage systems (MBESS). The project was originally intended to examine the possibilities for using a mobile battery at its home base, tentatively the San Diego Unified Port District ("the District"), and at secondary energy hubs.

In fulfillment of "other applications" proposed, an additional mobile battery system use case has been identified for potential implementation at community resource centers (CRCs). This application will assess the value proposition for providing emergency backup power at CRCs during evacuations, power outages and, more specifically, during wildfire situations (i.e. public safety power shutoffs). Based on the applications identified and to better approach the demonstration, this project was divided into two modules.

- **Module 1 – San Diego Unified Port District (referred to as "the District") and other secondary energy hubs:**

  A primary issue for commercial and industrial businesses within the District is low load usage yet high peak demand for relatively short periods, which results in undesirable energy demand charges. This project demonstrated a new solution to assist the District and other surrounding energy hubs in alleviating these problems. Pursuing a more traditional solution for load factor improvements has proven to be challenging due to geographical restrictions for the District.

  While the original intent was for a MBESS deployment at the cruise ship terminal at the Port of San Diego, a variety of factors made deployment at this site infeasible during the pre-commercial demonstration window. So, another site, with similar load trends was chosen as one of two deployment sites. Ultimately, MBESS deployment was moved between the Marine Group Boat Works and Cameron Corners Microgrid sites to demonstrate the stacked benefits of multiple use cases across various sites.

A single vendor was selected through competitive procurement to provide a 362kW/1499kWh battery, as well as provide support during commissioning tests and deployments. A second vendor was selected to provide engineering support throughout the demonstration, perform data analysis, and prepare the comprehensive final report for Module 1.

- **Module 2 – Community Resource Centers (CRC):**

  As an additional application, a smaller mobile battery energy storage system (BESS) was competitively procured for demonstration as a backup power solution during emergency response situations such as wildfires and other calamities. In anticipation of extended power outages, such as public safety power shutoffs (PSPS), SDG&E may request activation of a CRC in affected areas. These facilities offer resources for residents such as water and food supply, electronic device charging, and outage information updates. Enhancing the resiliency of these communities will contribute to the accessibility of resources for affected customers. A vendor was selected through competitive procurement to provide a 100kW/525kWh battery, engineering support throughout the demonstration, data analysis, and preparation of the comprehensive final report for Module 2.

Overall, the project evaluated the effectiveness and value proposition of implementing a mobile battery (or multiple mobile batteries) to showcase the benefits when rotated between applications and identify the desirable applications and strategies for commercial adoption.

Main Body

of

2021 SDG&E EPIC Annual Report

I. INTRODUCTION AND OVERVIEW

A. Background on the EPIC Program

The EPIC program was established by the California Public Utilities Commission (alternatively referred to as "The Commission" or "CPUC") in D.11-12-035 to provide public interest investments in applied research and development, technology demonstration and deployment, market support, and market facilitation of clean energy technologies and approaches for the benefit of ratepayers of California investor-owned utilities (IOUs). D.12-05-037 established the purposes and governance structure for the EPIC program and D.13-11-025 clarified many of the program's regulatory requirements.

The EPIC program is designed to provide funding for electric utility research, development, and demonstration (RD&D). Specific funding allotments are made to four EPIC program administrators, including SDG&E.[1] The EPIC program was intended to run through 2020 and is comprised of three triennial program cycles (*i.e.*, EPIC-1, EPIC-2, EPIC-3). It has been extended into 2021 due to delays in Commission decisions on the EPIC-3 program applications.

B. EPIC Program Components

The IOUs, including SDG&E, may only administer EPIC projects in the area of pre-commercial technology demonstration and deployment (TD&D). Post-commercial demonstrations and deployments are not permitted under the program. Utility participation in the early stages of the research and development process, *i.e.*, basic research and applied research for new utility-related technology, is also not permitted.

C. EPIC Program Regulatory Process

Pursuant to D.12-05-037, SDG&E was required to submit an application seeking Commission approval of an EPIC plan every three years. SDG&E submitted its First Triennial EPIC Plan for years 2012-2014 (A.12-11-002) on November 1, 2012 (EPIC-1) and received full Commission approval of its EPIC-1 Plan in D.13-11-025. No hearings were held. SDG&E submitted its Second Triennial EPIC Plan for years 2015-2017 (A.14-05-004) on May 1, 2014 (EPIC-2) and received Commission approval of its EPIC-2 Plan in D.15-04-020. No hearings were held. SDG&E submitted its Third Triennial EPIC Plan for years 2018-2020 (A.17-05-009) on May 1, 2017 (EPIC-3). The Commission approved SDG&E's EPIC-3 Application in D.18-10-052, issued on November 2, 2018, with partial release of the funds, pending approval of a Research Administration Plan (RAP) which occurred in 2020. The RAP application A.19-04-026 was a joint filing of the IOU administrators and was approved in D.20-02-003. The EPIC-3 funds were applied to four of project areas in the approved application.

[1] The EPIC administrators are the California Energy Commission (CEC), SDG&E, Southern California Edison Company (SCE) and Pacific Gas and Electric Company (PG&E).

In accordance with Ordering Paragraph 16 of D.12-05-037 and consistent with the Annual Report outline provided in Attachment 5 of D.13-11-025, SDG&E and the other EPIC Administrators are required to submit an annual report annually on February 28, 2013, through February 28, 2020. Because the EPIC-3 cycle was approved late, these annual reports have been continued through 2021. This is the tenth annual report submitted by SDG&E for its EPIC program.

D. Coordination among EPIC Administrators

The four EPIC Administrators have regular, recurring teleconferences on a bi-weekly basis, and the utility administrators teleconference weekly to coordinate EPIC activities.

E. Transparent and Public Process

SDG&E is committed to conducting competitive procurements for those parts of the project work that require contracted services or major purchases of equipment or software. A summary of executed contracts for each EPIC-3 project is provided in Table 2 below.

Table 2. EPIC-3 Contracts Summary by Project

Cycle	Project Name	Contractor	Contract Effective Date
EPIC-3	Application of Advanced Metering Infrastructure (AMI) Data to Advanced Utility System Operations	Itron, Inc.	Contract for Task Work 10/31/19
EPIC-3	Application of Advanced Metering Infrastructure (AMI) Data to Advanced Utility System Operations	Cyient, Inc.	Contract for Task Work 8-31-20
EPIC-3	Application of Advanced Metering Infrastructure (AMI) Data to Advanced Utility System Operations	Alliance for Sustainable Energy LLC – (Operator of the NREL)	Contract for Task Work 7-16-19
EPIC-3	Safety Training Simulators with Augmented Visualization	Oracle America, Inc.	Contract for Task Work 1-4-21
EPIC-3	Safety Training Simulators with Augmented Visualization	Oracle America, Inc.	Software License Associated with Above Task Work

Cycle	Project Name	Contractor	Contract Effective Date
			12-28-20
EPIC-3	Safety Training Simulators with Augmented Visualization	3D Internet	Contract for Task Work 10-23-20
EPIC-3	Safety Training Simulators with Augmented Visualization	Anser Advisory LLC	Contract for Task Work 9-7-21
EPIC-3	Demonstration of Multiple-Purpose Mobile Battery for Port of San Diego and Other Applications	Tesla, Inc.	Mobile Battery System Purchase 3-24-21
EPIC-3	Demonstration of Multiple-Purpose Mobile Battery for Port of San Diego and Other Applications	Quanta Technology LLC	Contract for Task Work 5-28-21
EPIC-3	Demonstration of Multiple-Purpose Mobile Battery for Port of San Diego and Other Applications	Anser Advisory LLC	Contract for Task Work 5-6-21

Five competitive procurements for EPIC-3 projects were launched in 2020, and resulting contracts were executed. SDG&E and the other EPIC Administrators are required to host at least two stakeholder meetings annually to discuss their EPIC programs, proposals, and progress.[2] Due to the COVID-19 pandemic, the annual EPIC Symposium was held as a virtual event on December 14-15, 2021. The Fall Workshop was held on November 17, 2021 and was also done as a virtual event.

SDG&E established and maintains an EPIC website accessible to the public: www.sdge.com/epic. This website provides EPIC program information and updates, as well as SDG&E's EPIC annual reports and comprehensive final project reports. It is also used to announce contractor bid opportunities.

[2] D.12-05-037 at 74.

II. SDG&E'S EPIC BUDGET AND RELATED COSTS

A. SDG&E Authorized Budget and Incurred Costs for EPIC-3 (2018-202)

Table 3 below, sets forth SDG&E's Commission-authorized EPIC budget incurred costs for EPIC-3 as of December 31, 2021.

Table 3. SDG&E Budget and Incurred Costs for EPIC-3 as of December 31, 2021 (in $ thousands)

	EPIC Triennial 3 (2021)	
	Technology Demonstration & Deployment	**Program Administrative**
SDG&E Commission-Authorized Budget[3]	8,852	916
SDG&E Incurred Costs[4] as of December 31, 2021	6,511	610

3 D.18-10-052 for EPIC-3.

4 Incurred costs mean actual booked expenditures.

Table 4 below, sets forth SDG&E's disbursements to the CEC and CPUC for EPIC-1, EPIC-2, and EPIC-3 as of December 31, 2021.

Table 4. SDG&E's Disbursements to the CEC and CPUC for EPIC-1, EPIC-2 and EPIC-3 as of December 31, 2021 (in $ thousands)

	EPIC Triennial 1 (2012 – 2014)		EPIC Triennial 2 (2015 – 2017)		EPIC Triennial 3 (2018-2020)	
	RD&D	Program Administrative	RD&D	Program Administrative	RD&D	Program Administrative
SDG&E Disbursements to CEC	16,127	3,024	40,624	2,991	45,396	2,673
SDG&E Disbursements to Commission for Regulatory Oversight	N/A	273	N/A	224	N/A	303

B. Commitments/Encumbrances[5,6] for TD&D Projects

SDG&E has committed $8,852k of its TD&D budget for the EPIC-3 cycle to four projects in its approved EPIC-3 application. As of December 31, 2021, SDG&E has committed $8,852k of EPIC-3 funds for contracted activities and in-house project work on these four projects. As of December 31, 2021, SDG&E has expended $5,480k on contracted work. SDG&E has spent $1,031k on internal project work. The total expenditures through December 31, 2021 on EPIC-3 TD&D project work are therefore $6,511k.

C. Commitments/Encumbrances for Program Administration

As of December 31, 2021, SDG&E has committed $916k for its EPIC-3 administrative budget.

D. Fund Shifting Above 5% between Program Areas

The utility EPIC Administrators are only allowed to fund EPIC projects in the TD&D program area. SDG&E has done no fund shifting to other program areas.

E. Uncommitted/Unencumbered Program Funds

SDG&E has committed all of its EPIC-3 TD&D funds to the four projects that were launched in 2019, with execution in 2021.

III. SDG&E EPIC-1 and EPIC-2 PROJECTS

All EPIC-1 and EPIC-2 projects were completed in earlier years. The comprehensive final project reports were delivered with prior annual reports and are posted on SDG&E's public website at www.sdge.com/epic. There are no updates for those projects to be reported for 2020 and 2021.

IV. SDG&E EPIC-3 PROJECTS

This section provides a detailed description and status report for the active and completed EPIC-3 projects.

A. Project 3: Application of Advanced Metering Infrastructure (AMI) Data to Advanced Utility System Operations

- **Investment Plan Period - 2018-2020 (EPIC-3)**
- **Assignment to Value Chain - Distribution**

[5] Commitment means assigned for anticipated work on a project, including anticipated contractual commitments, equipment purchases, software licenses, associated technical work by the SDG&E project team, and other expenses directly associated with the project work.

[6] Encumbrances are funds that are specified for contracts (D.13-11-025 at 101; Ordering Paragraph 45) or for in-house work necessary in collaboration with a contractor (D.13-11-025 at 53). They differ from commitments in that commitments are the identification of blocks of funds to be assigned to projects, whereas encumbrances specify how the commitments will be used in the projects.

- **Objective**

The objective of this project was to perform pre-commercial demonstrations of critical capabilities for leveraging SDG&E's AMI system with its 1.4 million endpoints to provide actionable secondary voltage data and analysis to SDG&E and other prospective users.

- **Scope**

The pre-commercial demonstration work was focused in two modules:

- **Module 1: AMI System as a Voltage Sensor Network**

This module was performed as part of a Cooperative Research and Development Agreement (CRADA) with the National Renewable Energy Laboratory (NREL). The primary focus of the module was to demonstrate and evaluate the capabilities of AMI-based controls for distribution system operations, including monitoring and control at the secondary transformer level using existing AMI infrastructure. In other words, in commercial use the grid-edge monitoring systems and controls provided by the third- party vendors (procured by SDG&E) would perform grid operations using AMI data. The module scope also included efforts for developing and validating models that are representative of real SDG&E feeders in a distribution simulation environment. These models were tuned and validated using AMI data collected from the field to produce accurate feeder models. Moreover, a demonstration compromising of control use case scenarios, performance metrics and evaluation procedures was performed.

- **Module 2: Phase Identification**

Visibility into the physical state of the distribution system and its real-time load flow conditions is required to advance grid modernization. Accurate phasing information is essential for optimal control and effective operation of a utility distribution system with modernization functions such as advanced distribution management system (ADMS) and distributed energy resource management system (DERMS) platforms. Thus, it is becoming more important to have accurate information (i.e., phase identification) of the distribution network to be able to effectively manage/control it. This module demonstrated the application of AMI data to automatically identify phasing information within SDG&E distribution system.

- **Deliverables**

Two comprehensive final reports were completed, including thorough documentation of the module approaches, demonstration results, final benefits estimate, value proposition, and recommendations regarding commercial adoption.

- **Metrics**

This section provides more information about the metrics and benefits of the project, which were analyzed in the demonstration work. The most important benefits are in areas of:

- **Safety, Power Quality, and Reliability**

    a. Ability to monitor, visualize, and analyze visualization information can help reduce number of outages, as well as their frequency and duration. The transmission fault location use case is particularly beneficial for this purpose.

    b. Public safety improvement and hazard exposure reduction can also be accomplished by advanced visualization tools, for example, in the AMI for operations use case, where the voltage swell and sag are visually monitored. This application is used for monitoring in emergency scenarios, such as Red Flag Warnings and earthquakes.

    c. Improved access to AMI data and awareness company-wide. For example, in the load curtailment visualization use case, the load curtailment is visually represented to help users visualize the curtailment locations and details as data on a map. This is expected to be beneficial in emergencies.

- **Effectiveness of Information Dissemination**

    a. The visualization platforms will enable the creation of numerous reports and fact sheets for various users.

- **Schedule - January 2019 to December 2021**
- **EPIC Funds Committed - $1,800k**
- **EPIC Funds Spent as of December 31, 2021 - $1,521k**
- **Partners (if applicable) - National Renewable Energy Laboratory (NREL) in Module 1.**
- **Match Funding (if applicable) – NREL $400k**
- **Match Funding Split (if applicable) – 50/50**
- **Funding Mechanism (if applicable)**

SDG&E EPIC funds applied to a combination of internal work and pay-for-performance contracts. Cost share by National Renewable Energy Laboratory (NREL).

- **Treatment of Intellectual Property (if applicable) - No IP developed**
- **Status Update**

The SDG&E and NREL team completed execution of the pre-commercial demonstration, data gathering, and analysis of results. The project activities and results were incorporated into a comprehensive final project report written and finalized in the third and fourth quarters of 2021. Module 1 focused on using AMI data for a voltage sensor network. NREL assisted SDG&E in demonstrating the tools and strategies for using the AMI-based field measurements for distribution system monitoring and planning. The use cases identified for Module 1 included:

- PV Smart Inverter Study – The impact of various smart inverter settings on selected SDG&E feeders was examined
- Utility Planning Network Model Anomaly Detection Tool – An automated tool was demonstrated that uses the AMI measurement data to identify the inaccuracies in the network model used for distribution planning.
- Phase Identification Tool – A tool was demonstrated that performs automated phase mapping of the AMI meters based on AMI data.
- Meter to Transformer Mapping – The demonstration of a proof-of-concept AMI meter-to-service transformer mapping solution that identified incorrect records based on AMI measurement data was performed.

It was recommended that SDG&E apply specific tools to other feeders as the use cases presented in this project demonstrated the accuracy, feasibility, and rationality for greatly improving planning and operations activities, especially for feeders with high levels of PV adoption. More information is provided in the EPIC-3, Project 3 Module 1 Final Report included in the appendix of this document and posted to the SDG&E public website at www.sdge.com/epic.

In Module 2, a competitive procurement was carried out to select vendor tools for demonstration and evaluation. SDG&E teamed with these vendors to carry out the demonstration work.

SDG&E internal and vendor methodologies were developed, and demonstrations were conducted in 2021. Final project reports were completed by each vendor and the internal SDG&E team. An integrated final project report was created that includes each of the methodologies demonstrated and a summary of the results.

The focus of Module 2 was using AMI data to identify endpoint phasing and meter-to-transformer mapping. Three distinct methodologies leading to demonstrations were completed to determine the feasibility of executing two use cases:

- AMI meter phasing

- Meter-to-transformer mapping while constraining the AMI input source to two meters per transformer

Based on the pre-commercial demonstration results and findings of this project, the key recommendation is to identify additional use cases that use AMI data, and then to pursue an application or suite of applications that can fulfill them.

More information is provided in the EPIC-3, Project 3 Module 2 Final Report included in the appendix of this document and posted to the SDG&E public website at www.sdge.com/epic.

B. Project 4: Safety Training Simulators with Augmented Visualization

- **Investment Plan Period - 2018-2020 (EPIC-3)**
- **Assignment to Value Chain – Distribution**
- **Objective**

The project demonstrated and evaluated simulation and augmented reality applications for field focused design, operations, and asset monitoring and management solutions. It demonstrated the ability of the latest simulator technologies to train utility industry personnel on safety related issues, such as electric potential zones and grounding techniques associated with construction work practices. Demonstrated capabilities included the utilization of augmented reality tools to visualize and provide rich contextual information at the point of work.

- **Focus**

EPIC-3 Project 4 was divided into two modules. The first module focus was to conduct a pre-commercial demonstration of a functioning fault location system, that will be utilized to create a training stimulator for electric distribution system operators and other prospective users. The system integrated inputs from multiple sources.

The second module was focused on demonstrating use of virtual-reality visualization tools to aid in training field employees in safe practices for working in situations where there is the possibility of unexpected hazardous levels of electric potential.

- **Scope**
- **Module 1: Focused Patrol Simulator**

The scope of this module was to demonstrate a functioning precommercial training simulator that can help system operators and operator trainees narrow the location of a fault during a real or simulated power outage for a set of selected test circuits. This new training environment was utilized to teach the system operators/trainees to recognize, understand and utilize the signals from Wireless Fault Indicators (WFI's), existing SCADA capable devices, and upgraded Smart Meters.

A reconfigured advanced distribution management system (ADMS) built-in algorithm for accurately predicting the region of a fault handled the integration. Minimizing the fault location process and allowing operators to more strategically dispatch fewer, more-focused field personnel to the scene provided the following benefits:

- **Safety to SDG&E's Personnel**

  Because the Training Simulator was based on a more efficient approach for determining fault location and directing field personnel to the fault location, it inherently improved safety for field personnel, reducing their driving exposure into more rural areas and sometimes dangerous weather conditions.

- **Safety to the Public**

  The new training process and improved field equipment, allowed the operator trainees to find wire down events quicker, reducing public exposure to a potentially energized system. Any system that hastens service restoration inherently improves safety to the public, ensuring local infrastructure operates as intended (e.g., communications and water systems and traffic signals), after faults of any type cause service interruptions.

- **Risk Reduction**

  As the fault location was identified quicker, and the correct personnel deployed accurately and faster to that location, the new capability:

  - Enabled the organization to be better prepared for the future, by offering more measures to mitigate/decrease the risk of starting fires due to wire down or possibly other events, thus reducing the overall risk that the company and its customers face as it relates to wildfire.

  - Reduced the need for test closures, making a more resilient utility by extending the life cycle of distribution equipment.

- **Reduced Cost**

  Focused patrol training allowed for a quicker fault identification, effectively reducing the duration of power interruption and therefore reducing the overall System Average Interruption Duration Index (SAIDI) impact of outages, making SDG&E a more reliable provider. It will also increase customer satisfaction and reduce their exposure to wildfire-related and other risks associated with outages.

  This training module will naturally lead to process improvements, which will allow a utility to do the same job with fewer resources (i.e.: if the location of the fault is determined more quickly, personnel can be deployed to the location more quickly, and released from duty earlier, or assigned to subsequent tasks if needed).

- **Module 2: Personal Protective Grounding/Equal Potential Zone (PPG/EPZ) Simulated Training**

  The scope of this module was to demonstrate a Virtual/Augmented Reality (VR) precommercial training stimulator for PPG/EPZ on the electric distribution underground (UG) system. This new training system was used for students initial and/or refresher compliance training to enhance understanding of the procedures for PPG/EPZ. With the energized test yard at SDG&E's training center, the VR was tested to see how efficient/effective the training with the VR was compared with current practice. The case for prospective commercial adoption of the training was examined. The following benefits were evaluated:

  - **Safety to SDG&E's Personnel**

    a. With the VR simulator, SDG&E was able to provide initial and refresher training to more employees on the proper procedures of doing PPG/EPZ work on the UG distribution system.

    b. The energized test yard played a role in helping to physically demonstrate the work methods unique to EPZ/PPG deployment, so that those methods could be accurately displayed in the VR environment.

  - **Safety to the public**

    With the VR training put into practice, SDG&E was able to restore simulated power to the customer more quickly and safely and reduce public exposure to a potentially energized system.

- **Risk reduction**

  The VR training simulator helped protect employees from back-feed from privately-owned generation sites (malfunctioning solar systems, incorrectly connected small generators, etc.)

- **Reduced Cost**

  The training helped reduce outage times and associated costs. The training itself was accomplished at a lower cost than current practice.

- **Deliverables**

Comprehensive final reports, including thorough documentation of the module approaches, demonstration results, final benefits estimate, value proposition, and recommendations regarding commercial adoption.

- **Metrics**

- **Module 1**

  - A key metric is shorter SAIDI minutes for outages because of quicker fault location identification.

  - Another key metric is reduced usage of test closure to identify fault location, and the resulting longer asset life, and improved power quality.

  - The ultimate key metric is the effectiveness of the training simulator in achieving improved operating practices that result in achieving the above metrics. There was a task that tested the capture of learning by those taking the training.

  - A quantitative basis for valuation of the above metrics was used in the analysis phase of this project module. Additional benefits of commercial adoption may also be identified the simulator is applied.

- **Module 2**

  - A key metric that was used is the safety of the employees, in the context of back feed from customer generation (distributed energy resources).

  - Another key metric was the expected reduction of outage times and injuries attributable to the training. The ultimate key metric was the general effectiveness of the training simulator, compared to current practice.

- **Schedule - January 2019 to December 2021**
- **EPIC Funds Committed - $2,100k**
- **EPIC Funds Spent as of December 31, 2021 - $1,988k**
- **Partners (if applicable) - n/a**
- **Match Funding (if applicable)**

None. However, SDG&E made its energized test yard available for the demonstration.

- **Match Funding Split (if applicable) - n/a**
- **Funding Mechanism (if applicable)**

SDG&E EPIC funds were applied to a combination of internal work and pay-for-performance contracts. Two RFPs were released in 2020. Two vendors were selected to work with the SDG&E team. The contracts for Module 1 were awarded in late 2020 and early 2021. One contract for Module 2 was awarded in 2020 and a contract to complete the final project report was awarded in 2021.

- **Treatment of Intellectual Property (if applicable) - No IP developed.**
- **Status Update**
- **Module 1**

SDG&E chose the circuits for this demonstration. SDG&E chose the methodology used to identify the strategic location where the WFI's were installed (simulated or real). Concurrently to the WFI task, the team made updates to the electrical system data which eventually led to the ADMS having values that mirror more closely our current protection software and data. SDG&E had all the updates completed by early 2021.

Minor adjustments to the company's AMI network were accomplished to help accommodate the new feature.

After sufficiently scoping and describing the work tasks, SDGE issued an RFP in 2020 securing a contractor to work with SDGE internal staff. Contract executions occurred in late 2020 and early 2021. The bulk of the contracted work occurred in Q2 through Q4, with the final report being drafted, edited, and finalized by the internal and contractor team by the end of the year. The ultimate outcome of the project was a recommendation to pursue commercialization to provide long term benefits in terms of safety, reliability, and student learning outcomes.

- **Module 2**

SDG&E used internal staff as the subject matter experts performing the project work and hired a software vendor to provide a capability to demonstrate PPG/EPZ training practices. An energized test yard was augmented to provide a facility to evaluate how well the VR compares to current practice. The yard also served as a safe demonstration site for the VR software vendor to visualize the necessary work tasks, for accurate and faithful simulation.

The vendor was selected by a Request for Proposal (RFP) process, and a contract was awarded to one of the bidders to work with the SDG&E team in performing the demonstration. The test yard was completed in the 2020 calendar year. The demonstration has now been completed.

Module 2 was successfully completed, and the final report drafted, edited, and finalized, by year end. The ultimate outcome was a recommendation for commercialization of the software, to ensure long term improvements in student learning outcomes, as new operator trainees enter the program to become fulltime, fully qualified system operators.

C. Project 5: Unmanned Aircraft Systems (UAS) With Advanced Image Processing for Electric Utility Inspection and Operations

- **Investment Plan Period – 2018-2020 (EPIC-3)**
- **Assignment to Value Chain - Transmission / Distribution**
- **Objective**

The project demonstrated new applications of unmanned aircraft systems ("UAS") with enhanced image processing capabilities for electric operations. The project target was to define, demonstrate and evaluate concepts for instrumentation and monitoring of the power system equipment using enhanced imaging on UAS and sensor technology. The project evaluated the potential to increase reliability, safety and cost efficiency to improve power system operations.

- **Focus**

The focus of this project was to demonstrate practical applications of UAS that have strong implications for worker safety, system reliability, data collection and storage, and improved decision making in operations. The project followed a logical structure to capture, process, analyze, and share information using UAS.

- **Scope**

Define, demonstrate and evaluate concepts for instrumentation and monitoring of the power system equipment using enhanced imaging on UAS and sensor technology. Evaluate the potential to increase reliability, safety and cost efficiency to improve power system operations and thereby add value to customers.

Nine benefit areas were studied:

1. Improved sensor technologies (i.e., LiDAR and Corona camera) monitor power system equipment with more accuracy and provide better photo documentation.

2. Night flights and beyond line of sight (BLOS) operations provide more long-range inspection and documentation opportunities – improved modern methods of data collection.

3. Improved worker safety – fewer near-miss accidents and reduced potential OSHA reports such as accidents, worker's comp, and other paid leave.

4. Increased power system reliability, safety, and cost efficiencies – improved operations and higher cost savings.

5. Advanced imaging provides more efficient disaster response times, reporting, and re-energization of patrols after a site is deemed all-clear.

6. Support for vegetation management – reduces potential for wildfires.

7. Ability to efficiently identify corrosion on equipment.

8. Improved long-term planning – ability to determine the status of scenarios as-is versus how they should be.

9. Supporting and increasing staff efficiencies of 9 departments including:

    - Aviation Services Department (ASD)
    - Electric Distribution Engineering (EDE)
    - Distributed Energy Resources (DER)
    - Fire Risk Mitigation (FiRM)
    - Fire Science and Coordination
    - Transmission, Construction & Maintenance (TCM)
    - District Operations & Engineering (O&E)
    - Wildfire Mitigation (WMP)
    - Emergency Services (ES)

- Environmental
- Planning

The demonstration targeted multiple use cases:

- **Use Case 1** - Telepresence software was demonstrated which would provide teams with the ability to integrate drones into their operational workflows--both systems and personnel. Experts can participate from their office, which limits equipment and personnel on- site. Evaluation of repair needs can be done remotely and assess risk before any personnel arrive on site. Live video feeds can be shared with management or any other employee via weblink.
- **Use Case 2** – Beyond line of sight (BLOS) is not currently normal in UAS operations in the United States. The pros and cons of investing in BLOS were assessed in the project.
- **Use Case 3** – The use case explored night flights in support of Public Safety Power Shutoff (PSPS) and wildfire mitigation. This includes robust efforts to fire harden the power system, enhance situational awareness, update operating protocols and build community partnerships to improve the region's overall ability to respond to wildfire. SDG&E has 25 drones to assess infrastructure working in conjunction with CalFire as needed. The EPIC project work benefits from the past buildup of these capabilities.
- **Use Case 4** –Testing of a Corona camera on a UAS to detect corona was initiated. Corona is a luminous partial electrical discharge due to ionization of the air. Corona causes faulty components of the network, RF interference and audible noise. Corona will appear when the local electric field exceeds a critical value. The ultraviolet emission can be visualized with a daylight corona ultraviolet camera.
- **Use Case 5** – Testing of a tethered UAS was completed. Tethering could provide unlimited flight time and would be ideal in an emergency situation. It could provide situational awareness when using the Tactical Command Vehicle (TCB).
- **Use Case 6 –** Line pulling utilizing a UAS could assist with new construction in high vegetation areas or areas not permitted for low elevation manned aircraft flights. This would lower the potential risk and avoid asking residents to leave their house, as would be required per the FAA.

6. Deliverables

A comprehensive final report, including thorough documentation of the project approach, demonstration results, final benefits estimate, value proposition, and recommendations regarding commercial adoption.

7. Metrics

Example metrics for determining the value proposition of the use cases are:

- **Use Case 1** –Metrics include examining the value proposition for having the ability to live stream video feed to any department during an emergency. This could have immediate cost savings in eliminating the need to have multiple departments out in the field. It would also reduce the number of employees at a job site.
- **Use Case 2** – This use case was discontinued as explained below under Status Update. The metrics were to determine the pros, cons, and value proposition for BLOS UAS applications through demonstration work.
- **Use Case 3** - UAS operations procedures during Red Flag Warnings were created to include a work shift schedule due to Public Safety Power Shutdowns (PSPS). Before and after PSPS, UAS crews will support inspecting overhead power lines to check for debris and equipment damage prior to event or to re-energizing lines. Demonstration work is targeted at determining the value proposition for full integration of UAS night patrols in a PSPS event and being able to bring power back to a customer in a faster and less costly manner.
- **Use Case 4** – The metrics are to compare the cost of using a corona camera on a UAS versus traditional practice and confirm the value proposition for the former.
- **Use Case 5** -- The metric is the extent of increased situational awareness during emergency events and having a UAS that can stay airborne as long as it has power, without battery changes or charging needed. This system can be utilized alongside of the TCV or a standalone unit using a generator as a power source.
- **Use Case 6** – Commercial success for this use case would be to utilize this tool in any high vegetation areas or areas where manned aircrafts are not desired or allowed due to the low flight elevation, if the value proposition is determined to be great enough during this pre-commercial demonstration project.

8. Schedule - January 2019 to October 2021

9. EPIC Funds Committed - $729k

10. EPIC Funds Spent as of December 31, 2021 - $693k

11. Partners (if applicable) - N/A

12. **Match Funding (if applicable) - N/A**

13. **Match Funding Split (if applicable) - N/A**

14. **Funding Mechanism (if applicable)**

SDG&E EPIC funds applied to a combination of internal work and pay-for-performance contracts.

15. **Treatment of Intellectual Property (if applicable) - No IP developed**

16. **Status Update**

- **Use Case 1 –** Negotiations with a vendor to provide the needed capability were completed. Some issues were identified during the demonstration that may be resolved with the 5G network.
- **Use Case 2**- After research on companies that were conducting BLOS operations, a vendor was contacted who has experience with assisting other businesses in obtaining BLOS approval from the FAA. Ultimately, SDG&E decided not to pursue a BLOS waiver from the FAA due to expense and changing regulations. The use case was discontinued in the EPIC project.
- **Use Case 3 -** This approach was deemed successful and commercially viable during five different demonstration trials, including both pre- and post-PSPS events. The use case was adopted for commercial use with seven hard-to-access areas identified for PSPS patrols using UAS.
- **Use Case 4 -** As of Aug 2019, SDG&E was the first company in the United States to fly a corona camera on a UAS with the support of a local vendor integrating the camera on a UAS. SDG&E completed five successful test flights on August 19-20, 2019 and again on September 12, 2019 and assessed twelve 230kV tower structures. Testing was conducted and efforts to integrate the procedures into the regular workforce operations were completed. All corona inspectors were trained to use this tool daily as needed.
- **Use Case 5** - Demonstration of a tethering UAS was conducted in 2020 with a vendor and produced mixed results. Battery issues arose with the demonstration unit, and it did not work properly. This was a new product offering, and it did not appear to be working as advertised. A different vendor was found with a system that worked and tested successfully. The unit was purchased and delivered in December 2020; and training occurred in January 2021. Testing continued in 2021 followed by commercial adoption.
- **Use Case 6** – Line pull testing began in mid-2020 using a UAS. Mule tape, jet line and pull strings were tested before actual operations.

This technique was found to be successful three times during 2020. Since mid-2020, there have been multiple requests from within the company to use this capability. After continued project demonstrations performed in 2021, the line pulling use case was determined as high-value and is in commercial use.

Given the successes of this EPIC project, it is recommended that additional work be done to further evaluate and expand use of these UAS technologies and use cases to identify others that can be used commercially in future utility system operations. The final project report is provided in this document's appendix and is posted to SDG&E's public website at www.sdge.com/epic.

D. Project 7: Demonstration of Multi-Purpose Mobile Battery for Port of San Diego and/or Other Applications

- **Investment Plan Period - 2018-2020 (EPIC-3)**
- **Assignment to Value - Distribution (primary) and Demand-Side Management (primary)**
- **Objective**

The objective of this project was to undertake a pre-commercial demonstration of a mobile battery system. The project examined the possibilities for using a mobile battery at its home base (tentatively the Port of San Diego ("District")) and at secondary energy hubs (such as SDG&E substations or large customers) within the service area. The project evaluated stacking of various benefits that can be derived from a mobile battery, when rotated between multiple locations. The battery was used at a District's tenant, Marine Group Boat Works, and in other applications at other locations. The objective was to evaluate the effectiveness of mobile batteries when rotated between applications and identify preferred applications and strategy for the rotation.

- **Focus**

The focus of this project was to conduct a pre-commercial demonstration, showcasing the concept of mobile utilization of a containerized battery energy storage system (BESS) for various use cases and locations. Ultimately, the project sought to determine the effectiveness and value proposition from the stacking of benefits when rotating MBESS between applications and identifying which are preferred and most feasible for commercialization.

- **Scope**

While mobile batteries are commercially available on a limited basis, the mobile utilization of the same asset in various use cases and applied at multiple locations is new.

Therefore, the benefits of adopting such technology needed to be demonstrated and evaluated. To better approach the demonstration, this project was devised into two modules.

- **Module 1 – San Diego Unified Port District (referred to as "the District"):**

A primary issue for commercial and industrial businesses within the District is low load usage yet high peak demand for relatively short periods, which results in undesirable energy demand charges. This project demonstrated a new solution to assist the District and other surrounding energy hubs in alleviating these problems. Pursuing a more traditional solution for load factor improvements has proven to be challenging due to geographical restrictions for the District.

While the original intent was for a MBESS deployment at the cruise ship terminal at the Port of San Diego, a variety of factors made deployment at this site infeasible during the pre-commercial demonstration window. So, another site, with similar load trends, was chosen as one of two deployment sites. Ultimately, MBESS deployment was moved between the Marine Group Boat Works and Cameron Corners Microgrid sites to demonstrate the stacked benefits of multiple use cases across various sites.

A single vendor was selected through competitive procurement to provide a 362kW/1499kWh battery, as well as provide support during commissioning tests and deployments. A second vendor was selected to provide engineering support throughout the demonstration, perform data analysis, and prepare a comprehensive final report for Module 1.

- **Module 2 – Community Resource Center (CRC):**

As an additional application, a smaller mobile BESS was considered for demonstration as a backup power solution during emergency response situations such as wildfires and other calamities. In anticipation of extended power outages, such as public safety power shutoffs (PSPS), SDG&E may request activation of a CRC in affected areas. These facilities offer resources for residents such as water and food supply, electronic device charging, and outage information updates.

Enhancing the resiliency of these communities will contribute to the accessibility of resources for affected customers.

- **Benefit Areas:**
- Reduced emissions of greenhouse gases - augment the use of traditional generation by use of an MBESS. Use of infrastructure such as a MBESS helps to offset periods of heavy localized electric power demand in

support of the Port of San Diego's Climate Action Plan.

- Improved reliability and system performance – directly mitigate the duration and frequency of any service disturbances (i.e., voltage fluctuation, flicker, and harmonics) and/or interruptions (planned or unplanned) to the customer.

- Improved electric system efficiency – reduce power losses (I^2R) in the system by placing a power supply source closer to customer load.

- Increased utilization of the mobile battery asset, flexibility to assist in multiple use cases, and ability to more effectively react in real-time.

- **Use Cases:**

The demonstration tested the mobile battery for use in functions such as demand shaving, emergency energy supply, voltage regulation, and frequency regulation at the various energy hubs.

- **Reducing End-Use Consumer Demand Charges**: Large power consumers such as commercial and industrial facilities, including the District, can reduce their electricity demand charges, which are generally based on the facilities' highest observed rates of electricity consumption during peak periods, by using on-site energy storage during peak demand times.
- **Peak Shaving**: Shifting portions of electricity demand from peak hours to other times of day also reduces the amount of higher-cost, seldom-used generation capacity needed to be online, which can result in overall lower wholesale electricity prices.

- **Voltage Regulation**: Batteries can help control voltage and frequency on multiple time scales (by the second, minute, or hour). In particular, fast-ramping batteries are well suited to provide such ancillary grid services as voltage and frequency regulation. Overall, this helps maintain the grid's electric frequency optimizing the performance of the system.

- **Back-Up Power**: Batteries can provide back-up power to load pockets such as households, businesses, and CRCs. The back-up power capability not only supports electric reliability efforts but also ensures customer needs are met. Ideally, the BESS can seamlessly provide uninterrupted power when distribution services are temporarily deenergized and electrically separated from the utility system.

- **Deliverables**

Comprehensive final reports for each project module, including thorough documentation of the project approach, demonstration results, final benefits estimate, value proposition, and recommendations regarding commercial adoption.

- **Metrics**

The project metrics were tracked through milestones marked by completion of project plan tasks. Specific value metrics for the project were measured by comparative analysis, utilizing current base practices and historical data (i.e., customer load demand and profile, net energy metering, power quality metering, energy consumption algorithms and calculations, and emissions reporting.), collecting new data through application of the mobile battery system, comparing the data specific to each use case, and analyzing the benefits.

- **Schedule - January 2019 to December 2021**
- **EPIC Funds Committed - $4,223k**
- **EPIC Funds Spent as of December 31, 2021 - $2,309k**

Purchase of the mobile batteries and demonstration work was fully executed.

- **Partners (if applicable)**

San Diego Unified Port District tenant, Marine Group Boat Works, and other customer site hosts.

- **Match Funding (if applicable)**

Not applicable.

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

Not applicable.

- **Funding Mechanism (if applicable)**

SDG&E EPIC funds applied to a combination of internal work and pay-for-performance contracts.

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

No IP developed.

- **Status Update**
- **Module 1**

Competitive procurement for the Module 1 battery was conducted in early 2020, and a contract was awarded to provide an MBESS in March 2021. Initially, the Port of San Diego cruise ship terminal was selected as a location for battery demonstration, but it was later determined a variety of factors made deployment at this site infeasible during the pre-commercial demonstration Instead, the battery was brought to Marine Group Boat Works (MGBW), a Port of San Diego tenant, and to SDG&E's Cameron Corners Microgrid (CCM) site in Campo, CA. At MGBW, use cases like load smoothing, peak shaving, and other tests were successfully performed, and results are laid out in the final report. At CCM, the mobile battery successfully islanded the customers downstream of the microgrid yard, which was augmented by using generators for a total duration of 23 hours. The demonstration work was completed in the 3rd and 4th quarter of 2021.

- **Module 2**

Competitive procurement for the Module 2 battery system and engineering services was conducted and awarded in 2021. A single contractor was selected to supply both the battery and engineering services. After receiving the battery and conducting commissioning tests, the battery was rotated to two CRCs in areas that are highly susceptible to PSPS. It ran for 24 hours at each location to ensure the battery can provide power reliably and for a long period of time. The demonstration work was completed in the 4th quarter of 2021.

All findings for each module were included in their respective comprehensive final reports. These final project reports are included in the appendix of this annual report and are posted on the SDG&E EPIC public website at www.sdge.com/epic.

The ultimate outcome from this demonstration work is that it is recommended that SDG&E pursue commercial adoption of MBESS. However, there will be more use cases evaluated and demonstrated in 2022 to continue evaluating the commercial value proposition of MBESS. This added use case work will be called Module 3 and will have its own comprehensive final report. Module 3 will be the final module of the project.

V. CONCLUSION

A. Key Results for 2021 SDG&E EPIC Program

As of December 31, 2018, SDG&E had completed all technical project work for its 11 Commission-approved EPIC-1 and EPIC-2 projects. No projects were completed in 2019 and 2020. In 2021, three EPIC-3 projects were completed, and two modules of a fourth project were completed. Seven comprehensive final project reports were completed in 2021 and are included with this annual report. Past EPIC comprehensive final project reports are available on the SDG&E EPIC website at www.sdge.com/epic.

Major accomplishments in 2021, included performing the demonstration work, data analysis, formulation of findings and recommendations regarding commercial adoption, and preparation of the comprehensive final project reports for the three projects and two modules of a fourth project that were completed. The PICG was continued, and SDG&E supported and contributed to the EPIC database development and other activities that were organized by the CPUC's PICG coordinator.

B. Next Steps for SDG&E's EPIC Program

Three of the EPIC-3 projects were completed in 2021 and two modules of a fourth project were completed. Additional use cases will be performed in the unfinished project by adding a Module 3 for the purpose. Module 3 will be performed in 2022, and that will provide closure on the entire EPIC-3 cycle.

An EPIC-4 cycle was ordered by CPUC in late 2021.[1] Starting in 2022, SDG&E will engage in the launch processes for EPIC-4, as prescribed by CPUC.

[1] D. 21-11-028.

ATTACHMENT B

SDG&E 2021 Annual Report Project Status Spreadsheet (Excel file follows)

Attachment B - San Diego Gas Electric Company - 2019 EPIC Project Status Report

Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project (objective; scope; deliverables; schedule)	Date of the Award	Was project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($000)	Committed Funding Amount ($000)	Funds Expended to date: Contract/Grant Amount ($000)	Funds Expended to date: In-house expenditures ($000)	Funds Expended to date: Total Spent to date ($000)	Administrative and overhead costs to be incurred for each project	Leveraged Funds	Partners	Match Funding	Match Funding Split	Funding Mechanism
3rd Triennial (2020)	SDG&E	**PROJECT 3: Application of Advanced Metering Infrastructure (AMI) Data to Advanced Utility System Operations**	Pre-commercial Demonstration	This project is performing pre-commercial demonstrations of two critical capabilities (towards modernization) for leveraging SDG&E's AMI system with its 1.4 million endpoints to provide actionable secondary voltage data and analysis to SDG&E and other prospective users. The project is subdivided into multiple work modules. A comprehensive final report was delivered for each major module. Schedule - Jan 2019 - Dec 2021.	Module 1: July 16, 2019 for NREL CRADA Module 2: Aug. 31, 2020 for Cyient and Oct 31, 2019 for Itron	Yes for two contracts and no for a pending contract	Distribution	**1,800**	**1,800**	**1,126**	**395**	**1,521**	N/A	400k	National Renewable Laboratory (NREL)	400k	50/50	SDG&E EPIC funds applied to a combination of in-house work and pay-for-performance contracts. Plus NREL co-funding in Module 1.
3rd Triennial (2020)	SDG&E	**PROJECT 4: Safety Training Simulators with Augmented Visualization**	Pre-commercial Demonstration	The project is demonstrating and evaluating augmented reality applications for field focused design, operations, and asset monitoring and management solutions. This project is divided into two modules: "Training Environment for System Operators Allowing Focused Patrol of Overhead Distribution" and "Personal Protective Grounding/Equal Potential Zones (PPG/EPZ) Training on the Electric Distribution Underground System". A comprehensive final report will be delivered for each module. Schedule - Jan 2019 - Dec 2021.	Module 1: Oracle contracts executed 12/28/20 and 1/4/21. Module 2: Contracts executed with 3D Internet on Oct. 23, 2020, and with Anser Advisory Sept.7, 2021.	Yes for Module 1 and No for Module 2, for which there is a pending contract	Distribution	**2,100**	**2,100**	**1,686**	**302**	**1,988**	N/A	0	0	0	NA	SDG&E EPIC funds applied to a combination of in-house work and pay-for-performance contracts.

Project status information for EPIC-1 and EPIC-2 was included in prior annual reports and is not included above, because the projects were completed in prior years.

Attachment B - San Diego Gas Electric Company - 2019 EPIC Project Status Report

Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project (objective; scope; deliverables; schedule)	Date of the Award	Was project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($000)	Committed Funding Amount ($000)	Funds Expended to date: Contract/Grant Amount ($000)	Funds Expended to date: In-house expenditures ($000)	Funds Expended to date: Total Spent to date ($000)	Administrative and overhead costs to be incurred for each project	Leveraged Funds	Partners	Match Funding	Match Funding Split	Funding Mechanism
3rd Triennial (2020)	SDG&E	**PROJECT 5: Unmanned Aircraft Systems (UAS) with Advanced Image Processing for Electric Utility Inspection and Operations**	Pre-commercial Demonstration	The project demonstrated new applications of Unmanned Aircraft Systems ("UAS") with enhanced image processing capabilities for electric operations. The project defined, demonstrated and evaluated concepts for instrumentation and monitoring of the power system equipment using enhanced imaging on UAS and sensor technology. The project evaluated the potential to increase reliability, safety and cost efficiency to improve power system operations. A comprehensive final report was delivered at the end of 2021. Schedule - Jan 2019 - Dec 2021.	None to date; all work done internally	NA	Transmission and Distribution	**729**	**729**	**645**	**48**	**693**	N/A	0	0	0	NA	SDG&E EPIC funds applied to a combination of in-house work and test equipment purchases.
3rd Triennial (2020)	SDG&E	**PROJECT 7: Demonstration of Multipurpose Mobile Battery for Port of San Diego and/or Other Applications**	Pre-commercial Demonstration	The objective of this project was to undertake a pre-commercial demonstration of a mobile battery system. The project examined the possibilities for using a mobile battery at its home base (tentatively the Port of San Diego ("Port")) and at secondary energy hubs within the service area. The project evaluated stacking of various benefits that can be derived from a mobile battery, when rotated between multiple locations. The project was structured in two work modules involving different mobile battery sizes and applications. A comprehensive final report was delivered at the end of 2021. Schedule - Jan 2019 - Dec 2021.	Module 1: Tesla contract was executed March 24, 2021 and Anser Advisory, May 6, 2021. Module 2: Contract executed with Quanta on May 28, 2021.	NA	Distribution and Demand-Side Management	**4,223**	**4,223**	**2,023**	**286**	**2,309**	N/A	0	0	0	NA	SDG&E EPIC funds applied to a combination of in-house work and pay-for-performance contracts.
			3rd Triennial (2018 - 2020) - Current Financial Totals as of December 31, 2021					**8,852**	**8,852**	**5,480**	**1,031**	**6,511**						

Project status information for EPIC-1 and EPIC-2 was included in prior annual reports and is not included above, because the projects were completed in prior years.

Attachment B - San Diego Gas Electric Company - 2019 EPIC Project Status Report

Investment Program Period	Program Administrator	Project Name	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.	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization. (This column is applicable to the CEC only.)	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 (This column is applicable to the CEC only.)
3rd Triennial (2020)	SDG&E	**PROJECT 3: Application of Advanced Metering Infrastructure (AMI) Data to Advanced Utility System Operations**	No	Sole source and RFP	Module 1: NREL was sole sourced. Module 2: Two bidders passed initial screening.	Module 2: Cyient and Itron	Rank 1 (Highest)	NA	N/A	No	N/A
3rd Triennial (2020)	SDG&E	**PROJECT 4: Safety Training Simulators with Augmented Visualization**	No	RFPs in 2020	Module 1: Three bidders passed initial screening. Module 2: Three bidders passed initial screening	Module 1: Oracle. Module 2: 3D Internet.	Both modules: selected highest ranked bidders in the respective RFPs.	NA	N/A	No	N/A

Project status information for EPIC-1 and EPIC-2 was included in prior annual reports and is not included above, because the projects were completed in prior years.

Attachment B - San Diego Gas Electric Company - 2019 EPIC Project Status Report

Investment Program Period	Program Administrator	Project Name	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.	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization. (This column is applicable to the CEC only.)	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 (This column is applicable to the CEC only.)
3rd Triennial (2020)	SDG&E	**PROJECT 5: Unmanned Aircraft Systems (UAS) with Advanced Image Processing for Electric Utility Inspection and Operations**	No	Sole source for test equipment purchases only.	NA	NA	N/A	N/A	N/A	No	N/A
3rd Triennial (2020)	SDG&E	**PROJECT 7: Demonstration of Multipurpose Mobile Battery for Port of San Diego and/or Other Applications**	No	RFPs in 2020	Module 1: Two bidders passed initial screening. Module 2: Two bidders passed initial screening.	Module 1: Tesla, Inc. for Mobile Battery; Anser Advisory LLC for Engineering Services Module 2:Quanta Technology LLC	Both modules: selected highest ranked bidders in the respective RFPs.	N/A	N/A	No	N/A

Project status information for EPIC-1 and EPIC-2 was included in prior annual reports and is not included above, because the projects were completed in prior years.

Investment Program Period	Program Administrator	Project Name	Applicable Metrics	San Diego Gas & Electric Company 2021 EPIC Project Status Report
3rd Triennial (2020)	SDG&E	**PROJECT 3: Application of Advanced Metering Infrastructure (AMI) Data to Advanced Utility System Operations**	Ability to monitor, visualize, and analyze visualization information can help reduce number of outages, as well as their frequency and duration. The transmission fault location use case is particularly beneficial for this purpose. Public safety improvement and hazard exposure reduction can also be accomplished by advanced visualization tools, for example, in the AMI for operations use case, where the voltage swell and sag are visually monitored. This application is used for monitoring in emergency scenarios, such as Red Flag Warnings and earthquakes. Improved access to AMI data and awareness company-wide. For example, in the load curtailment visualization use case, the load curtailment is visually represented to help users visualize the curtailment locations and details as data on a map. This is expected to be beneficial in emergencies.	**Module 1** The SDG&E and NREL team completed execution of the pre-commercial demonstration, data gathering, and analysis of results. The project activities and results were incorporated into a comprehensive final project report written and finalized in the third and fourth quarters of 2021. Module 1 focused on using AMI data for a voltage sensor network. NREL assisted SDG&E in demonstrating the tools and strategies for using the AMI-based field measurements for distribution system monitoring and planning. **Module 2** In Module 2, a competitive procurement was carried out to select vendor tools for demonstration and evaluation. SDG&E teamed with these vendors to carry out the demonstration work. SDG&E internal and vendor methodologies were developed, and demonstrations were conducted throughout 2021. Final project reports were completed by each vendor and the internal SDG&E team. An integrated final project report was created that includes each of the methodologies demonstrated and a summary of the results.
3rd Triennial (2020)	SDG&E	**PROJECT 4: Safety Training Simulators with Augmented Visualization**	**Module 1** A key metric is shorter SAIDI minutes for outages because of quicker fault location identification. Another key metric is reduced usage of test closure to identify fault location, and the resulting longer asset life, and improved power quality. The ultimate key metric is the effectiveness of the training simulator in achieving improved operating practices that result in achieving the above metrics. There will be a task that tests the capture of learning by those taking the training. A quantitative basis for valuation of the above metrics will be used in the analysis phase of this project module. Additional benefits of commercial adoption may also be identified as the work progresses. **Module 2** A key metric that was used is the safety of the employees, in the context of back feed from customer generation (distributed energy resources). Another key metric was the expected reduction of outage times and injuries attributable to the training. The ultimate key metric will be the general effectiveness of the training simulator, compared to current practice.	**Module 1** After sufficiently scoping and describing the work tasks, SDGE issued an RFP in 2020 securing a contractor to work with SDGE internal staff. Contract executions occurred in late 2020 and early 2021. The bulk of the contracted work occurred in Q2 through Q4, with the final report being drafted, edited, and finalized by the internal and contractor team by the end of the year. The ultimate outcome of the project was a recommendation to pursue commercialization to provide long term benefits in terms of safety, reliability, and student learning outcomes. **Module 2** Module 2 was successfully completed, and the final report drafted, edited, and finalized, by year end. The ultimate outcome was a recommendation for commercialization of the software, to ensure long term improvements in student learning outcomes, as new operator trainees enter the program to become fulltime, fully qualified system operators.

Project status information for EPIC-1 and EPIC-2 was included in prior annual reports and is not included above, because the projects were completed in prior years.

Investment Program Period	Program Administrator	Project Name	Applicable Metrics	San Diego Gas & Electric Company 2021 EPIC Project Status Report
3rd Triennial (2020)	SDG&E	**PROJECT 5: Unmanned Aircraft Systems (UAS) with Advanced Image Processing for Electric Utility Inspection and Operations**	Example metrics are: •Use Case 1 – Examine the value proposition for having the ability to live stream video feed to any department during an emergency. •Use Case 2 – Determine the pros, cons, and value proposition for Beyond Line of Sight (BLOS) UAS applications. •Use Case 3 - Demonstration work is targeted at determining the value proposition for full integration of UAS night patrols in a PSPS event and being able to bring power back to a customer in a faster and less costly manner. •Use Case 4 – The metrics are to compare the cost of using a corona camera on a UAS versus traditional practice and confirm the value proposition for the former. •Use Case 5 -- The metric is the extent of increased situational awareness during emergency events and having a UAS that can stay airborne as long as it has power, without battery changes or charging needed. •Use Case 6 – Determine the value proposition for using this tool in any high vegetation areas or areas where manned aircrafts are not desired or allowed due to the low flight elevation.	The pre-commercial demonstrations of various use cases were completed and a final report was completed at the end of 2021. Given the successes of this EPIC project, it is recommended that additional work be done to further evaluate and expand use of these UAS technologies and use cases to identify others that can be used commercially in future utility system operations. The final project report is provided in this document's appendix and is posted to SDG&E's public website at www.sdge.com/epic.
3rd Triennial (2020)	SDG&E	**PROJECT 7: Demonstration of Multipurpose Mobile Battery for Port of San Diego and/or Other Applications**	The project metrics were tracked through milestones marked by completion of project plan tasks. Specific value metrics for the project were measured by comparative analysis, utilizing current base practices and historical data (i.e. customer load demand and profile, net energy metering, power quality metering, energy consumption algorithms and calculations, and emissions reporting.), collecting new data through application of the mobile battery system, comparing the data specific to each use case, and analyzing the benefits.	**Module 1** Competitive procurement for the Module 1 battery was conducted in early 2020, and a contract was awarded to provide an MBESS in March 2021. Initially, the Port of San Diego cruise ship terminal was selected as a location for battery demonstration, but it was later determined a variety of factors made deployment at this site unfeasible during the pre-commercial demonstration Instead, the battery was brought to Marine Group Boat Works (MGBW), a Port of San Diego tenant, and to SDG&E's Cameron Corners Microgrid (CCM) site in Campo, CA. At MGBW, use cases like load smoothing, peak shaving, and other tests were successfully performed, and results are laid out in the final report. At CCM, the mobile battery successfully islanded the customers downstream of the microgrid yard, which was augmented by using generators for a total duration of 23 hours. The demonstration work was completed in the 3rd and 4th quarter of 2021. **Module 2** Competitive procurement for the Module 2 battery system and engineering services was conducted and awarded in 2021. A single contractor was selected to supply both the battery and engineering services. After receiving the battery and conducting commissioning tests, the battery was rotated to two CRCs in areas that are highly susceptible to PSPS. It ran for 24 hours at each location to ensure the battery can provide power reliably and for a long period of time. The demonstration work was completed in the 4th quarter of 2021. All findings for each module were included in their respective comprehensive final reports. These final project reports are included in the appendix of this annual report and are posted on the SDG&E EPIC public website at www.sdge.com/epic. The ultimate outcome from this demonstration work is that it is recommended that SDG&E pursue commercial adoption of MBESS.

Project status information for EPIC-1 and EPIC-2 was included in prior annual reports and is not included above, because the projects were completed in prior years.

EPIC Final Report

Program	Electric Program Investment Charge (EPIC)
Administrator	San Diego Gas & Electric Company
Project Number	EPIC-3, Project 3, Module 1
Project Name	Application of Advanced Metering Infrastructure Data to Advanced Utility System Operations
Date	December 31, 2021

Attribution

This comprehensive final report documents the work done in Electric Program Investment Charge (EPIC) 3, Project 3, Module 1. The project team that contributed to the project definition, execution, and reporting included the following individuals:

San Diego Gas and Electric (SDG&E)

- Tom Bialek
- Jay Bick
- Frank Goodman
- Chippy Impreso
- Julian Jones
- Kyle Kewley
- Gina Lindsay
- William O'Brien
- Amin Salmani
- Subburaman Sankaran
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- Stacy Williams
- William Wood

National Renewable Energy Laboratory (NREL)

- Santosh Veda
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- Valerie Rose
- Murali Baggu
- Martha Symko-Davies
- Jiyu Wang
- Jing Wang
- Jun Hao
- Marcos Netto

Executive Summary

San Diego Gas & Electric (SDG&E) and National Renewable Energy Laboratory (NREL) collaborated on a project funded through the California Public Utility Commission's (CPUC) Electric Program Investment Charge (EPIC) and U.S. Department of Energy (DOE). The purpose of EPIC-3, Project 3 is to demonstrate capabilities for leveraging SDG&E's AMI system with its 1.4 million electric meter endpoints to provide actionable secondary voltage data and analysis to SDG&E staff and other prospective users. The project focus included two modules. Module 1 focused on using Advanced Metering Infrastructure (AMI) data for a voltage sensor network, while Module 2 focused on using AMI data to identify endpoint phasing and meter-to-transformer mapping. This report addresses Module 1 only. The comprehensive final report for Module 2 is provided in a separate document.

SDG&E is looking to leverage its existing (AMI) to provide a foundational, pervasive secondary voltage monitoring network and a phase identification system. Through this pre-commercial demonstration project, NREL assisted SDG&E in demonstrating the tools and strategies for using the AMI-based field measurements for distribution system monitoring and planning. Specifically, NREL configured the tools to estimate primary network voltages, identify planning network model discrepancies, and automate phase mapping and meter-to-transformer mapping using the AMI measurement data.

The AMI data-based grid operation is an alternative to conventional model-based approaches where non-validated equivalent circuit models are used for determining the operational strategies, such as controlling voltage regulation devices and smart inverters to achieve voltage regulation. Further, as the penetration of photovoltaic (PV) systems increases, SDG&E also desired to study the associated impacts on the distribution system and the effectiveness of the integration measures. The PV smart inverter study in this project examined the impacts of PV on the distribution circuit voltage profile and traditional mechanical voltage regulation equipment operations. The efficacy of various PV smart inverter settings was quantified using the SDG&E feeder models.

Key Findings

The following are the key findings of the pre-commercial demonstrations using NREL developed tools:

- The utility feeder models used in this project have inaccuracies due to incorrect phasing, line parameter issues, and approximations used in the load and PV profiles.
- The machine learning models of the service transformer secondaries can provide reasonable estimation of the primary voltages. However, training data is essential for building these machine learning models. The primary voltage estimates from the physics-based method can be used as the training data for building the machine learning models of the secondaries.
- Circuit characteristics, measurement data available, PV penetration levels, and quality of geographic information system (GIS) data impact the selection of phase identification algorithms. The phase identification algorithms that work well in one feeder may not show similar performance in a different feeder depending on the feeder characteristics.

The algorithms based on supervised learning showed higher accuracy levels compared to those based on unsupervised learning for phase identification. However, supervised learning requires training data. Accuracy levels of nearly 90% and 94% are obtained on the selected two feeders in this study using a supervised learning algorithm with 30% training data, where a feeder is defined as a three-phase set of conductors (power lines) emanating from a substation circuit breaker serving customers in a defined local distribution area.

- Existing high PV penetration levels in the selected SDG&E feeder create voltage issues both on the primary and secondary networks. Enabling PV smart inverter settings significantly reduced the voltage exceedances in the simulations. There are minor variations in the voltage improvement among different smart inverter settings, but generally the voltage profile is better when smart inverters are enabled compared to when they are disabled.
- The volt/var curve slope is a key parameter influencing the voltage improvement.

Recommendations

The use cases presented in this project demonstrate the accuracy, feasibility, and rationality of using AMI data for greatly improving the planning and operations activities in the near-term, especially for feeders with high levels of PV adoption. It is recommended that specific tools (Utility Planning Network Model Anomaly Detection Tool, AMI Meter-to-Transformer Mapping, and Phase Identification Using AMI Data) be applied by the SDG&E team for other feeders. The evaluation of data-driven controls using realistic emulation capabilities of the ADMS Test bed provides a feasible demonstration for real-time data-driven control of high-PV feeders for consideration and implementation in the medium-term. Such an approach could reduce the reliance on planning models and make the operations resilient to the ubiquitous problem of poor model quality.

SDG&E will need to identify a stakeholder group within the company to lead this commercial adoption process.

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List of Acronyms

Acronym	Acronym Description
ADMS	Advanced Distribution Monitoring System
AMI	Advanced Metering Infrastructure
ANSI	American National Standards Institute
CPUC	California Public Utilities Commission
CRADA	Cooperative Research and Development Agreement
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DOE	Department of Energy
EPIC	Electric Program Investment Charge
ESIF	Energy Systems Integration Facility
GIS	Geographic Information System
IAB	Industry Advisory Board
HPC	High Performance Computing
MAPE	Mean Absolute Percentage Error
NREL	National Renewable Energy Laboratory
PHIL	Power Hardware in the Loop
PLM	Peak Load Management
PU	Per Unit
QSTS	Quasi Static Time Series
SCADA	Supervisory Control and Data Acquisition
VE	Voltage Exceedance
VUI	Voltage Unbalance Index
VVO	Volt-var Optimization

1.0 Introduction

The purpose of EPIC-3, Project 3 is to demonstrate capabilities for leveraging SDG&E's AMI system with its 1.4 million electric meter endpoints to provide actionable secondary voltage data and analysis to SDG&E staff and other prospective users. The project focus included two modules. Module 1 focused on using Advanced Metering Infrastructure (AMI) data for a voltage sensor network, while Module 2 focused on using AMI data to identify endpoint phasing and meter-to-transformer mapping. This report addresses Module 1 only.

As the penetration of photovoltaic systems increases, the voltage on the service transformer secondary increases, and when coupled with power production from renewable generation sources, there is potential for voltage to exceed American National Standards Institute (ANSI) C84.1 Range A limits. SDG&E is looking to leverage its existing AMI infrastructure to provide a foundational, pervasive secondary voltage monitoring network and a phase identification system to address these and other issues associated with monitoring and managing their distribution system. Through this project, NREL assisted SDG&E in evaluating the challenges and mitigation strategies associated with high penetration PV-in the distribution circuits. The proposed approach is an alternative to a conventional model-based approach where equivalent circuit models are used for determining operational strategies. NREL leveraged its Energy Systems Integration Facility (ESIF) high performance computing (HPC) simulation and advanced distribution monitoring system (ADMS) test bed capabilities for pre-commercialization and evaluation of the approach and solutions envisioned by SDG&E.

2.0 Project Objectives

The primary objective of the proposed scope was pre-commercial demonstration and evaluation of NREL-developed algorithms and tools for leveraging secondary network voltage measurement data made available through the AMI. The algorithms, tailored for use in this project, use the AMI data provided by SDG&E, collected from selected customer smart meters on selected feeders for data-centric grid planning and operations. A feeder (also known as a circuit) is defined as a three-phase set of conductors (power lines) emanating from a substation circuit breaker serving customers in a defined local distribution area. In addition, some of the challenges of using a non-modeled control i.e., without relying on the network model for computing the control decisions, were identified. The lessons learned will be disseminated to the broader utility community and other stakeholders through this comprehensive final report filed with the CPUC and released on SDG&E's EPIC public website and through submission to peer-reviewed publications and workshops, either co-authored by SDG&E and NREL or with the approval of SDG&E. The project demonstrated the value of AMI data for performing the following:

- Identification of anomalies in planning models
- Identification of customer phasing information at the meter-level
- Demonstration of effectiveness of different smart inverter settings on customer voltages

3.0 Issues and Policies Addressed

This project module endeavored to understand the impact of high PV penetration in the SDG&E service territory and determine the effectiveness of technology solutions such as energy storage, smart inverters, flexible loads, and other solutions to mitigate issues. The proposed approach is an alternative to a conventional model-based approach where non-validated equivalent circuit models are used for determining operational strategies. The demonstration leveraged NREL's ESIF HPC simulation and PHIL capabilities to evaluate the approach and solutions envisioned by SDG&E.

The project team collaborated through a Cooperative Research and Development Agreement (CRADA) on pre-commercial demonstration of tools, models, and algorithms for leveraging the SDG&E AMI infrastructure and data for advanced grid monitoring and planning. Through this collaboration, the project team developed a framework for generating synthetic AMI data for different PV penetration scenarios; developed, demonstrated, and integrated a new technique for identifying discrepancies in primary network models; and developed methods for analyzing and visualizing AMI datasets for an SDG&E feeder. This framework is shown in Figure 1 below. The framework allows for the generation of multiple scenarios of interest by applying different load/PV characteristics to the validated planning model, and the application of data processing techniques that mimic the data processing in AMI meters to generate synthetic AMI data. The machine learning-based data analytics algorithms can be applied on this synthetic AMI data to study the performance of the algorithms in these planning scenarios that do not exist in the field today but may be anticipated in the future. The work performed in this demonstration project was an extension of this CRADA with specific focus on analyzing the impact of different PV penetration scenarios through AMI data, phase identification, and meter to transformer mapping.

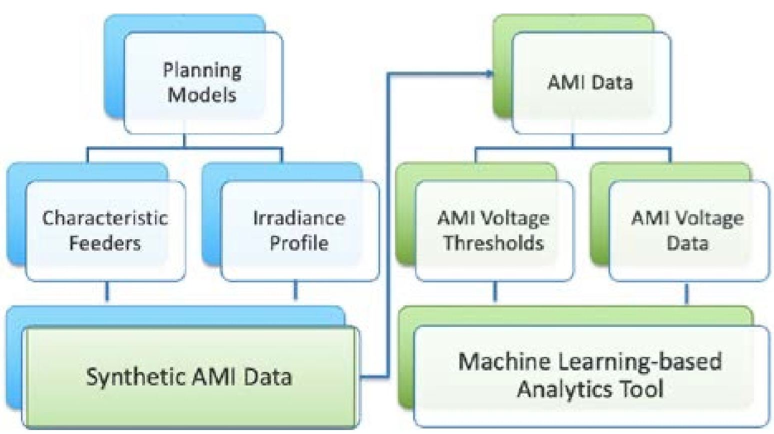

Figure 1. Framework for generating synthetic AMI data

4.0 Project Focus

The focus of this project module was to demonstrate advanced AMI data-based techniques for improving utility planning and operations. Some of the focus areas included identification of anomalies in the network planning model, demonstrating the impact of different PV inverter settings on customer voltage profiles as observed through AMI data, and demonstrating an advanced AMI data-based voltage control using a realistic emulation capability at NREL called the ADMS Test Bed.

5.0 Project Scope Summary

The scope of the work included using data from SDG&E's existing AMI infrastructure. AMI data from selected SDG&E feeders was used to identify the individual phases of the customer meter on the feeder and map the customer meters to the corresponding service transformers. These selected feeders are Feeders A and B. Feeder A has 325 connected transformers and 5,173 connected meters. It serves a relatively dense suburban neighborhood with a mix of overhead and underground wiring and a relatively even mix of line-line (L-L) and (L-N) phasing on the transformers. Feeder B has 649 connected transformers and 2,393 connected meters. It serves a spread-out suburban neighborhood with predominantly underground wiring and predominantly line to neutral (L-N) phasing on the transformers. The results from the analysis were validated through field verification conducted by SDG&E field personnel. The team evaluated the algorithms on the ADMS test bed located in the ESIF at NREL using realistic feeder parameters and distributed energy resources (DER). Further, NREL worked with SDG&E personnel to deploy the algorithms on SDG&E's analytics platform for further consideration for operationalization.

The primary objective of the project module was pre-commercial demonstration and evaluation of NREL-developed algorithms and tools for leveraging secondary network voltage measurement data made available through the AMI. The algorithms used the AMI data provided by SDG&E, collected from selected customer smart meters on selected feeders for data-centric grid planning and operations. In addition, some of the challenges of using a non-modeled control i.e., without relying on the network model for computing the control decisions, were identified. The lessons learned will be disseminated to the broader utility community through this comprehensive final report that will be filed with the CPUC and released on SDG&E's EPIC public website and through peer-reviewed publications and workshops with the consent of SDG&E. The project team embarked on the following use cases:

- PV Smart Inverter Study
- Utility Planning Network Model Anomaly Detection Tool
- Phase Identification Tool
- Meter to Transformer Mapping
- Data-Centric Grid Operations

PV Smart Inverter Study

High PV penetration levels in distribution feeders can cause operational challenges including voltage issues, reverse power flow, and protection issues. Standards recommend using PV smart inverters to support the distribution grid services, specifically voltage regulation. However, there are many smart inverter settings recommended by the standards and their performance on the SDG&E feeders has not been reported in literature. In this study, the impact of various smart inverter settings including California Rule 21 (CA 21) [6], Hawaii Rule 14 [7], IEEE 1547 [8] with no deadband, CA 21 with reactive power compensation at only high or low voltage range (referred to as "hockey stick" in this report), and volt-var-watt control on the selected SDG&E feeders was examined.

Utility Planning Network Model Anomaly Detection Tool

An automated tool was demonstrated that uses the AMI measurement data to identify the inaccuracies in the network model used for distribution planning. Numerous distribution network analysis, monitoring, and control applications; including volt/var optimization, state estimation, and distribution automation, require accurate distribution network models. The GIS maintained by utilities can be inaccurate because of a significant amount of missing data, restoration activities, and network reconfiguration. This can lead to network model inaccuracies. The utility planning network model anomaly detection tool used the AMI data to identify network model issues. It accomplished this by building the approximated secondary network models from the AMI data and using them to estimate the primary voltages. The estimated primary voltages were then compared with the primary voltages obtained from the simulations of the utility planning network model to identify model anomalies.

Phase Identification Tool

The phase identification tool performs automated phase mapping of the AMI meters based on AMI data. The GIS database maintained by the utility is known to have phase connectivity errors due to restoration activities, network reconfiguration, human error, and missing data. Traditionally, the phase connectivity database is periodically updated by field verification which is expensive and time-consuming. With the availability of AMI data, the phase connectivity can be identified through data analytics. The existing phase identification techniques work well in distribution feeders that have low or no PV generation; however, they fail to identify the phases accurately when considerable PV generation is present. The phase identification tool demonstrated in this project uses supervised learning to determine the phase connectivity accurately even when significant PV generation is present.

Meter-to-Transformer Mapping

Utilities generally have a meter-to-transformer connectivity mapping database. However, the records in this database do not always reflect the latest field conditions due to routine meter field changes and occasional human data entry errors. Accurate meter-to-transformer mapping information is needed for load balancing, service order work, and transformer load management. A solution that can check and correct the service transformer and meter mapping records is required to address this need. The goal of this use case was to demonstrate a proof-of-concept AMI meter-to-service transformer mapping solution that identified incorrect records based on AMI measurement data.

Data-centric Grid Operations

The integration of ADMS and AMI measurements offers a unique opportunity to further modernize grid control. In this use case, an AMI-based, data-driven, volt/var control algorithm, and its synergies with ADMS for distribution grid operations, were evaluated using SDG&E feeder and AMI data. The inputs of this algorithm were AMI power and voltage measurements. The algorithm controls the substation transformer load tap changer (LTC) tap position, capacitor bank switch positions, and PV inverter setpoints to ensure voltage regulation. This new paradigm for grid operations was demonstrated using NREL's ADMS Test Bed capability wherein the feeders and the controls were implemented and evaluated in a realistic utility environment.

6.0 Initial Benefits Analysis and Value Proposition

The initial benefit estimate and value proposition focused on improved distribution network reliability, reduced cost, increased safety, and enhanced environmental sustainability.

Improved Reliability

The utility planning network model anomaly detection tool provides distribution network operators greater visibility into their systems and helps them understand the voltage dynamics on the primary network. This can help in taking corrective actions in terms of updating device control settings or installing additional regulation devices to ensure voltages are maintained within the desirable limits and reliable network operation. As DER penetration levels increase, the traditional assumption that voltage drops network-wide is no longer valid. Virtual sensors on the primary network that provide voltage estimates are desirable to monitor voltage dynamics on the primary network. Further, identification of the inaccuracies in the utility planning network model is a key step in the correction process. The corrected models result in improved planning and operation decisions, leading to greater network reliability.

The phase identification tool further enhances reliability by maintaining the phase connectivity information in the model based ADMS and the Distributed Energy Resource Management System (DERMS). Phase identification will further support complex phase balancing. The PV smart inverter study quantified the impact of different smart inverter settings recommended in the standards on the network voltage profiles. These insights guide utilities to recommend and configure appropriate smart inverter settings for the PV systems within their service areas to ensure desired voltage levels across their networks.

Reduced Costs

The estimation of the primary voltages, based on the AMI data by the utility planning network model anomaly detection tool, removes the need for installing physical voltage sensors for planning purposes. Thus, it is more economical. Similarly, the phase identification tool determines the customer phase connectivity analytically based on the AMI data. Traditionally, the utilities undertake expensive field verification activities from time to time to keep their phase connectivity up to date. Alternatively, special equipment is used to detect customer phasing. When the AMI data is available, relying on the phase identification tool for the automatic phase mapping results in lower costs as it does not require additional equipment or field checks.

As the PV penetration levels increase, high voltage volatility is anticipated on the distribution networks. Traditionally, network upgrades or installation of advanced grid-edge devices are required for improving the network voltage profiles. As the grid standards now mandate PV smart inverters to participate in voltage regulation, configuring the appropriate smart inverter settings effectively supports the voltage regulation without having to resort to expensive traditional network upgrades. Further, the fast voltage regulation capability of the PV smart inverters reduces the wear and tear on the traditional mechanical voltage regulation devices. Thus, appropriate PV smart inverter settings can lead to lower investment and maintenance costs.

Increased Safety and/or Enhanced Environmental Sustainability

The phase identification tool promotes increased safety by reducing the need for personnel to travel and work in the field for the phase connectivity verification activities. This also results in reduced greenhouse gas (GHG) emissions from the vehicles used for this travel. The PV smart inverter study demonstrated that the PV smart inverters can help improve the voltage profile of the distribution networks and support grid integration of higher amounts of renewable energy sources. This promotes the environmental sustainability by accelerating the use of clean energy resources.

7.0 Use Cases

7.1 PV Smart Inverter Study

In recent years, the penetration of residential and commercial rooftop PV systems has been increasing rapidly [1]. The PV systems, however, can cause issues with the distribution system when penetration is high [2] [3]. The power outputs from PV systems peak at noon on a sunny day but the load consumption for residential customers at that time is typically low. These inconsistent profiles of PV output and load can cause overvoltage and reverse power flow problems [4].

To solve issues resulting from renewable energy generation, standards are now requiring utilization of PV smart inverters. Smart inverters can absorb or supply reactive power, or automatically curtail power output to maintain voltage levels [5]. Additionally, smart inverters have the ability to compensate for the voltage fluctuations in the grid via reactive power control even when the generation is not operating. There are many recommended smart inverter settings, and their performance on SDG&E feeders has not yet been fully studied. This demonstration simulated and studied the feeder operation with all distributed PV systems equipped with smart inverters. Different rules were tested including California Rule 21 (CA 21), Hawaii Rule 14, IEEE 1547 with no deadband, hockey stick, and volt-var-watt control. The performance of each rule was evaluated by using a set of metrics.

7.1.1 Configuration and Methodology

Load disaggregation was performed to extract the load and PV profiles from the AMI net load measurements. A custom function was created in Python to emulate different volt-var-watt functionalities and settings suggested in standards as such a function is not available as needed in OpenDSS. The OpenDSS is an electric power Distribution System Simulator (DSS) for supporting distributed resource integration and grid modernization efforts.

Load Disaggregation

The distribution feeder model used in this study, for the purpose of discussion, is Feeder A. The AMI data of this feeder was provided for the period between October 1, 2018, to January 15, 2019 (107 days). AMI load measurements from SDG&E included the net load consumption of each customer, therefore, a disaggregation was required to extract the PV profile and load profile for each load location. From the load definition in the feeder model and peak power generation of each PV system, the determination was made that the PV penetration for this feeder is around 70% relative to peak load. The irradiance profile of the feeder area during the selected period of 107 days was downloaded from the National Solar Radiation Database (NSRDB) [9]. By using the ratings of each PV system, the irradiance profile, and the net load profile of each load node, the PV profile and load profile at each load location were disaggregated. After the disaggregation, the scenario of 100% PV penetration was modeled with the load and PV profiles. This was the case used in the following simulations.

Volt-VAR-Watt Smart Inverter Function

In OpenDSS, the volt-var-watt smart inverter control function is not yet fully operational, therefore a Python function to implement the volt-var-watt control was created. The inputs of the function include inverter rated kVA, solar irradiance at current time step, and measured per-unit (PU) voltage at the previous time step. First, the volt-var and volt-watt curves were predefined. Then based on the voltage and volt-watt curve, the function determined the required real power output and the maximum available reactive power. After that, the maximum available reactive power, and volt-var curve, and the reactive power output was calculated based on the measured voltage. The outputs of this function were the real and reactive power outputs of the PV system. These outputs were used to update the PV system output in OpenDSS.

PV Smart Inverter Curves

The smart inverter curves for all cases are summarized in this section. Several smart inverter curves, both from the standards and the custom curves of interest were studied in this work. These curves are depicted in Figure 2.

- *California Rule 21 (CA 21):* The maximum and minimum percentage of available reactive power is +/-30%. This percentage is zero when the voltage is within 0.967-1.033 PU and reaches maximum/minimum when the voltage is below/over 0.92/1.07 PU
- *Hawaii Rule 14 (HI 14):* The maximum and minimum percentage of available reactive power is +/-44%. This percentage is zero when the voltage is within 0.97-1.03 PU and reaches maximum/minimum when the voltage is below/over 0.94/1.06 PU
- *IEEE 1547*: The maximum and minimum percentage of available reactive power is +/-44%. This percentage is zero when the voltage is within 0.98-1.02 PU and reaches maximum/minimum when the voltage is below/over 0.92/1.08 PU

- *<u>California Rule 21 without deadband:</u>* The maximum and minimum percentage of available reactive power is +/-30%. This percentage reaches maximum/minimum when the voltage is below/over 0.92/1.07 PU
- <u>Hockey stick curve without compensation in low voltage region:</u> The minimum percentage of available reactive power is -30%. This percentage is zero when the voltage is below 1.033 PU and reaches maximum when the voltage is above 1.07 PU
- <u>Hockey stick curve with deeper Q absorption:</u> The minimum percentage of available reactive power is -75%. This percentage is zero when the voltage is below 1.033 PU and reaches maximum when the voltage is above 1.07 PU
- *<u>Volt-VAR-Watt:</u>* The volt-var curve is the same as California Rule 21. For its volt-watt curve, the maximum available real power starts to decrease from 100% when the voltage is above 1.06 PU and reaches zero when the voltage is above 1.1 PU

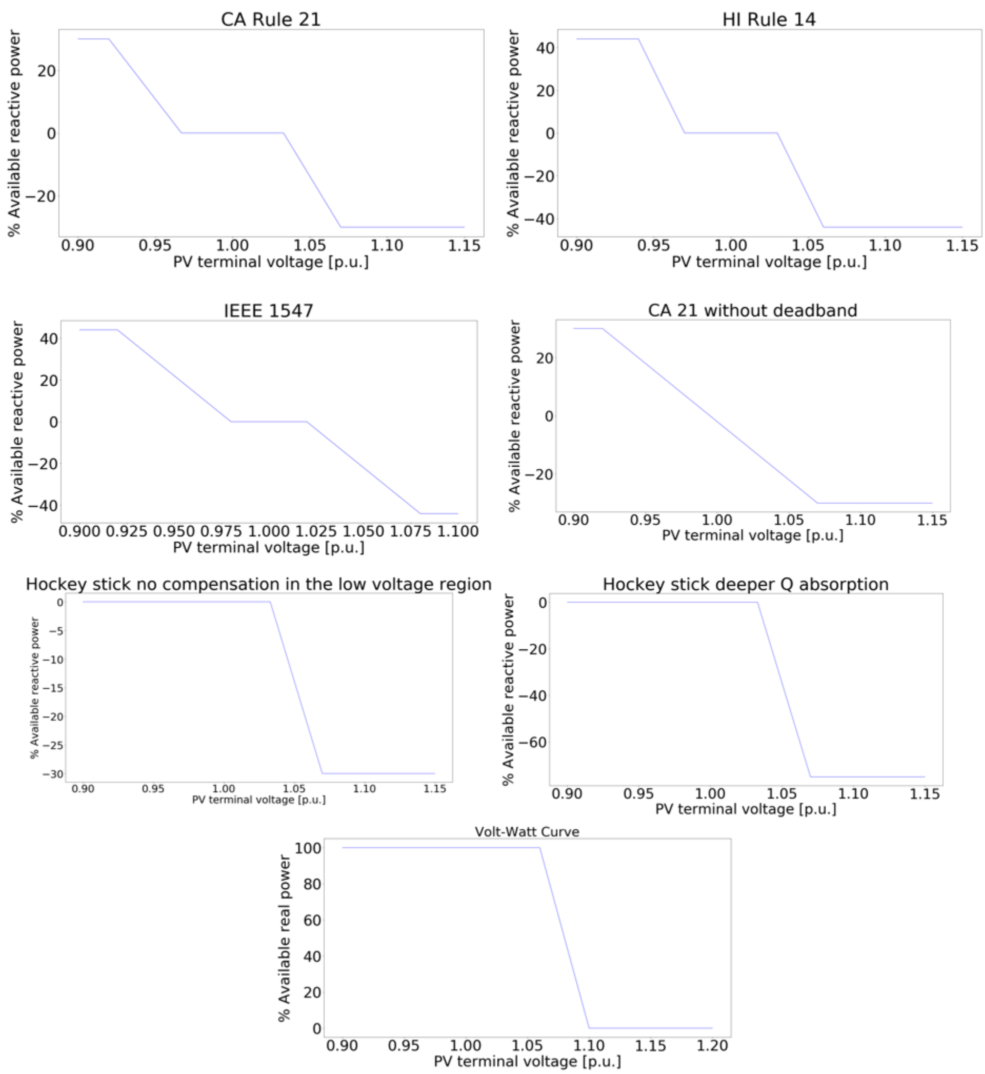

Figure 2. Volt-var and volt-watt curves for PV smart inverter

Metrics

The performance of each smart inverter function was evaluated by using multiple metrics: number of capacitor changes, number of LTC operations, average voltage, voltage fluctuation index, voltage unbalance index, and number of voltage exceedances nodes. Voltage fluctuations are described as repetitive or random variations of the voltage envelope due to sudden changes in the real and reactive power drawn by the load.

Let the T stand for the total time steps in the simulation and N stand for the total number of nodes in the feeder, the average voltage is calculated by:

$$V^{mean} = \frac{1}{N} \times (\frac{1}{T} \sum_{i=1}^{N} \sum_{t=1}^{T} V^i(t))$$

The voltage fluctuation index (VFI) measures how the nodal voltage is changing between time steps, i.e., voltage fluctuations across the circuit. It is calculated by:

$$VFI = \frac{1}{N} \times (\frac{1}{T} \sum_{i=1}^{N} \sum_{t=1}^{T} \left| V^i(t+1) - V^i(t) \right|)$$

The voltage unbalance index (VUI) measures the unbalance level of nodal phase voltages across the circuit. It is calculated by:

$$VUI = \frac{1}{N} \times (\frac{1}{T} \sum_{i=1}^{N} \sum_{t=1}^{T} V_{imb}^i(t))$$

where $V_{imb}^i(t)$ is calculated by using the maximum deviation from average voltage over the average voltage.

The voltage exceedance is defined as voltage out of range 0.94-1.06. The exceedance node is defined as a node with more than 12 hours exceedance in the three-month period.

7.1.2 Results and Discussion

The PV and load profiles were interpolated to five-minute resolution and the simulation was run using the data from October 2018 to January 2019 (107 days, 30,816 data points in total). There were 1,560 PV systems in the model in total, all with ratings between 5-10 kVA. For the baseline, the power outputs of PV systems were determined by the irradiance and inverter rating. For the case with smart inverter function enabled, the power outputs of these PV systems follow the corresponding curves. The voltage plots in this section are presented for one selected day i.e., October 1, 2018. The metrics were computed for the three-month period and summarized in Table 1 and 2.

California Rule 21

The voltage profiles for the selected day are shown in Figure 3. Note that the bus voltages are reduced during the day due to the LTC at the feeder head lowering the tap position to regulate the voltage rise due to PV.

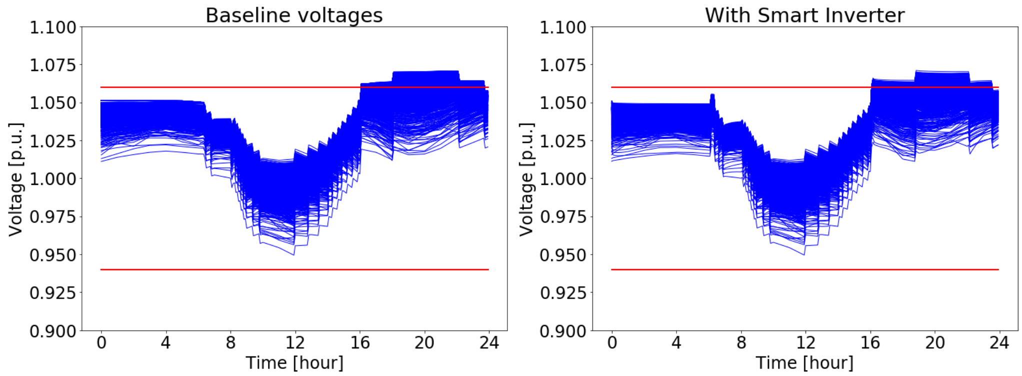

Figure 3. Daily voltage profile with/without CA 21 smart inverter

Hawaii Rule 14

The voltage profiles for the selected day are shown in Figure 4.

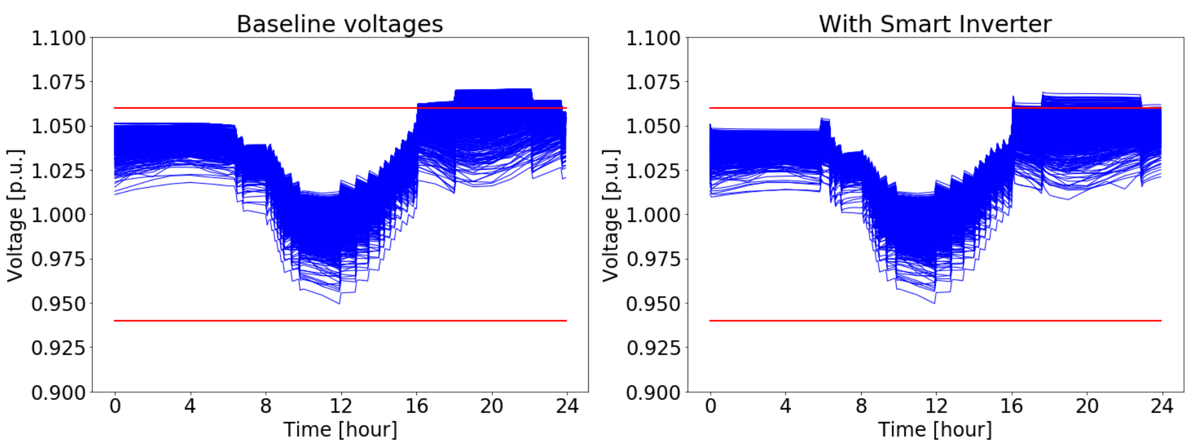

Figure 4. Daily voltage profile with/without HI 21 smart inverter

IEEE 1547

The voltage profiles for the selected day are shown in Figure 5.

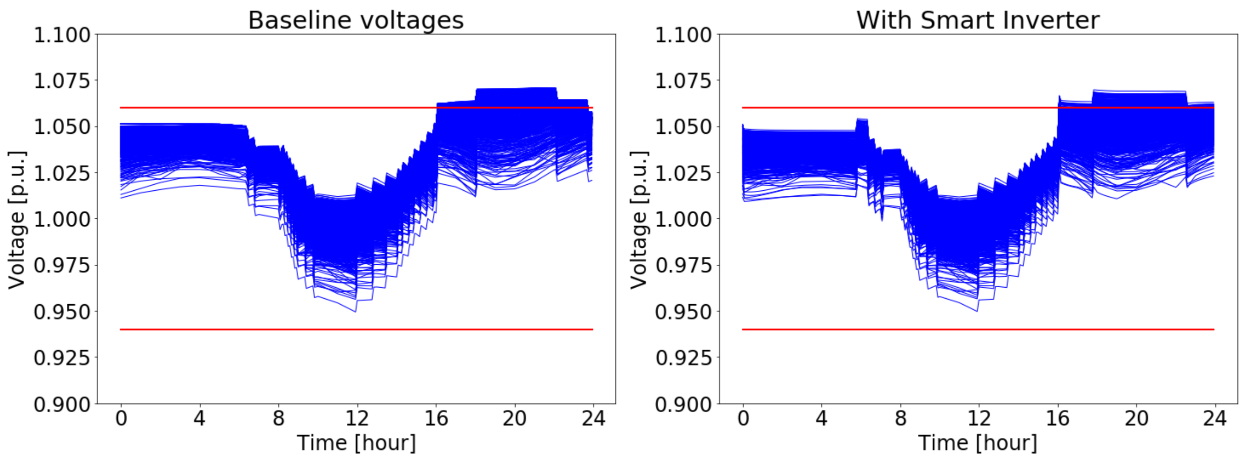

Figure 5. Daily voltage profile with/without IEEE 1547 smart inverter

California Rule 21 without Deadband

The voltage profile for the selected days is shown in Figure 6.

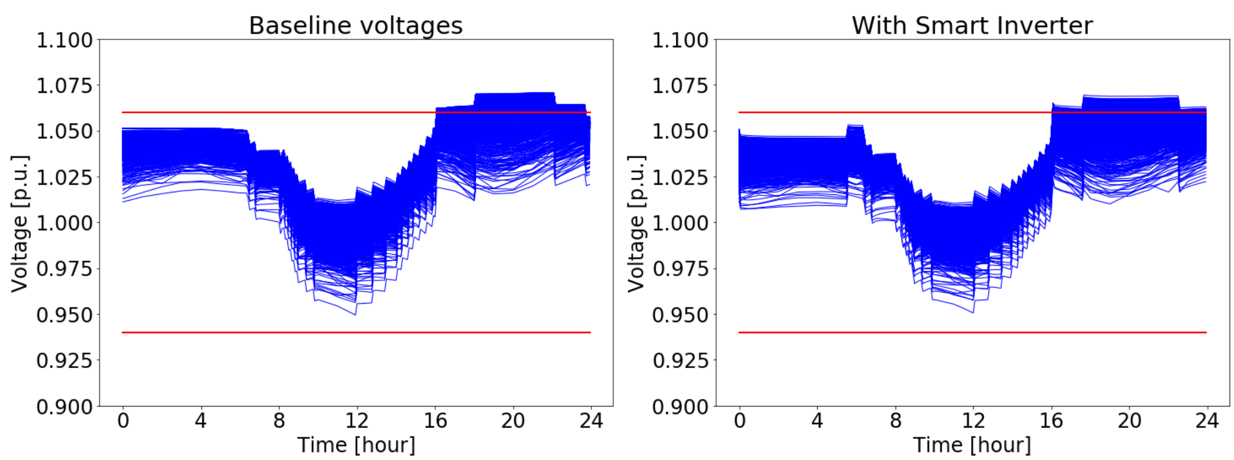

Figure 6. Daily voltage profile with/without CA 21 without deadband smart inverter

Hockey Stick Without any Compensation in the Low Voltage Region

The voltage profiles for the selected day are shown in Figure 7.

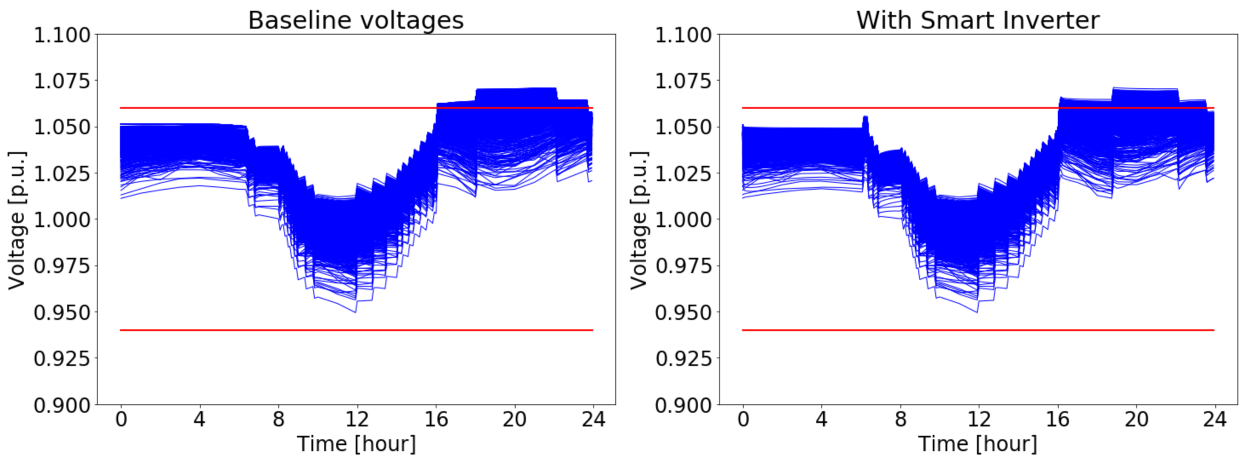

Figure 7. Daily voltage profile with/without hockey stick without compensation smart inverter

Hockey Stick with Deeper Reactive Power Absorption

The voltage profiles for the selected day are shown in Figure 8.

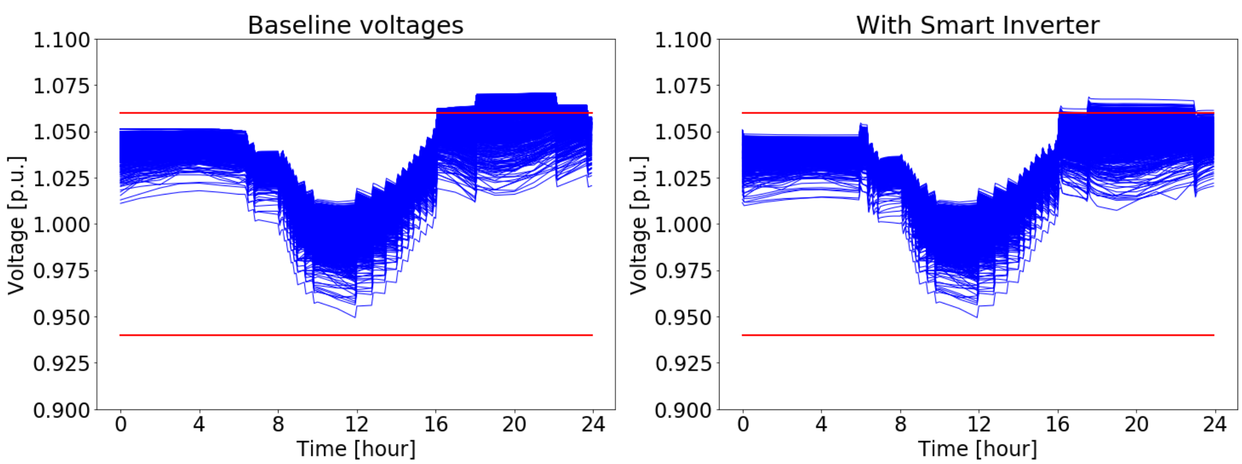

Figure 8. Daily voltage profile with/without hockey stick with deeper Q absorption smart inverter

Volt-Var-Watt Mode

The voltage profiles for one example day are shown in Figure 9.

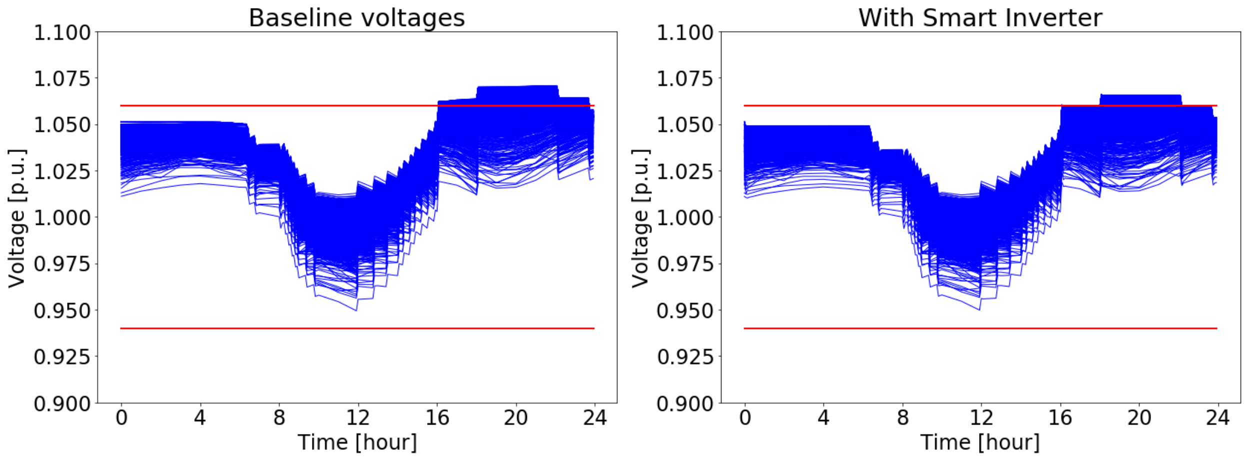

Figure 9. Daily voltage profile with/without volt-var-watt smart inverter

Summary for Three-Month Simulation

The summary of the three-month simulation for each smart inverter function is provided in Table 1 and Table 2.

Table 1. Summary of Feeder Operations

	Capacitor bank status changes	LTC tap changes	Average Voltage (V)	V fluctuation index score	V unbalance index score
Baseline	562	1291	249.93	9.67	9.90
CA 21	646	1335	249.20	9.68	9.86
HI 14	538	1471	248.60	9.67	9.82
IEEE 1547	580	1478	248.66	9.66	9.81
No Deadband	606	1394	248.41	9.67	9.77
HS-no compensation	646	1335	249.20	9.68	9.86
HS-deeper Q	624	1506	248.60	9.62	9.83
Volt-Var-Watt	158	784	250.27	9.61	9.81

Table 2. Summary of Voltage Exceedances

	Secondary		Primary	
	Voltage exceedances hours per node	Number of voltage exceedances nodes	Voltage exceedance-hours per node	Number of voltage exceedance nodes
Baseline	23.52	752	42.83	481
CA 21	0.55	16	0.61	0
HI 14	0.21	9	0.76	12
IEEE 1547	0.47	28	0.96	14
No Deadband	1.05	37	2.84	42
HS-no compensation	0.55	16	0.61	0
HS-deeper Q	0.09	3	0.91	12
Volt-Var-Watt	4.45	110	2.95	53

The results show the implementation of smart inverter settings improves the feeder voltage profile by reducing the voltage exceedances. Based on the results from the demonstration, the Rule 21 curve showed superior results in terms of the number of voltage regulation device actions and eliminating the primary voltage exceedances. The Rule 14 curve showed superior results in terms of eliminating the secondary voltage exceedances. The voltage exceedances for the volt-var-watt function are higher than the others, but it has the lowest number of voltage regulation device actions. The numbers of voltage regulation device changes are similar for all other smart inverter functions, and the average voltages are all near 249 V. Based on different purposes of controlling the feeder, the corresponding smart inverter functions can be selected by using the results from this demonstration. For example, if the utility wants to minimize the action times of the voltage regulation devices, Rule 21 can be set for the smart inverters on this feeder.

7.2 Utility Planning Network Model Anomaly Detection Tool

Numerous distribution network analysis, monitoring, and control applications, including volt/VAR control, state estimation, and distribution automation, require accurate distribution network models. The GIS maintained by utilities can be inaccurate because of a significant amount of missing data, restoration activities, and network reconfiguration. The voltage transfer software tool uses AMI data recorded on the distribution secondary network, static primary network connectivity data derived from the utility planning model, and voltage data from the time-series simulations of the utility planning model to identify the model anomalies. It accomplishes this by building the approximated secondary network models from AMI measurements and using them to estimate the primary voltages. The estimated voltages are then compared with primary voltages obtained from utility planning network model simulations to identify the mismatches. A list of primary buses having high mismatches is saved along with other mismatch statistics.

The software tool uses AMI data recorded on the secondary distribution network, static primary network connectivity data derived from utility planning model, and voltage data from time-series simulations of the planning model to identify the model anomalies as shown in Figure 10.

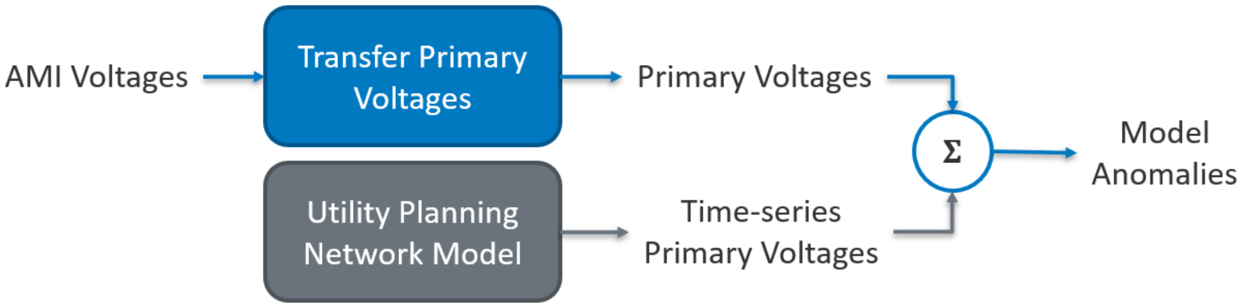

Figure 10. Illustration of utility planning network model anomaly detection tool

7.2.1 Configuration and Methodology

The software tool uses the combination of a physics-based method and a machine learning method to estimate the primary bus voltages from the AMI voltage measurements on the distribution secondary network.

Physics-based Method

In the physics-based primary voltage estimation method, the voltage magnitudes on the primary side of the distribution service transformers were estimated using only two smart meters per secondary network. The smart meters were strategically placed on the closest and farthest load (in the electrical sense) from the transformer, in the electrical sense. This method relies exclusively on smart meter data, and therefore it is fully data driven.

The physics-based primary voltage estimation method has two stages:

First Stage – Linear Regression: The first stage performed a linear regression on the latest data window available at the control center. A data window of 288 points was used, which is equivalent to a day for five-minute sampling resolution. The first stage was executed only once.

The equivalent circuit shown in Figure 11 was used for each service transformer. In this circuit, r_p and r_s denote the losses in the primary and the secondary winding of the service transformer, respectively. The variables, v_p' and v_s' denote the voltage magnitudes at the primary and the secondary of an ideal transformer, respectively and n_t is the transformer's turns ratio. The variables, v_1 and p_1 denote the voltage magnitude and the active power measured at the closest load from the service transformer while v_2 and p_2 denote the voltage magnitude and the active power measured at the farthest load from the transformer. The variables r_1 and r_2 account for cable impedance; and v_u and p_u are unknown. A constrained linear least-squares minimization problem was solved to estimate the resistance r_2 and the equivalent resistance between the first meter and the primary bus.

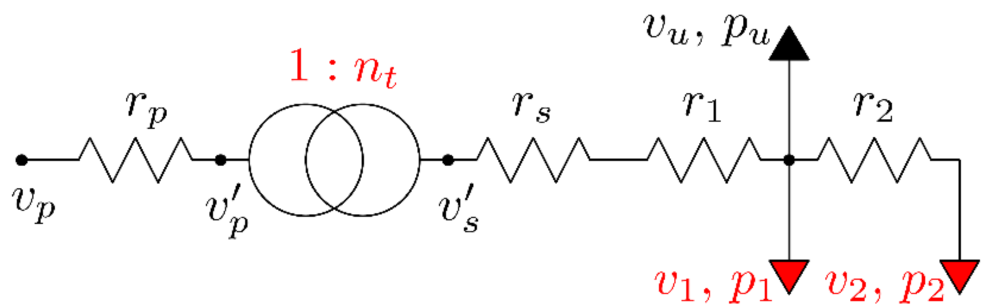

Figure 11. Equivalent circuit used for each secondary in physics-based voltage estimation method

Second Stage – Kalman Filtering: The second stage used a Kalman filter to update the primary voltage magnitude estimates continuously, based on new data points. The processing steps in both stages are discussed in [20].

Machine Learning Method

Machine learning approaches typically require a training data set that contains the features to be estimated. In this application, the inputs included AMI measured power and voltages of two customers under each service transformer and the total power consumption of all customers under the service transformer. The output is the transformer primary-side voltage. Therefore, the transformer primary voltage data must be included in the training data set in addition to the other specified feature data. However, because no primary-side measurements were available for this feeder, except the RTU voltage, time-series voltage data recorded from the simulations in OpenDSS were used to form the required training data set in the algorithm development stage. The quasi-static time-series (QSTS) simulation of Feeder A was performed in OpenDSS for the period between October 1, 2018, to January 15, 2019 (107 days) to obtain primary-side voltages. In the QSTS simulation, time resolution was set to hourly to follow AMI load time resolution. The load profile of each secondary-side measured load was set to be the AMI measured total power under that transformer. The simulated primary-side synthetic voltages from the QSTS simulation and the actual measured secondary-side voltages at the two AMI measured loads were used to train the machine learning model. The machine learning method for this application is discussed in [21].

After validating the performance of the machine learning-based algorithm using simulation data, it was applied to actual AMI measurement data recorded in the field. In this stage, the machine learning models were trained using the primary voltages estimated by the physics-based method instead of the simulation data.

Combined Method

Both the physics-based and the machine learning-based methods have limitations in estimating the primary-side voltages when applied individually. The physics-based method can use the available AMI data to conduct the estimation, but the accuracy is lower than desired. The machine learning-based method can have a higher estimation accuracy, but requires measurements of service transformer primary voltages, which was not included in the dataset provided. A combined method was developed to leverage the advantages of both these methods. In the combined method, primary voltages were estimated by the physics-based method for a given time duration, a primary voltage correction was applied, and corrected primary voltages were used to train a machine learning model. The trained machine learning models can be used to estimate primary voltages for any time duration.

Voltage drop across a service transformer typically varies from two to 13 V. The average voltage drop between the two AMI meters in all the secondaries of SDG&E Feeder A is 0.58 V. This implies that the voltage drop on a service transformer would be four to 20 times of the voltage drop between the AMI meters in the corresponding secondary. Accordingly, a correction factor was applied to the primary-side voltages estimated by the physics-based method before using them as training data for the machine learning models.

7.2.2 Results and Discussion

Physics-based Method

Five service transformer locations as shown in Figure 12 were selected to perform the validation of the physics-based method. The corresponding secondaries were modeled in detail with the realistic topology and load data. Each secondary model comprises a few loads including the two loads for which the AMI load consumption data was available. The load profiles of the two loads were set to be the same as AMI load consumption data for those two loads. The aggregated power consumption data at the service transformer level (minus the sum of the two loads) were distributed evenly across the rest of the loads of that secondary. The primary voltages of the selected secondaries were estimated using the physics-based method. The estimation mismatch results are summarized in Table 3. It can be observed that the estimation mismatches are all around 4%, which is larger than expected. The physics-based method usually will overestimate the primary voltages. Therefore, a machine-learning based method and a combined method are developed to improve the estimation accuracy.

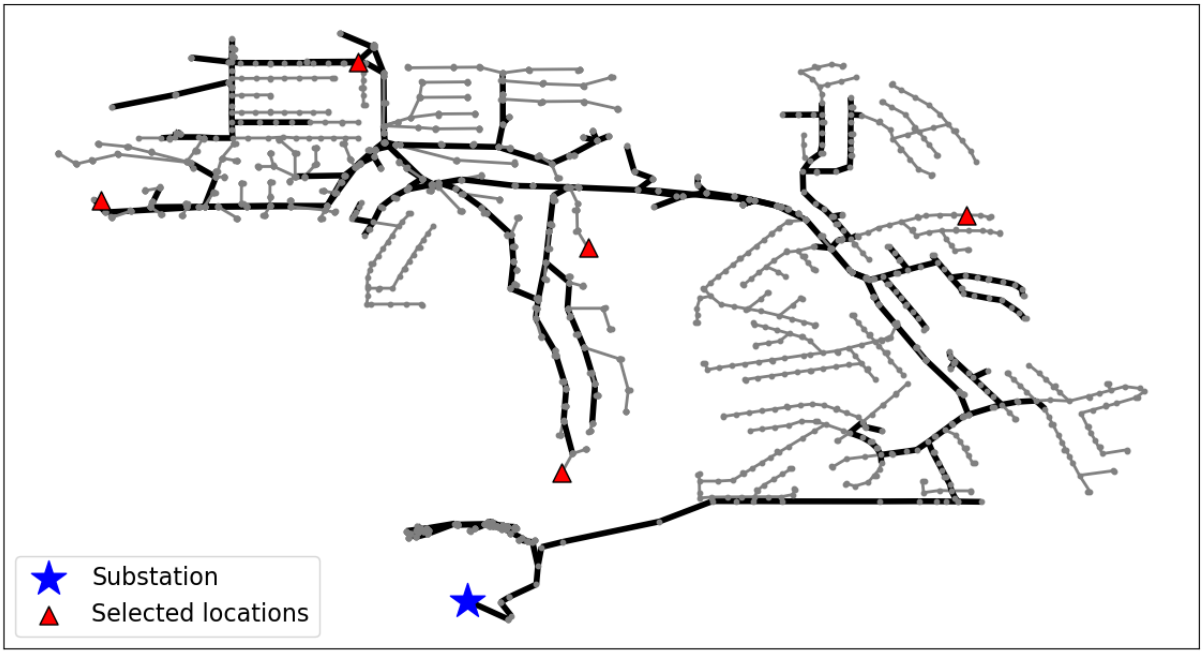

Figure 12. Five selected locations for the validation of physics-based method.

Table 3. Physics-based method validation results

	Estimation Mismatch
Secondary 1	3.74%
Secondary 2	4.06%
Secondary 3	3.53%
Secondary 4	4.28%
Secondary 5	3.84%

Machine Learning Method

Multiple machine learning algorithms: Random Forest, Adaptive Boosting, and Gradient Boosting [10] [12] were tested to find the relationship between the primary-side voltages and the AMI measurements under each service transformer. The data from each service transformer (341 in total) were trained separately to account for their unique characteristics, i.e., separate models were constructed for each service transformer. The input of each model was the hourly load measurement from two AMI meters under that service transformer, the average hourly AMI voltage measurement, and the total load of that service transformer. The output of the model was the voltage on the primary side of the service transformer.

The data from the first month were selected to compare the estimation accuracy of different algorithms. K-fold cross validation was used to validate the machine learning models, and the validation was repeated 30 times. In each test, 80% of the monthly data was randomly drawn from the data set to train the model, and the remaining 20% was used for testing. The mean absolute percentage error (MAPE) and maximum absolute percentage error between the synthetic primary voltage and estimated primary voltage was used to evaluate the performance of each machine learning method. The performance comparison is shown in Table 4.

Table 4. Performance of Different Methods

	Machine Learning Method		
	Random Forest	**Adaptive Boost**	**Gradient Boost**
MAPE	0.12%	0.75%	0.48%
Maximum	0.46%	1.08%	0.95%

The results summarized in Table 4 show that the Random Forest model performs better than the other two models in the selected performance criteria; therefore, it was selected to estimate the primary-side voltages in this study. Another advantage of using the Random Forest algorithm (as Random Forest is an ensemble learning method that integrates multiple decision trees) is that it will combine these decision trees and use average, or voting, schemes to calculate the results. Therefore, any outliers in the AMI measurements can be handled with this algorithm. Further, an exhaustive search was conducted to determine the model parameters (number of decision trees and maximum depth). These two parameters are varied from one to 500 and one to 30, respectively, to test the estimation performance. Considering both estimation accuracy and training time, the number of decision trees were selected to be 80 and the maximum depth to be 10. The time to build the machine learning model for each service transformer was around five seconds, and the total time for building the models for all service transformers was 30 minutes. As the process of training the model is usually developed for the distribution system planning studies, it meets the run-time requirement.

The performance of the machine learning-based approach was validated by the synthetic primary-side voltages generated from the QSTS simulation of the feeder model in OpenDSS. A secondary model was built for each service transformer in OpenDSS. Each secondary model included the two loads with voltage measurements and a load without voltage measurement. The load profiles of each secondary measured load were set to be one AMI measured power for one meter under that transformer. The load profile of the unmeasured load was set to be the AMI measured total power at that service transformer minus the two measured loads. The primary-side and secondary-side voltages at the two AMI measured loads recorded from the QSTS simulation were used to train the machine learning model. The data from the first 1,000 hours were used as a training data set to train the model for each service transformer, and the next 1,568-hour data were used to test the performance of each machine learning model.

The MAPEs for the estimation of all service transformer primary-side voltages are shown in Figure 13. All of them are less than 0.07%. Although the largest estimation error is around 0.65%, the number of such occurrences is very small. For most estimations, the error is less than 0.02%. Overall, the MAPE for all predictions in the feeder is 0.012%, and the MAPE for the service transformer with maximum error is 0.056%. Comparing with the 4% error from the physics-based method, the estimation accuracy improved a lot, however, this method requires some primary voltage data to train the machine learning model for each node. The comparison between estimated and actual voltages (synthetic voltage, in this case) for one example service transformer is shown in the two subplots of Figure 14. The first subplot shows the voltage comparison, and the second subplot shows the estimation absolute percentage error at each time step. Generally, the shape of the estimated voltages follows the actual voltages. The mismatch between the estimated and actual voltages is within 0.2%, which is very small. The model was also tested when using the first 2,000-hour data as the training dataset and tested with the remaining 568-hour data. The performance is similar to the previous case, which means the over-fitting problem does not exist for the model.

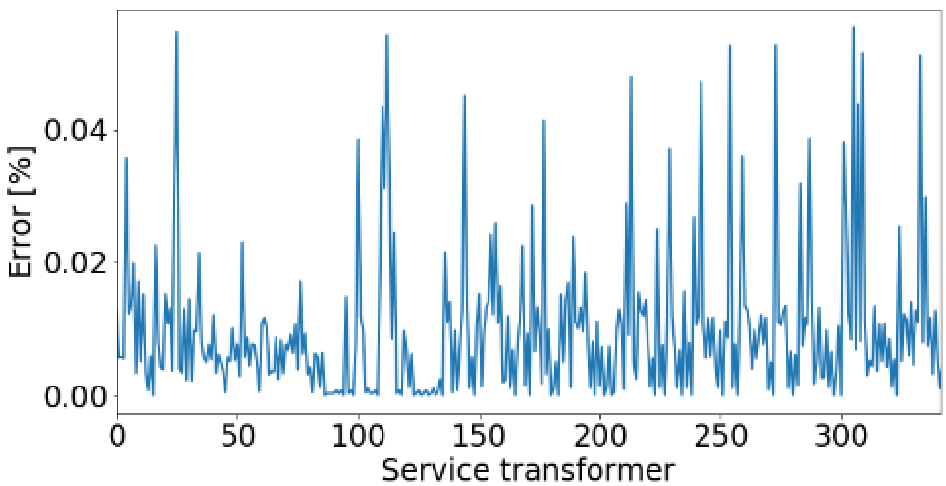

Figure 13. MAPE for the voltage estimation of each service transformer

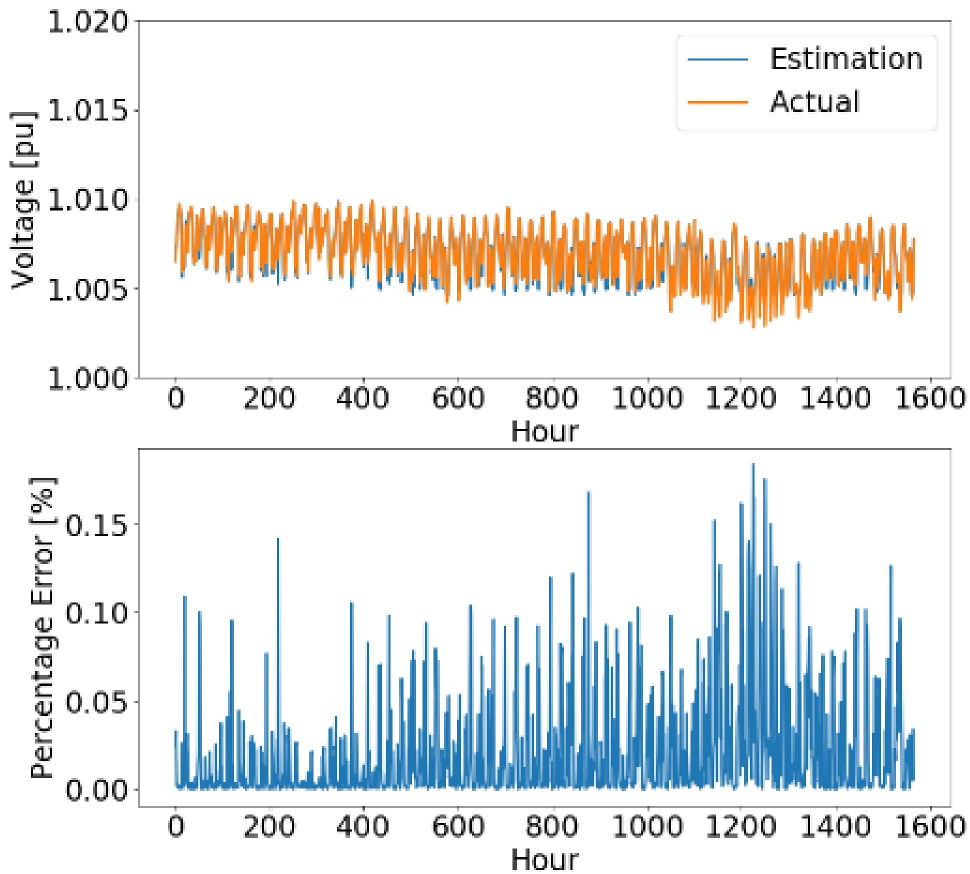

Figure 14. Comparison between estimated and synthetic voltages for one example service transformer

Combined Method

The performance of the combined method was validated by the synthetic primary-side voltages generated from the QSTS simulation of the OpenDSS model, since the primary-side voltages were not recorded in the field. The QSTS simulation was performed and the primary-side and secondary-side voltages at the two AMI measured loads for the five selected secondaries were recorded. These measurements from the secondary were used as AMI data to validate the combined methods. The estimation results are summarized in Table 5. From the results it can be observed that the estimation error decreased from 4% to 1% in the 2,000-hour testing period. Most of the time the errors are within 1%. If some other information is available, for example, some secondary topologies or the reactive power measurement, we can integrate them in the existing method to improve the estimation accuracy. This combined method was developed as a tool to estimate the primary voltages by using secondary AIM measurements.

Table 5. Combined method validation results

	Estimation Mismatch	
	Physics-based	**Combined**
Secondary 1	3.74%	0.90%
Secondary 2	4.06%	0.59%
Secondary 3	3.53%	0.43%
Secondary 4	4.28%	0.79%
Secondary 5	3.84%	1.40%

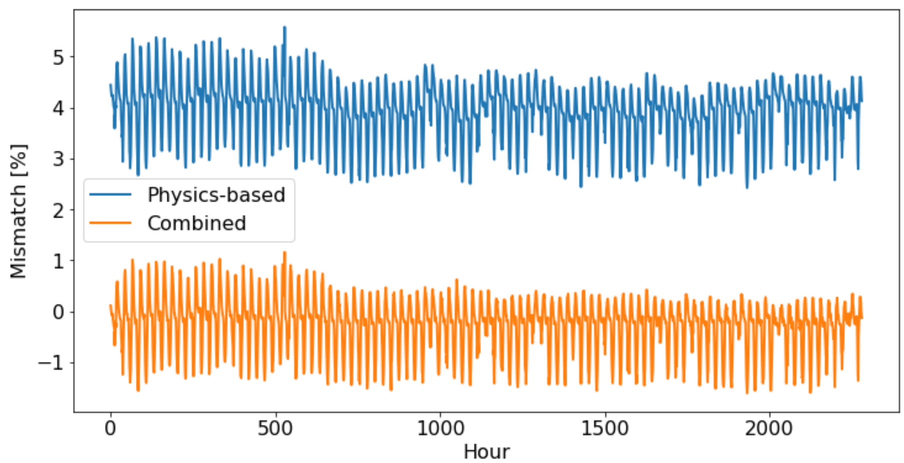

Figure 15. Estimation mismatch from one example secondary model

Identifying Planning Model Anomalies

The combined method was used to identify the anomalies in the distribution network planning model of Feeder A first. For this, the primary voltages estimated by the combined method for a selected duration were compared with those obtained from the time-series simulation of the distribution network planning model for the same duration. The peak load and minimum load days in December 2018 and January 2019 (four days) were selected for this process. The average estimation mismatches for all primary buses are shown in Figure 16 and the histogram of all estimation mismatches is shown in Figure 17. The geographic plot is shown in Figure 18.

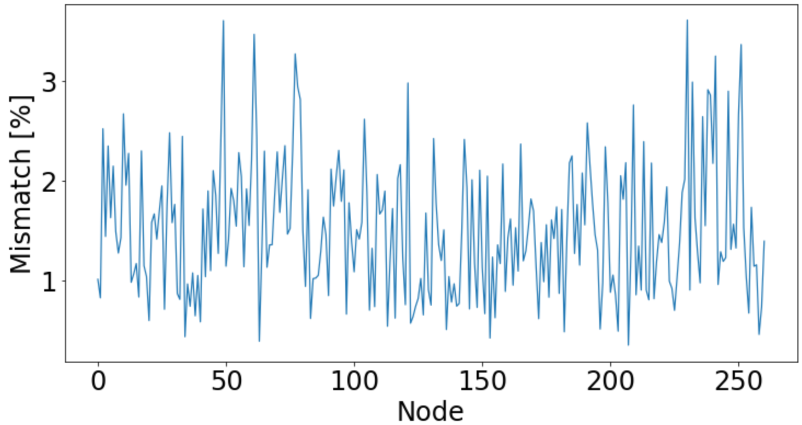

Figure 16. Estimation mismatch for all primary buses on Feeder A

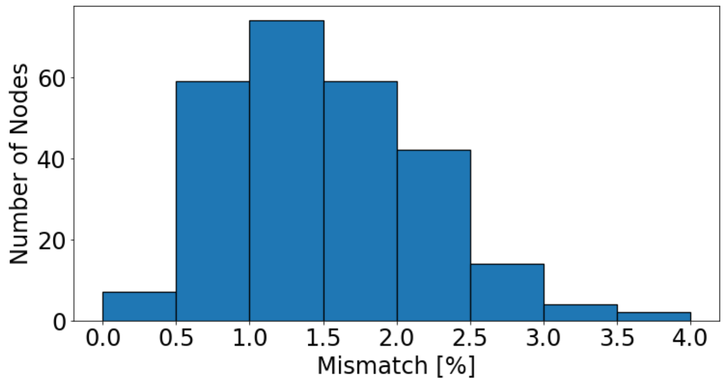

Figure 17. Histogram of all estimation mismatches in Feeder A

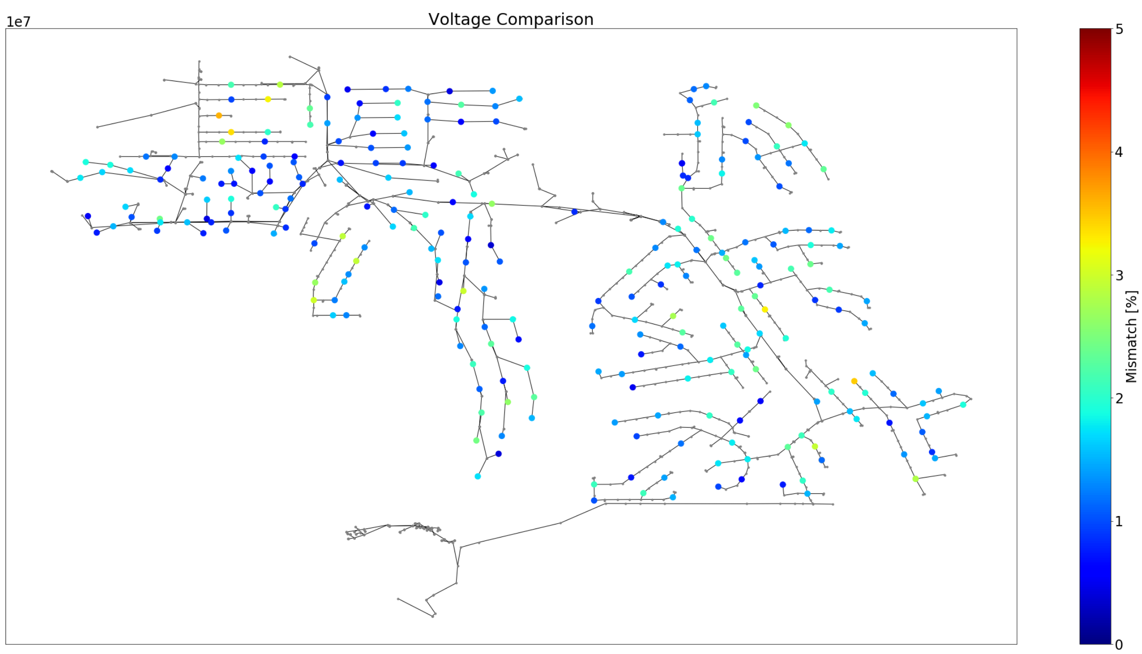

Figure 18. Geographic plot with the mismatch distribution on Feeder A

The combined method was also used to identify the anomalies in the distribution network planning model of Feeder B first. For this, the primary voltages estimated by the combined method for a selected duration were compared with those obtained from the time-series simulation of the distribution network planning model for the same duration. The peak load and minimum load days in August and September 2019 (four days) were selected for this process. The average estimation mismatches for all primary buses are shown in Figure 19 and the histogram of all estimation mismatches is shown in Figure 20. The geographic plot is shown in Figure 21.

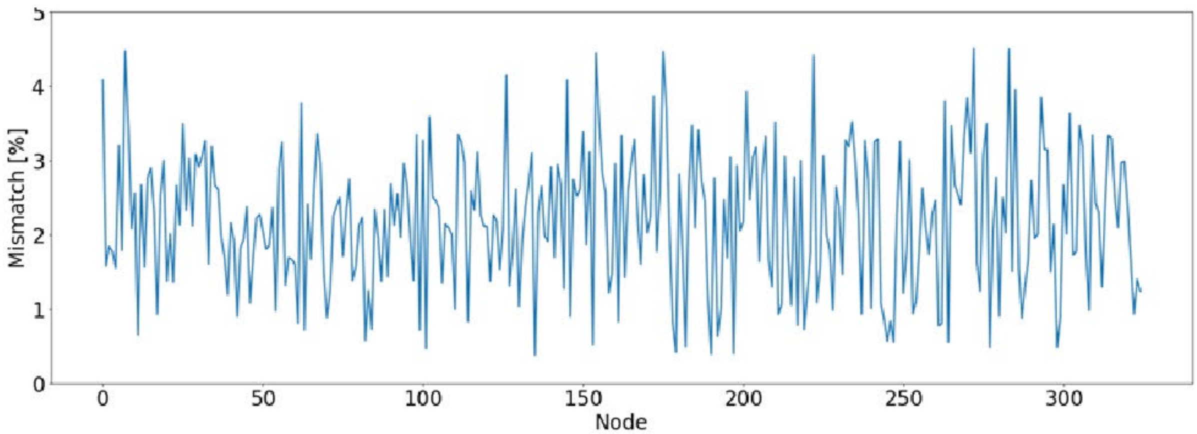

Figure 19. Estimation mismatch for all nodes on Feeder B

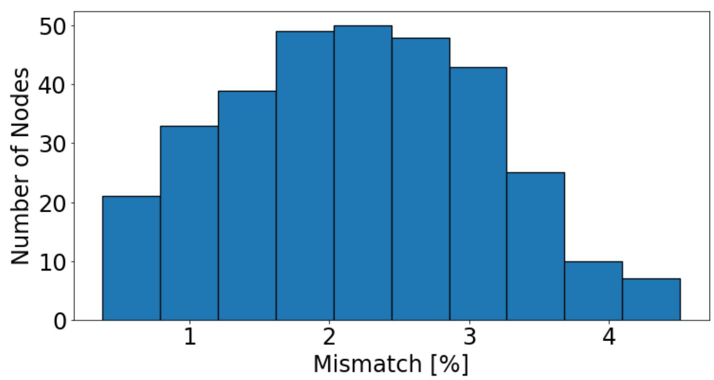

Figure 20. Histogram for all estimation mismatches for Feeder B

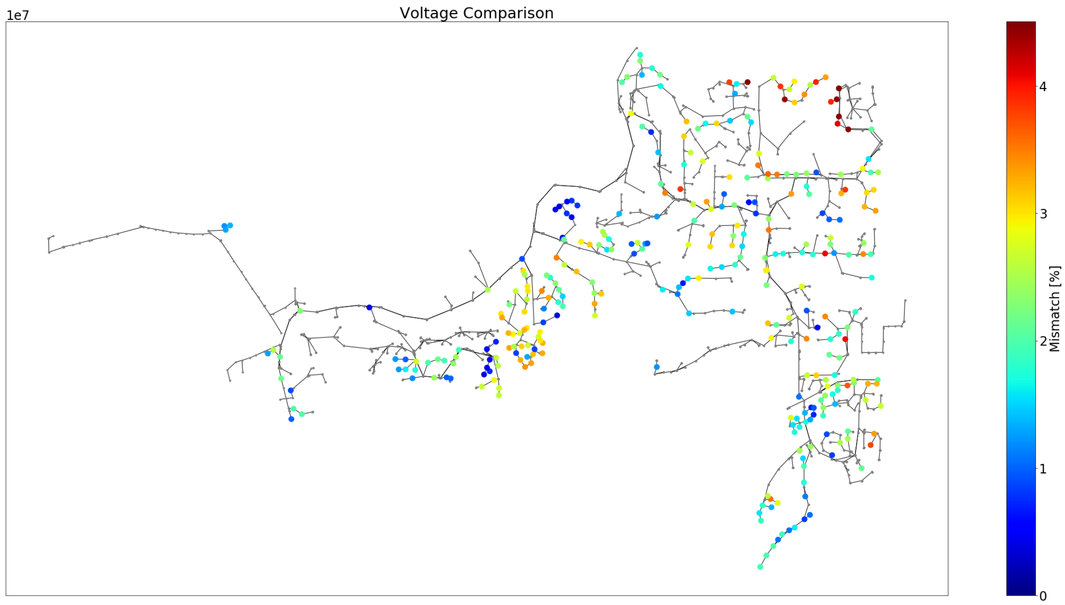

Figure 21. Geographic plot with the mismatch distribution on Feeder B

7.2.3 Challenges

One of the key challenges was the lack of measurement data. While the existing methods in the literature assume that every load in the secondary circuit is monitored by a smart meter, this study assumes that only two loads in the secondary circuit are monitored by smart meters. Lack of measurement data on the primary caused difficulties in the validation process. If the relevant network data, such as line and service transformer impedance parameters were available, that information could have been incorporated into the methods to achieve better accuracy levels.

7.3 AMI Meter-to-Transformer Mapping

With emerging technologies and distributed energy resources, the nature of power distribution systems has changed dramatically. Utility power engineers need more measurement data at the distribution level to monitor and keep the system stable. The AMI enables collection of a tremendous amount of data at the distribution level and can be used to design, test, and implement sophisticated distribution planning and control strategies. Real-time data recorded by AMI meters, along with the information recorded and provided by the GIS, improve the observability of distribution power systems.

7.3.1 Configuration and Methodology

The methodology for meter-to-transformer mapping solely uses the voltage data recorded by the AMI. There is no requirement for the length of the data. Additionally, the methodology accommodates missing data, which can be observed frequently in the voltage dataset.

The main idea is that the voltage measurements from the AMI meters connected to the same service transformer secondary should be highly correlated and have a high correlation coefficient. Therefore, the key is to find a threshold to identify the potential incorrect records. If the correlation coefficient is lower than the threshold, that means records are incorrect. The AMI meter to service transformer mapping procedure consists of the following steps:

1) Calculate correlation coefficient between meters connected to the same service transformer for the records in the existing database.
2) Rank the calculated correlation coefficients and pick a threshold.
3) Loop through all the correlation coefficients and select the AMI records whose correlation coefficients are lower than the threshold.
4) Calculate the correlation coefficients with the rest of the dataset and choose the service transformer with the highest score.
5) Perform Step 4 for each meter in the selected set of records in Step 3. If the score is higher than the threshold, then correct the record to the new service transformer and meter pair, otherwise keep the record the same.

For instance, consider that the correlation coefficient of AMI1 and AMI2 are lower than threshold τ in Figure 22, and they are connected to the service Transformer 1 in the original record. Then the algorithm will check the rest of the dataset to find a transformer with the highest correlation coefficient for both AMI1 and AMI2. If the score is higher than τ , then the algorithm will update the records. In this case, the mapping of AMI1 is changed to associate with Transformer 2 after running the algorithm.

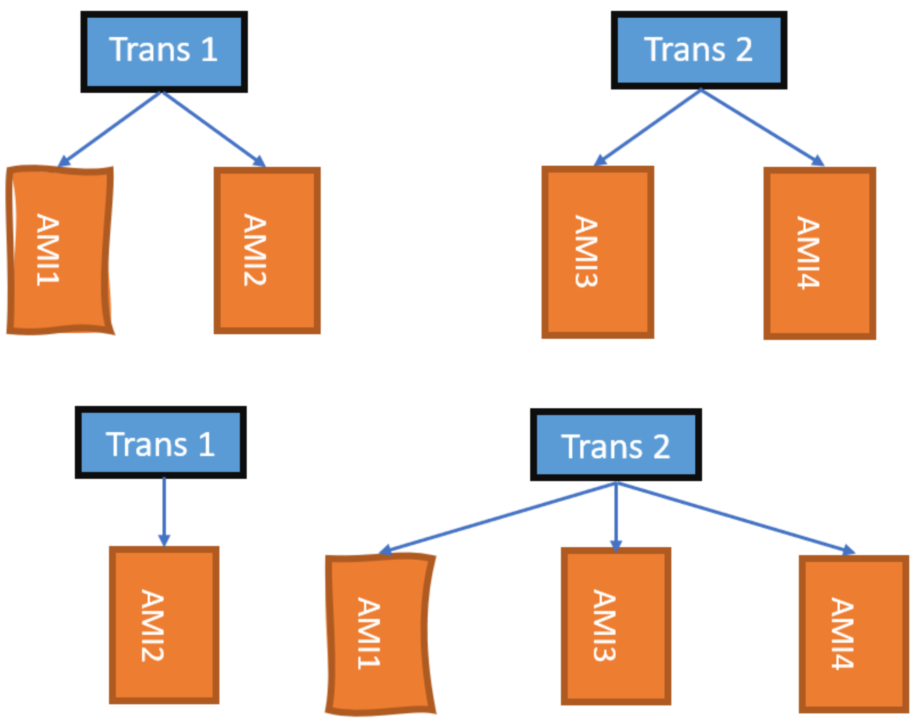

Figure 22. Illustration of the AMI meter to service transformer mapping algorithm

7.3.2 Results and Discussion

Recall and precision are used to evaluate the performance of the proposed methodology. Recall evaluates the overall accuracy of the algorithm, and precision evaluates the accuracy of the correction. The equations below show the definition of recall and precision in mathematical formulas. In our case, the true positive is the right correction, the false positive is the wrong correction, and the false negative means the records remain the same as before.

$$R(recall) = \frac{TP(True\ Positive)}{TP + FN(False\ Negative)}$$

$$P(precision) = \frac{TP(True\ Positive)}{TP + FP(False\ Positive)}$$

Three correlation coefficients namely Pearson [13], Kendall's rank [14], and Spearman's rank [15] are used in this work. These are defined as follows:

The Pearson correlation coefficient is a measure of linear correlation between two sets of data. It is the ratio between the covariance of two variables and the product of their standard deviations. The Kendall rank correlation coefficient is a statistic used to measure the ordinal association between measured quantities. It is a measure of rank correlation and the similarity of the orderings of the data when ranked by each of the quantities. Spearman's rank correlation coefficient is a nonparametric measure of rank correlation. It assesses how well the relationship between two variables can be described using a monotonic function.

Tables 6, 7, and 8 below, show the results of the methodology with three different correlation coefficient calculation methods.

Table 9 indicates that the Spearman correlation coefficient has the highest score in both recall and precision, and therefore fits the methodology best. All methods detect 97% of the incorrect records.

Table 9 summarizes the overall comparison results. The category, "# of swap" means the total number of incorrect records which are randomly created to test the methodology.

Table 6. Pearson correlation coefficient

Test	# of Swap	Detection	Correction	Right Correction
1	10	10	7	5
2	15	15	8	8
3	20	20	11	10
4	25	24	15	12
5	30	28	22	16
Summary	100	97%	63%	51%

Table 7. Spearman correlation coefficient

Test	# of Swap	Detection	Correction	Right Correction
1	10	10	7	5
2	15	15	10	9
3	20	20	12	10
4	25	24	15	13
5	30	28	23	17
Summary	100	97%	67%	54%

Table 8. Kendall correlation coefficient

Test	# of Swap	Detection	Correction	Right Correction
1	10	10	7	5
2	15	15	11	10
3	20	20	12	10
4	25	24	16	13
5	30	28	23	18
Summary	100	97%	69%	56%

Table 9. Method comparison

Method	Recall	Precision
Pearson	63%	80.95%
Kendall	67%	80.60%
Spearman	69%	81.16%

7.3.3 Challenges

In this exploratory task, our proposed algorithm detects almost all the incorrect records, achieves 81.16% of precision, and 69% of recall with the least information. However, there is 30% of the detection that cannot be assigned with correct service transformers. This part needs to be addressed and will further improve the overall performance.

7.4 Phase Identification using AMI Data

An accurate phase connectivity database is needed for the utility distribution networks for efficient grid operations [16]. This requires periodic updates by field verification to keep the phase connectivity database accurate, which is an expensive and time-consuming process. A faster and less expensive method of estimating the phase connectivity is necessary.

The widespread deployment of AMI presents opportunities to develop applications for grid planning and operations using measurement data. The AMI data can be used for identifying the phase connectivity of each AMI meter. This process is referred to as phase identification. Existing phase identification techniques that estimate phase connectivity work well in distribution feeders that have low or no PV generation; however, they fail to identify the phases accurately when considerable PV generation is present [17]. Further, some existing phase identification approaches can perform phase identification for phase-to-neutral or phase-to-phase connection only. They cannot be applied to the distribution feeders having both phase-to-neutral and phase-to-phase connections. In this demonstration, a phase identification algorithm was used that can be applied to distribution feeders having a mix of phase-to-neutral and phase-to-phase AMI meter connections. The algorithm used supervised machine learning to detect the phase connectivity accurately even in the presence of high PV penetration. The phase identification performance was validated on two feeders. The first feeder has a mix of phase-to-neutral and phase-to-phase AMI meter connectivity and nearly 70% PV level relative to the peak load. The second feeder has predominantly phase-to-neutral AMI meter connectivity, with very few service transformers having phase-to-phase connectivity. This feeder also has approximately 24% PV penetration relative to the peak load.

7.4.1 Configuration and Methodology

The key assumption in this study is that voltage profiles from AMI meters pertaining to each phase connectivity are highly correlated with each other. Thus, the voltage magnitude time series of the AMI meters that are on the same phase tend to exhibit similar variations in the voltage measurements which are different from the meters on the other phases.

Phase Identification using Supervised Learning

Phase identification was performed using the random forest classifier [18] [19]. The random forest classifier is a supervised machine learning model. In the phase identification process, first the voltage magnitude time series from each meter in the AMI dataset was obtained for a selected duration of time. Next, a preset percentage of meters were selected for each phase connectivity as a training dataset for the supervised machine learning algorithm. The phase connectivity of these meters must be accurate since this is part of the training process for the machine learning algorithm. Then a random forest classifier was constructed, which is a function that predicts the phase connectivity of each meter in the training dataset based on the voltage magnitude time series data. Finally, the trained random forest classifier was used to identify the phase connectivity of the rest of the meters in the AMI dataset based on their voltage magnitude time series.

The phase identification algorithm steps are given below:

1) *Data preprocessing:* Load the AMI dataset with the voltage magnitude time series data and perform data standardization. A small number of meters with consistently reported bad data or empty data were removed from the AMI dataset in this step.
2) *Training the random forest classifier:* Select 30% of the AMI meters for each phase connectivity for training the random forest classifier. The phase connectivity of these AMI meters, obtained

through field validation or some other means, was supplied to the random forest classifier in this step.

3) *Phase identification:* Input the voltage magnitude time series data of the rest of the meters to the random forest classifier model trained in Step 2 to identify the phase connectivity of the rest of the meters in the AMI dataset.

Data Requirements

The phase identification algorithm in this demonstration used the voltage magnitude time series data of the AMI meters and the validated phase connectivity information for 30% of the meters in the AMI dataset for training. The AMI dataset had average, maximum, and minimum voltages for each meter at five-minute intervals. The five-minute average voltage magnitude data was used for phase identification. The inputs and output of this algorithm are summarized below:

Inputs:

- Average voltage magnitude time series data (preferably three months or more) for each AMI meter at five-minute resolution
- Accurate phase connectivity information for 30% of the AMI meters for each type of phase connectivity

Output:

- A table with AMI meter ID and associated phase connectivity for all the AMI meters

7.4.2 Results and Discussion

The phase identification was performed on two of SDG&E's feeders, namely Feeder A and Feeder B. Two AMI datasets are used for Feeder A. The first dataset has the AMI data of the three-month period between October 1, 2018 to December 31, 2018 (2018 dataset) and the second dataset has the AMI data for the entire 2019-year period. For Feeder B, the AMI data for the entire year of 2019 was used. The phase identification results of the two feeders are documented in this section.

Distribution Feeder Details

The first feeder used for the phase identification is Feeder A. This is a 12-kV feeder with a peak load of 10.3 MW. The topology of the feeder is shown in Figure 23. The substation transformer is equipped with a load tap changer. Three capacitor banks are available on the feeder for reactive power support. The feeder serves more than 5,000 customers using 341 service transformers. Solar generation of approximately 70% relative to the peak load is present in this feeder.

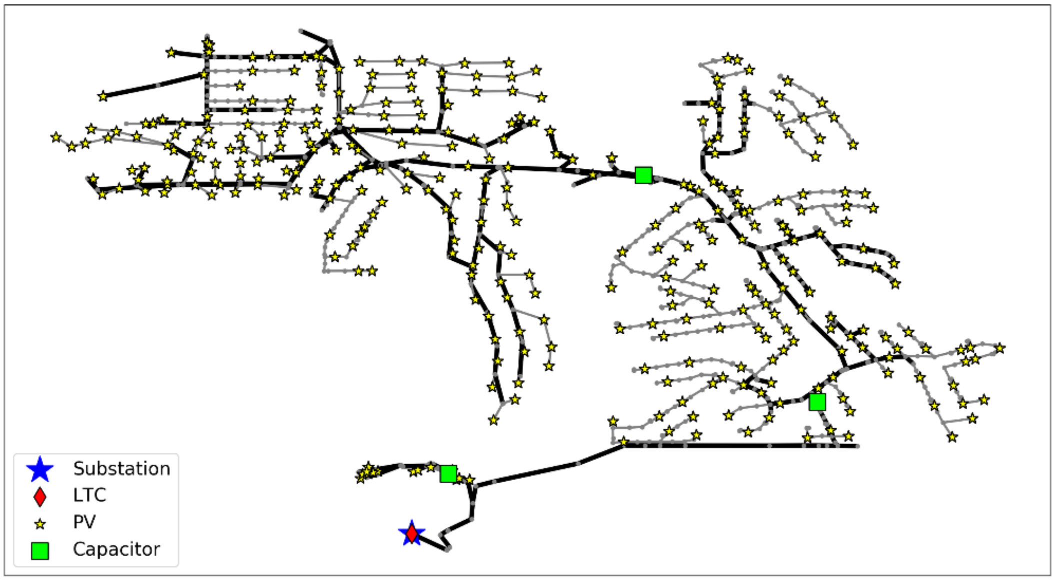

Figure 23. Topology of Feeder A

The second feeder used for the phase identification is Feeder B. This is also a 12-kV feeder with a peak load of 13.29 MW. The topology of the feeder is shown in Figure 24. The substation transformer is equipped with a load tap changer. Two capacitor banks are available on the feeder for reactive power support and there are no line voltage regulators. This feeder has 657 service transformers. Solar generation of 3.14 MW is present in this feeder which is approximately 24% relative to the peak load.

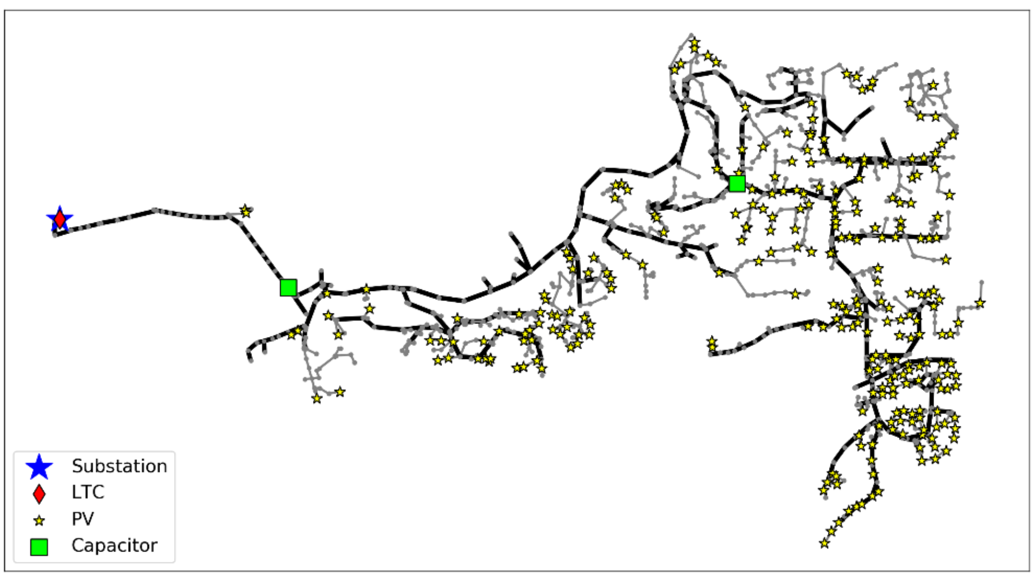

Figure 24. Topology of Feeder B

Phase Identification in Feeder A using 2018 AMI Dataset

Phase identification was performed on Feeder A first using the 2018 AMI dataset. This dataset has the average voltage magnitude time series data for 561 AMI meters for the three-month period between

October 1, 2018 to December 31, 2018. The AMI data for two meters per service transformer were available in this dataset. Additionally, the field validated phasing information was also available for all the meters. Based on this information, the distribution of the phasing for the AMI meters is shown in Figure 25.

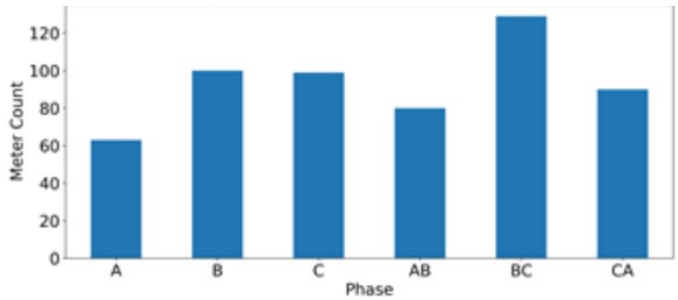

Figure 25. AMI meter phasing distribution in 2018 AMI dataset of Feeder A

The phase identification results are shown in Figure 26. The field validated phasing information is considered as the ground truth. For each type of phase connectivity, the number of meters the algorithm identified as pertaining to that connectivity is shown against the ground truth. The results show the phase identification algorithm can identify all the types of phase connectivity accurately.

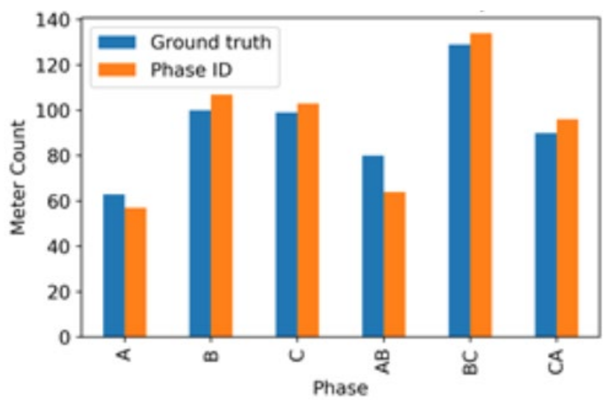

Figure 26. Phase identification results of Feeder A using 2018 AMI dataset

The detailed breakdown of the AMI meter counts in each of the training, testing, and full datasets of phase identification are shown in Table 10. For each type of phase connectivity, 30% of the meters are selected randomly along with their ground truth phase connectivity for the training dataset. The full dataset includes both the training and testing datasets together. With the phase connectivity identified accurately for 335 out of 391 meters in the testing set alone, the phase identification accuracy is 85.7% on the testing set. The phase identification accuracy on the training and full datasets are 100% and 90%, respectively.

Table 10. Summary of phase identification results of Feeder A using 2018 AMI dataset

Dataset		Phase Connectivity						Total	Accuracy
		A	B	C	AB	BC	CA		
Full	Ground truth	63	100	99	80	129	90	561	90%
	Phase identification	53	96	96	60	122	78	505	
Testing	Ground truth	43	67	70	57	92	62	391	85.7%
	Phase identification	33	63	67	37	85	50	335	
Training	Ground truth	20	33	29	23	37	28	170	100%
	Phase identification	20	33	29	23	37	28	170	

The geographic distribution of the AMI meters for which the phase connectivity identified by the algorithm matched the ground truth is shown in Figure 27. The meters are distributed all over the feeder; thus, the algorithm can detect the correct phase connectivity in all the feeder neighborhoods.

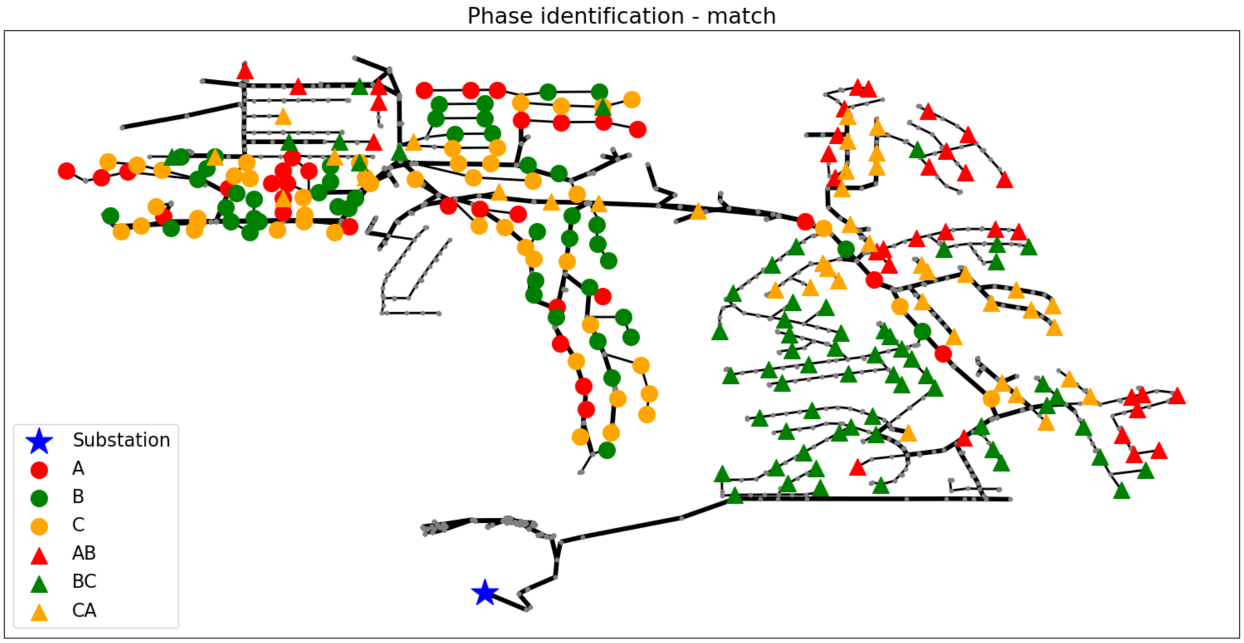

Figure 27. Locations of AMI meters for which the phase connectivity is identified correctly

The locations of the AMI meters where the identified phase connectivity does not match the ground truth are shown in Figure 28. The correct phase connectivity according to the ground truth is shown in this figure at these locations. The mismatches are generally not clustered or constrained to any specific feeder neighborhoods.

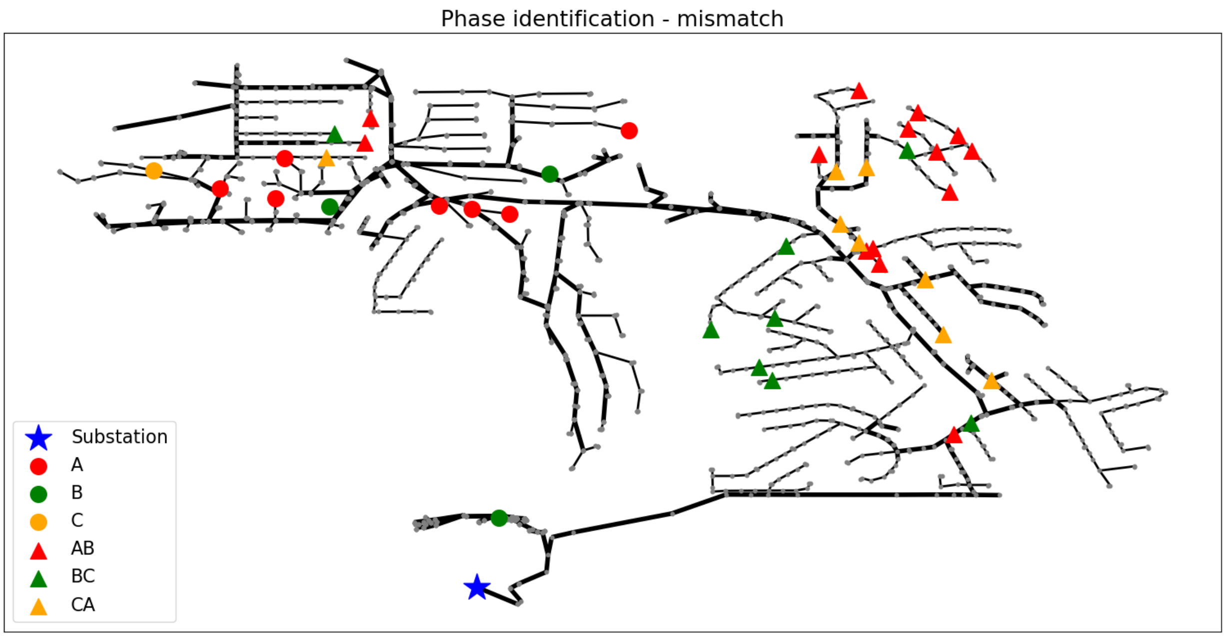

Figure 28. Locations of AMI meters for which the phase connectivity is identified incorrectly

Phase Identification in Feeder A using 2019 AMI Dataset

The phase identification was also performed on Feeder A using the 2019 AMI dataset. This dataset has the average voltage magnitude time series data for 568 AMI meters for the full 2019-year period. The AMI data for two meters per service transformer were available in this dataset in addition to the field validated phasing information. The phase identification results are shown in Figure 29. The results are similar to those obtained using the 2018 AMI dataset and show that the phase identification algorithm can identify all the types of phase connectivity accurately.

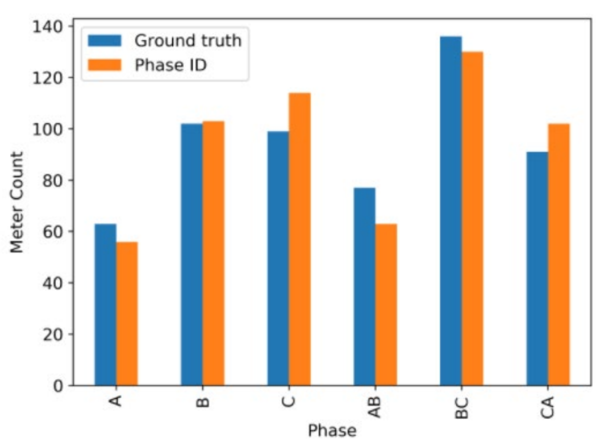

Figure 29. Phase identification results of Feeder A using 2019 AMI dataset

The detailed breakdown of the AMI meter counts in each of the training, testing, and full datasets of phase identification are shown in Table 11. For each type of phase connectivity, 30% of the meters were selected randomly along with their ground truth phase connectivity for the training dataset. The phase identification accuracies on the testing, training, and full datasets are 86.5%, 100%, and 90.5%, respectively.

Table 11. Summary of phase identification results of Feeder A using 2019 AMI dataset.

Dataset		Phase Connectivity						Total	Accuracy
		A	B	C	AB	BC	CA		
Full	Ground truth	63	102	99	77	136	91	568	90.5%
	Phase identification	55	98	98	56	126	81	514	
Testing	Ground truth	45	72	70	54	96	64	401	86.5%
	Phase identification	37	68	69	33	86	54	347	
Training	Ground truth	18	30	29	23	40	27	167	100%
	Phase identification	18	30	29	23	40	27	167	

The geographic distribution of the AMI meters for which the phase connectivity identified by the algorithm match the ground truth is shown in Figure 30. The meters are distributed all over the feeder; thus, the algorithm can detect the correct phase connectivity in all the feeder neighborhoods.

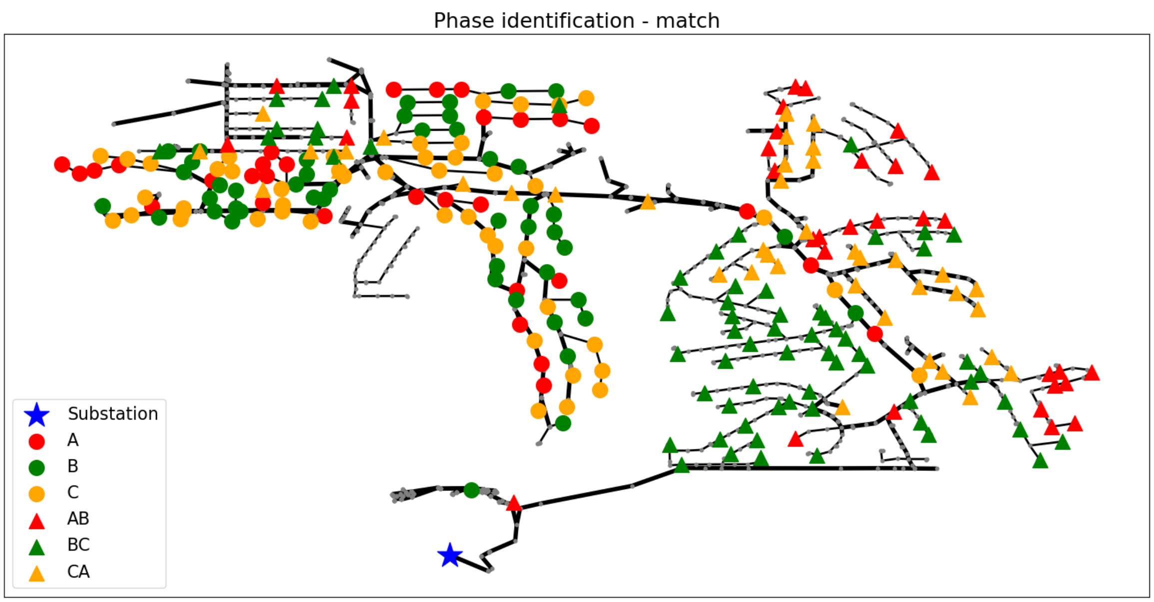

Figure 30. Locations of AMI meters for which the phase connectivity is identified correctly

The locations of the AMI meters where the identified phase connectivity does not match the ground truth are shown in Figure 31. The correct phase connectivity according to the ground truth is shown in this figure at these locations.

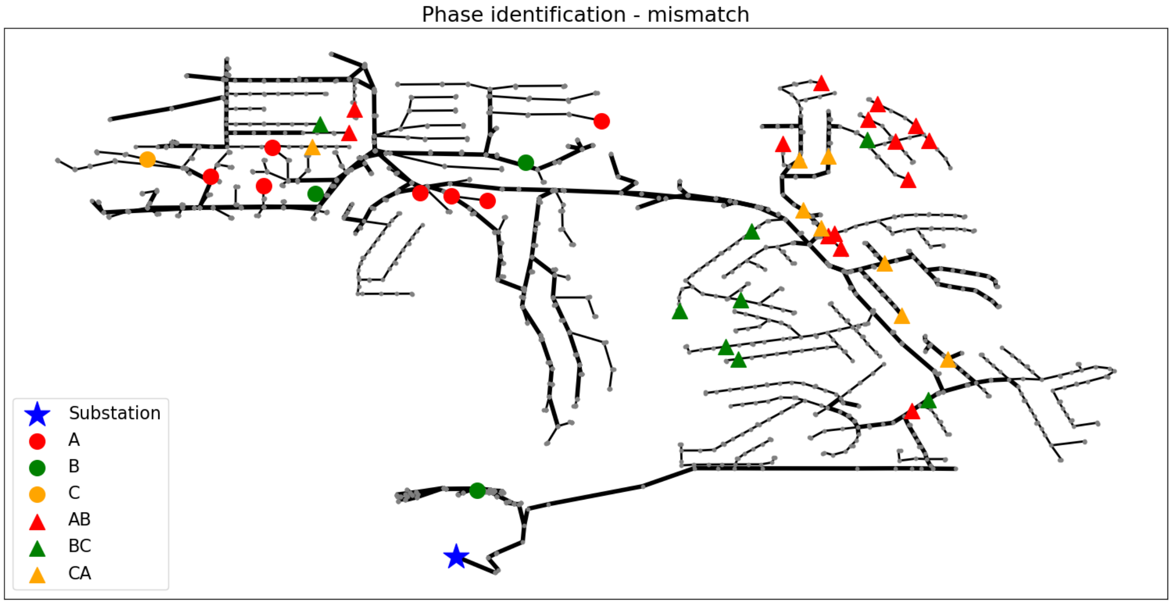

Figure 31. Locations of AMI meters for which the phase connectivity is identified incorrectly

Phase Identification in Feeder B using 2019 AMI Dataset

The phase identification algorithm was applied to the 2019 AMI dataset of Feeder B. This dataset has the average voltage magnitude time series data for 857 AMI meters for the full 2019-year period. The AMI data for two meters per service transformer were available in this dataset in addition to the field validated phasing information for these meters. The field validated phasing information was considered the ground truth. The phase identification results are shown in Figure 32. The ground truth phasing distribution in this figure indicates this feeder primarily has phase-to-neutral AMI phase connectivity. A small number of meters are connected to phase-to-phase.

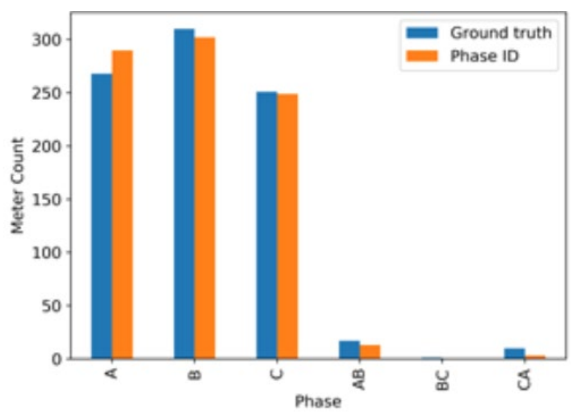

Figure 32. Phase identification results of Feeder B using 2019 AMI dataset

The detailed breakdown of the AMI meter counts in each of the training, testing, and full datasets of phase identification are shown in Table 12. For each type of phase connectivity, 30% of the meters are selected randomly along with their ground truth phase connectivity for the training dataset. With the phase connectivity identified accurately for 809 out of 857 meters in the testing set alone, the phase identification accuracy is 94.4% on the testing set. The phase identification accuracy on the training and full datasets are 100% and 92%, respectively.

Table 12. Summary of phase identification results of Feeder B using 2019 AMI dataset

Dataset		Phase Connectivity						Total	Accuracy
		A	B	C	AB	BC	CA		
Full	**Ground truth**	268	310	251	17	1	10	857	94.4%
	Phase identification	260	293	241	12	0	3	809	
Testing	**Ground truth**	188	217	176	12	1	7	601	92%
	Phase identification	180	200	166	7	0	0	553	
Training	**Ground truth**	80	93	75	5	0	3	256	100%
	Phase identification	80	93	75	5	0	3	256	

The geographic distribution of the AMI meters for which the predicted phase connectivity matches the ground truth is shown in Figure 33. The meters whose phase connectivity is identified correctly are distributed all over the feeder. This indicates the algorithm can detect the correct phase connectivity in all the feeder neighborhoods.

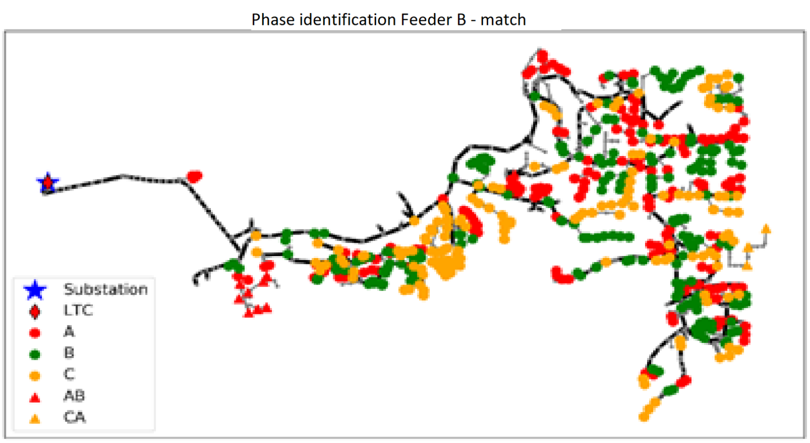

Figure 33. Locations of AMI meters for which the phase connectivity is identified correctly

The locations of the AMI meters where the identified phase connectivity does not match the ground truth are shown in Figure 34. The correct phase connectivity according to the ground truth is shown in this figure at these locations. The mismatches are generally not clustered or constrained to any specific feeder neighborhoods.

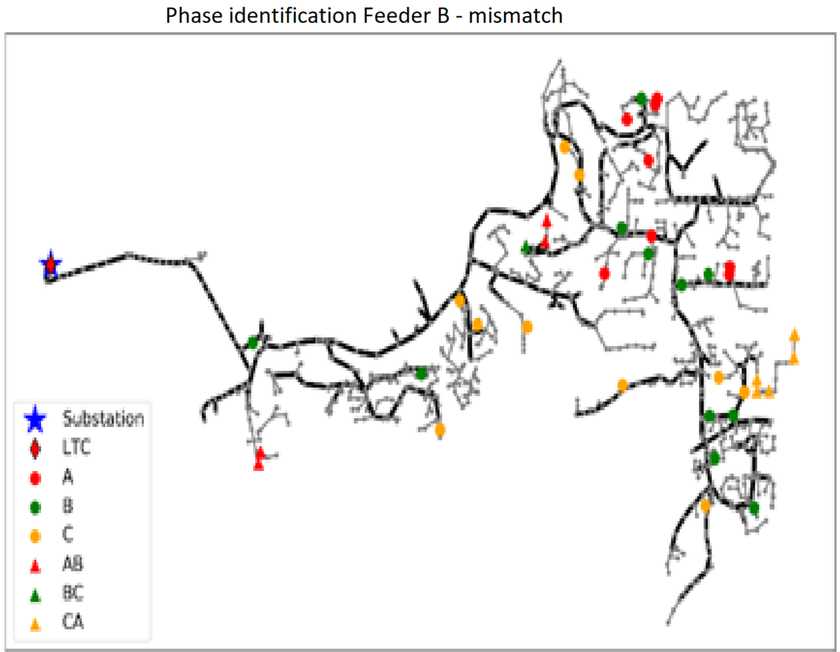

Figure 34. Locations of AMI meters for which the phase connectivity is identified incorrectly

7.4.3 Challenges

The lack of reasonably accurate data on the phase connectivity created issues in the algorithm configuration. Before the field verification, the algorithm configuration efforts primarily relied on the planning network model for the phase connectivity information. This consistently resulted in poor accuracies in any algorithm that was applied for phase identification. However, the field validated phasing information showed that the phase connectivity information in the planning network model is 60% incorrect in the case of Feeder A. Thus, the poor performance of the algorithms attempted during this project phase could have been due to using the incorrect phase connectivity database as reference.

7.5 Data-Centric Grid Operations

AMI data analytics help develop insights into distribution network operation including service quality, power consumption patterns, presence of DERs, etc. In this task, interactive 3D and 2D tools useful for visualizing essential information from vast amounts of AMI data were developed. Figure 35 below shows sample 2D visualizations on the type and duration of the voltage exceedances and the potential EV locations on the SDG&E feeder, based on the AMI data.

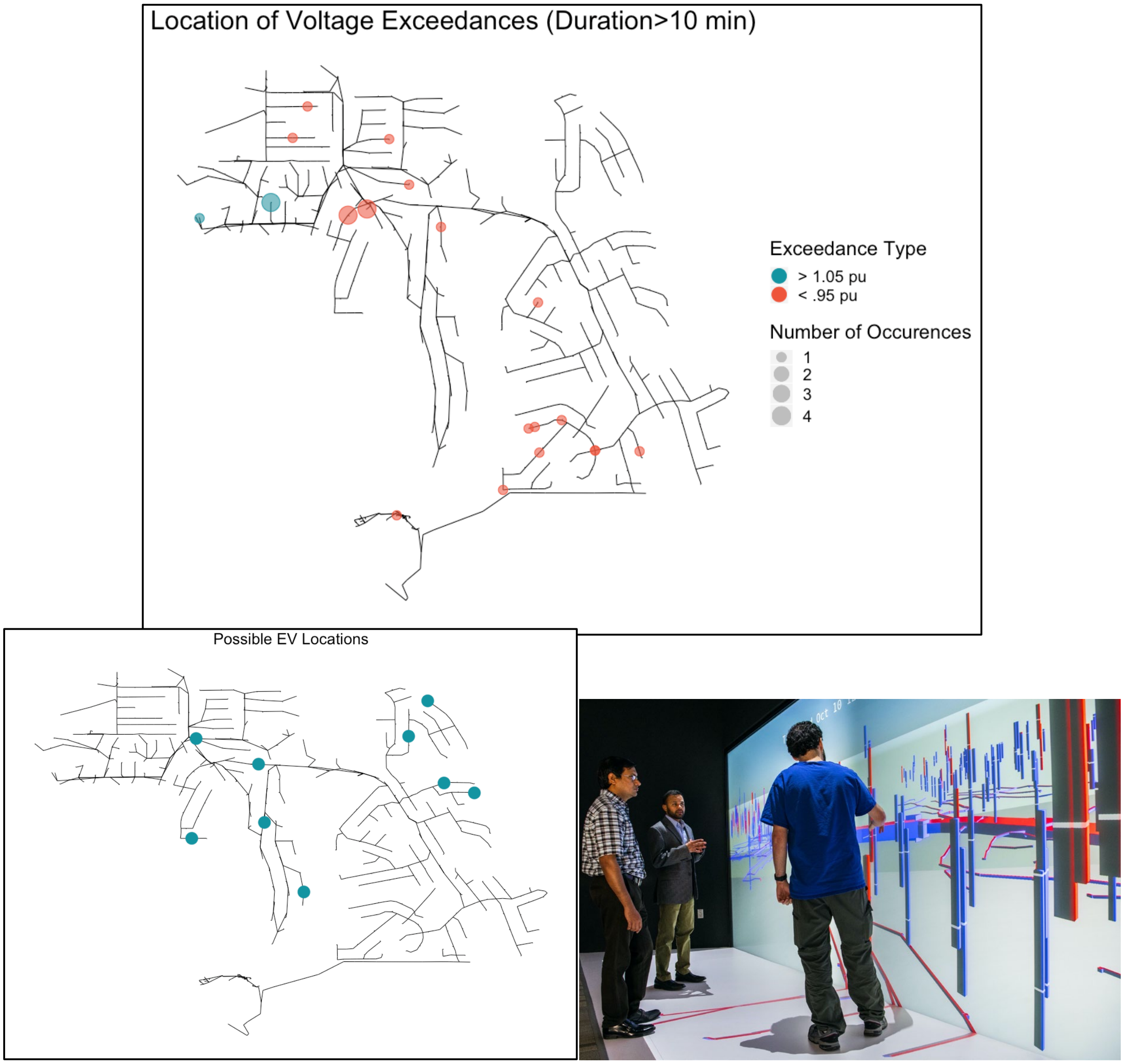

Figure 35. Interactive 2D and 3D visualization tools

AMI provides a new paradigm for utility planning, operations, and controls. The data captured by AMI can provide insights into the system dynamics at the grid edge. Utilities need tools to leverage this capability. In addition to AMI, utilities are also investing in the deployment of ADMS to prepare for future distribution operations with high levels of DERs. The ADMS is an integrated platform that combines the functionalities of distribution management systems, outage management systems, and SCADA systems for optimized distribution grid operations. Traditionally, the ADMS used the limited primary sensor measurements available on the distribution network through the SCADA system for network control decisions. With the availability of AMI measurements, there is significantly higher visibility, which can be leveraged for improved network monitoring and control.

7.5.1 Configuration and Methodology

In the voltage prediction task that attempts to predict the voltage issues in the distribution network, an AMI voltage forecasting model was prototyped for the distribution feeder. The secondaries were modeled as having three AMI data points, with the closest and furthest to the transformer as individual data points and a third one that is an aggregate of all other power consumed on the secondary. Synthetic average hourly voltage data was simulated for three and a half months. Two machine learning algorithms were used in modeling voltage time series data which can be used for forecasting. The models are learned globally and simultaneously process all AMI time series data. Simulations with various scenarios of available historical data (60, 30, and 15 days) were performed which were explicitly incorporated into the model and evaluated for performance. The performance of a model hyper parameter set when forecasted 24-hours ahead is shown in Figure 36. The plot represents an averaging over five-folds in the validation set. The model is evaluated globally on all simulated meters on the distribution feeder.

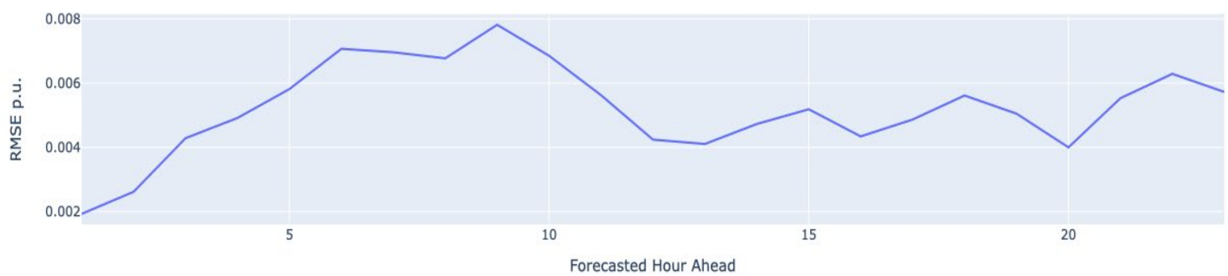

Figure 36. Twenty-four-hour forecast performance of a hyperparameter run averaged over five folds

The integration of ADMS and AMI measurements offers a unique opportunity to further modernize distribution system control. In this use case, an AMI-based data-driven volt/var control algorithm and its synergies with ADMS for distribution grid operations were evaluated using the SDG&E feeder and the AMI data. The inputs of this algorithm were AMI power and voltage measurements. The algorithm controls the LTC tap position, capacitor banks switches, and PV inverter setpoints to ensure voltage regulation.

7.5.2 Results and Discussion

Figure 37 and Figure 38 show the results from the evaluation of this algorithm. In the base case, the LTC and capacitor banks follow their local controllers, and the PV smart inverters inject power at unity power factor. In the unity power factor operation, the PV smart inverters inject active power only and no reactive power is injected or absorbed. As observed in Figure 37, many customer voltages on the secondary are experiencing high voltage exceedances in the base case. In the next scenario in which the data-driven control algorithm is enabled, the voltage exceedances are significantly reduced, and the average voltages are closer to 1.0 PU Once the voltage deviates from the preset voltage regulation set point (selected 1.0 PU in this case), the algorithm primarily raises or lowers the LTC tap position to regulate the voltages as observed in Figure 38.

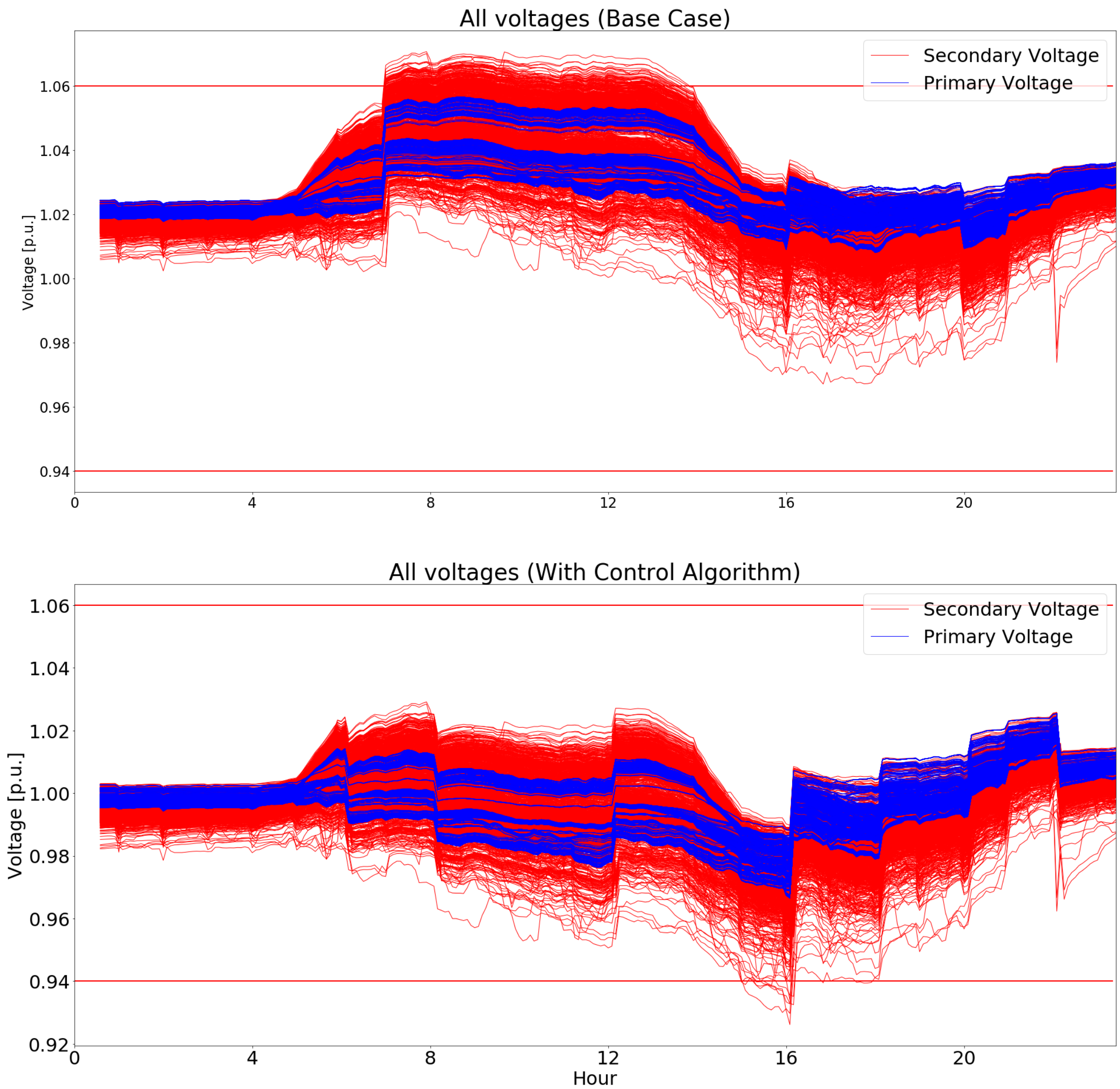

Figure 37. Comparison of Bus Voltages

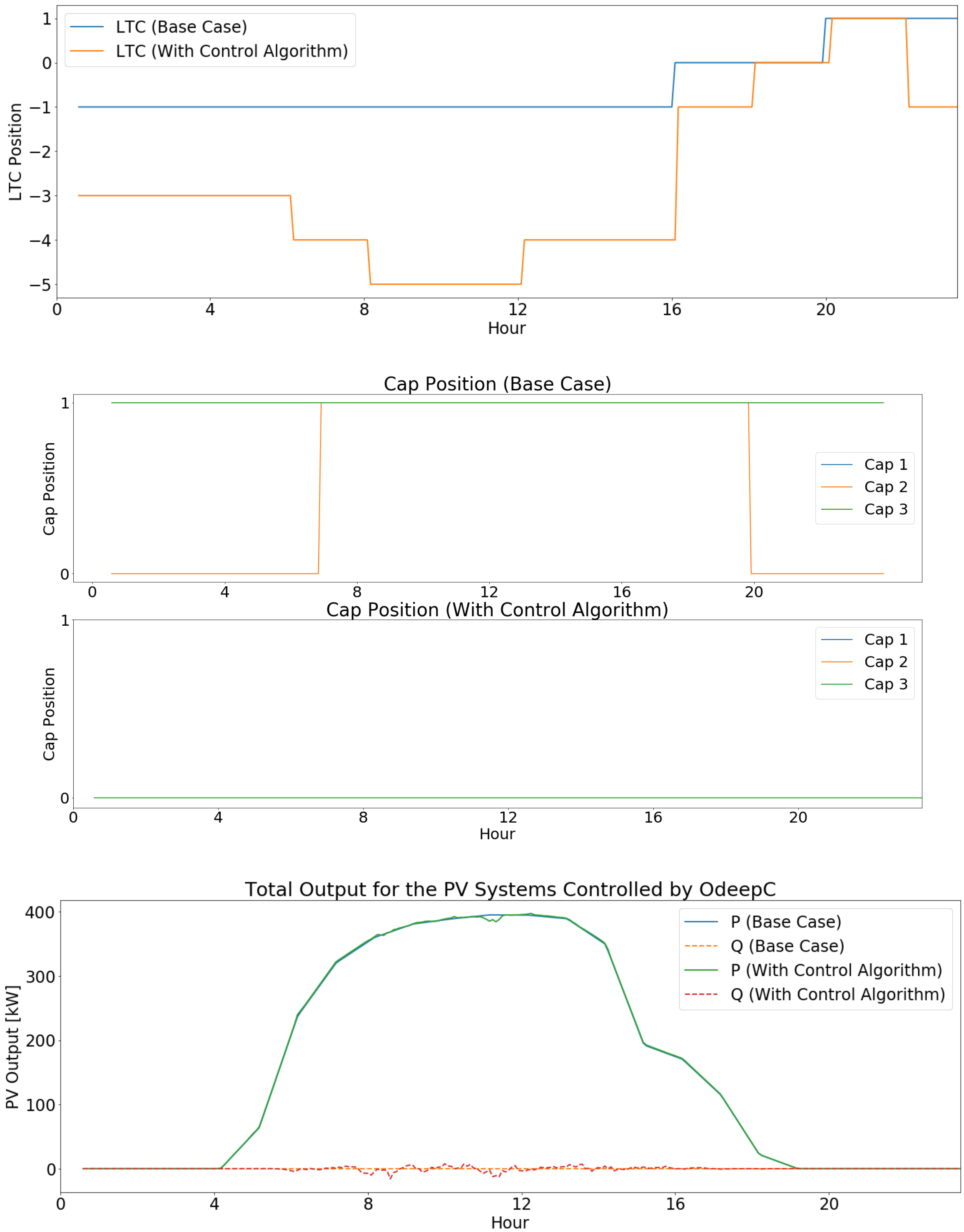

Figure 38. Comparison of LTC, capacitor bank statuses, and total PV generation

7.5.3 Challenges

The data-driven control demonstrated in this use case requires data from bellwether AMI meters every five minutes. The feasibility and scalability of this faster data reporting rate for real-time controls for all the feeders has not been explored. The utility control architecture to enable this new paradigm of grid operations is yet to be addressed.

8.0 Findings

8.1 Findings Discussion

The key findings for each of the use cases are presented in the section below.

8.1.1 PV Smart Inverter Study Key Findings

The PV smart inverter study considered various smart inverter settings from the standards. The primary objective of applied advanced inverter functionality is to support system voltage compliance. The quasi-static time-series simulation was performed for a period of 107 days with the different PV smart inverter settings enabled. When a node (bus) voltage magnitude exceeds the desirable range of 0.94 PU - 1.06 PU, it is considered a voltage exceedance (VE). The voltage exceedance node (VEN) refers to the node that has more than 12 hours of cumulative voltage exceedance in the 107-day period.

The voltage exceedance results are summarized in Table 13. The results show when the PV smart inverters are not utilized for the voltage regulation in the baseline, a significant number of nodes on the primary and secondary can experience voltages beyond the desirable voltage range for prolonged periods of time. However, these voltage exceedances significantly dropped when the smart inverter settings were enabled. While there were minor differences in the resulting voltage improvement among the different smart inverter settings, generally superior voltage regulation was experienced when the PV smart inverter settings were enabled compared to when they were disabled.

The volt-var curve slope is a key parameter influencing the voltage improvement. The Hockey Stick 2 curve setting that has the most aggressive curve slope in the high voltage region resulted in the lowest VE hours per node on the secondary where the PV systems are installed. As the PV penetration is very high (70%) on this feeder, voltage rise during the peak PV generation was the major voltage regulation issue on this feeder. The HS2 curve, with the highest curve slope, forced the PV smart inverters to absorb the reactive power more intensely compared to the other smart inverter settings and resulted in better voltage regulation in such cases.

Table 13. Summary of voltage exceedances

PV Smart Inverter Setting	Secondary		Primary	
	VE hours per node	Number of VEN	VE hours per node	Number of VEN
Baseline	23.52	752	42.83	481
CA 21	0.55	16	0.61	0
HI 14	0.21	9	0.76	12
IEEE 1547	0.47	28	0.96	14
No Deadband	1.05	37	2.84	42
HS1	0.55	16	0.61	0
HS2	0.09	3	0.91	12
Volt-Var-Watt	4.45	110	2.95	53

The voltage regulation device operations per day are summarized in Table 14. The legacy device operation counts did not vary significantly with different PV smart inverter settings, except in the case of volt-var-watt setting. However, the volt-var-watt setting resulted in the highest number of voltage exceedances as shown in Table 14 compared to the other cases when the smart inverter settings were enabled.

Table 14. Summary of legacy voltage regulation device operations

PV Smart Inverter Setting	LTC tap changes per day	Capacitor bank status changes per day
Baseline	12.07	5.25
CA 21	12.47	6.04
HI 14	13.75	5.03
IEEE 1547	13.81	5.42
No Deadband	13.03	5.66
HS-no compensation	12.47	6.04
HS-deeper Q	14.07	5.83
Volt-Var-Watt	7.32	1.47

8.1.2 Utility Planning Network Model Anomaly Detection Key Findings

Distribution planning and operations rely on accurate and reliable network models. There is a high degree of uncertainty involved in the distribution network modeling due to the changes in the network and loading conditions, lack of sufficient data, assumptions, and incorrect data, which impact the quality of network models. Further, traditional practice ignores modeling of secondary networks. As DER penetration levels increase, improving network model quality, including secondary becomes important. With the installation of AMI, more sensor measurement data is available which can be used for improving distribution network models and keeping them current. The utility planning network model anomaly detection tool developed in this project is a key step towards realizing this goal.

The utility planning network model anomaly detection tool used both physics-based and machine learning-based methods. The physics-based method estimates the secondary network parameters using limited AMI measurement data. It then estimated the primary network voltages where the sensor data were not available. The machine learning-based method used the estimated primary voltages to build machine learning models for each service transformer secondary which can be used for subsequent estimations of the primary network voltages. Below are the key findings from this task:

Physics-based Method

The physics-based method used constrained optimization to estimate the secondary network parameters based on the AMI measurement data [20]. Existing approaches for this application assume that secondary topology is known, or the AMI data for all the customers on a given secondary is available. The fact that these two assumptions do not hold true introduced some initial difficulties in the algorithm configuration. Further, it was found that the AMI data used in this project do not include any information such as reactive power or the voltage angle needed to estimate the reactance of the secondary lines. It was found that the primary voltage estimates from the physics-based algorithm were consistently higher than the actual primary voltages from the simulations, likely due to the approximations made for the data that was unavailable.

Machine Learning-based Method

The machine learning-based method used random forest regression to build the equivalent machine learning models for each service transformer secondary [21]. While the primary voltage estimates from the machine learning models were fairly accurate, building these models requires primary voltage data as training data which is typically not available. Therefore, the primary voltage data from the physics-based method was used as the training data for building the machine learning models. It was observed that the voltage estimates from the combined method that uses both the physics-based and machine learning-based methods accurately matched the primary voltages obtained from the simulations.

Lack of Primary Sensor Data

The primary network voltage data from selected primary buses was supposed to be collected according to the original plan. However, the primary meters were not installed due to some practical constraints. The tool validation process relied more on the simulations due to the lack of primary measurement data from the field.

8.1.3 Phase Identification Key Findings

The phase identification algorithm identified and configured in this study focused on achieving high phase identification accuracy levels on two distribution feeders. A few key parameters were influential in the selection of the algorithm and the accuracy of the phase identification results. These parameters are discussed in this section.

Circuit Connectivity

A distribution feeder can have phase-to-neutral connections AN, BN, and CN (also known or referred to as A, B, and C), and/or phase-to-phase connections, AB, BC, and CA. They also consist of single-phase and two-phase branches and connections. Some of the existing phase identification algorithms, specifically those based on the correlation and linear regression analysis, work only for the feeders having phase-to-neutral connections. When a feeder has a mix of phase-to-neutral and phase-to-phase connections, the voltage dependencies among the phases can be a challenge for the phase identification algorithm. For example, some level of voltage dynamics occurring on phase A can be seen by the meters connected to AB. When these interdependencies are high, the algorithm can incorrectly represent the phase connectivity.

The phase connectivity details of the two feeders in this study and the associated phase identification results are summarized in Table 15. The numbers represent the AMI meter counts associated with a given type of phase connectivity. The first feeder has high meter counts for all six phase connections. The second feeder has all six phase connections, most of the meters have phase-to-neutral connection. In all instances the phase identification results show high accuracy.

Table 15. Phase connectivity details and phase identification results of two feeders

Feeder		Phase Connectivity						Total	Accuracy
		A	B	C	AB	BC	CA		
Feeder 1	**Ground truth**	63	102	99	77	136	91	568	90.5%
	Phase identification result	55	98	98	56	126	81	514	
Feeder 2	**Ground truth**	268	310	251	17	1	10	857	94.4%
	Phase identification result	260	293	241	12	0	3	809	

Data Availability

The type of data available significantly influences the type of phase identification algorithm that is chosen for use. Some phase identification algorithms based on correlation analysis require voltage measurements from the substation SCADA. Specifically, phase-to-neutral and/or phase-to-phase voltage measurements at the feeder head are required depending on the meter connections present in the feeder. However, typically utilities record either phase-to-neutral or phase-to-phase voltage only at the substation. If only phase-to-phase voltage is collected for a feeder having a mix of six phase connections, these algorithms cannot be applied. In this project, only the phase-to-phase voltage measurement data at the feeder head was available in the substation SCADA data, while the studied feeders have all the six possible combinations of phase connections. As such, the correlation-based algorithms that depend on voltage measurement data from the substation SCADA could not be applied in this case.

The electrical quantities that the AMI meters measure also influence the choice of algorithm. Some regression-based algorithms require availability of both voltage magnitude and power consumption data from all the AMI meters connected to the service transformers. These algorithms cannot be applied if all customers do not have AMI meters because the voltage data from some customers would be missing.

PV Penetration Level

Most of the existing phase identification algorithms use voltage time series data. In particular, the voltage variations during a selected time period are the basis for determining the phase connectivity for these algorithms. Since the voltages are significantly influenced by the PV power generation, these algorithms may fail to identify the phase connectivity accurately. While this may not be an issue for some feeders having low PV penetration levels, this parameter should be considered for the feeders with high PV penetration.

Both the feeders used in this project have significant levels of PV generation. The PV penetration levels are 70% and 24% relative to the peak load for these feeders. The phase identification algorithm configured and tailored for the application in this project worked well for both these feeders, signifying its robustness to the PV penetration levels.

GIS Data Quality

It is a common practice to provide the known information about the distribution network to the phase identification algorithms to accomplish high accuracy levels. Specifically, the expected number of phase connections is supplied to the clustering algorithms as an input and the network topology information is used as constraints to obtain better phase mapping. However, the phase connectivity information in the GIS can sometimes be significantly inaccurate. More than 50% of the AMI meters were observed to be on different phases in the field validated data as compared to the GIS database in this project. When such high phase connectivity inaccuracies exist in the GIS, using such data as an input can result in poor phase identification results.

Bad Data

AMI measurement data is not perfect. In addition to the standard measurement errors, some AMI meters can report completely unreasonable data. The bad data should be identified and removed from the phase identification process. Otherwise, the bad data can lower the phase identification accuracy depending on the algorithm. Some phase identification algorithms, specifically those based on clustering, can identify the bad data without requiring additional processing.

Training Data

The type of algorithm used depends on many parameters including the type of phase connections present, data availability, and DER penetration levels as mentioned earlier. While unsupervised learning techniques are known to provide good phase identification results, such performance requires specific feeder characteristics. When the phase identification algorithm must work well for a wide variety of feeders, supervised learning is a better option. The training data provided to the supervised learning algorithm can supply information specific to each feeder to make it robust. As a result, the supervised learning algorithms can provide consistently high accuracy levels in the phase identification for many feeders. Note that obtaining the required training data may involve some level of field verification.

8.1.4 AMI Data-Centric Distribution System Operations:

Model-free controls

The demonstration of a data-driven method for voltage control for a feeder with high PV penetration with data from less than 10% of the meters on the feeder, proved feasible and practicable as a method for future adoption. The model-free controls also demonstrate that these methods can perform without an impedance model, and hence are more resilient to model quality errors including missing feeder data.

Pervasive Secondary Monitoring

This use case demonstrated how even if the voltages on the primary network are within the ANSI voltage limits (+/- 5%), the secondary networks might see voltages that are beyond these desired limits due to the presence of PV and the lack of accurate models to represent the secondary networks. By using AMI voltages as input for voltage control, these methods can maintain desired voltage on the secondary networks as well, thereby enabling pervasive secondary network monitoring.

Uncertainties from PV output

The method demonstrated in this use case does not require explicit modeling of PV systems or their outputs, but only the voltages as measured by the AMI meters. This obviates the need for detailed PV modeling for this voltage control algorithm, making it suitable for feeders with presence of high PV adoptions.

8.1.5 Meter-to-Transformer Mapping

In this exploratory task, the project team identified some key methods for mapping AMI meters to the correct service transformer. The project team identified recall and precision as two metrics for validating the performance of these methods. The Spearman correlation coefficient [13] had the highest score in both recall and precision. Therefore, it fits the proposed meter-to-transformer methodology best. All methods detected 97% of the incorrect records.

8.2 Updated Value Proposition

In this project, tools to benefit utilities in upgrading the distribution planning and operation practices were demonstrated. Specifically, the utility planning network model anomaly detection tool helps estimate the primary voltage based on secondary AMI data. The estimated primary voltage provides visibility of the primary network where the physical voltage sensors do not exist. Further, the estimated primary voltage based on AMI data was used to identify inaccuracies in the planning network models. The demonstration of the phase identification tool indicated that customer phase connectivity can be identified based on AMI data. Additionally, numerous simulations were performed using distribution feeder models developed based on AMI data from the field to develop insights into PV smart inverter settings.

The tools and demonstrations performed in this project promote and support the initial benefits and value proposition of greater reliability, lower costs, and increased safety as described in Section 6.0. Further, this project promotes the following additional benefits:

Societal Benefits

This project helps correct the distribution network models used for planning and operations. The improved network models lead to more efficient control decisions, and reduction in losses and outages. The smart inverter study lowers the cost of network operations by deferring the investments to maintain the desired electric service quality. Overall, this project shows potential to reduce the overall cost of electric service to customers.

Greenhouse Gas (GHG) Emissions Reduction

The efficient PV smart inverter settings may increase the PV hosting capacity of the distribution feeders, allowing more renewable generation. Improved phase balancing, volt/var optimization and other network controls based on the accurate network models further support the higher levels of renewable generation. The tools developed in this project are collectively geared toward reducing the dependence on traditional fossil fuels for our energy needs, thus lowering the associated GHG emissions. As noted in the initial benefits analysis, reducing travel associated with field visits/field verification, would also reduce GHG emissions in commercial use of the demonstrated tools.

Economic Development

This project demonstrated that the AMI data can be used for phase identification and distribution network model improvements. By developing use cases for the AMI, this project promotes the deployment of AMI and the associated communication infrastructure. Thus, it influences the market for the development of advanced sensing and communication capabilities. Further, the PV smart inverter study enables higher levels of DER adoption through efficient voltage control. With the higher levels of DER and availability of communication networks the DERs can participate in grid services with suitable incentives to customers. This project paves the way for future AMI-based distribution network operations that promote efficient use of renewable energy, where both the utility and customers economically benefit from the services provided.

Efficient Use of Ratepayer Funds

This project developed a phase identification tool that performs automated customer phase mapping based on AMI data. Traditionally, utilities perform the same task manually by sending a crew to the field for the identification of the customer phasing. This manual process, performed periodically, is expensive and time-consuming. The phase identification tool greatly simplifies this process and determines the customer phase connectivity more economically, thus providing savings for the ratepayers. The PV smart inverter results may help achieve the desired power quality using existing smart inverters without having to invest in network upgrades. This approach has the potential to reduce the cost of electric service which in turn benefits ratepayers through lower electricity bills.

9.0 Conclusions

This project demonstrated a utility planning network model anomaly detection tool, a phase identification tool, a meter to transformer mapping algorithm proof-of-concept and analyzed the impacts of PV smart inverter settings. The tools used AMI measurement data to estimate the primary voltages, identify planning model inaccuracies, and automate phase mapping. With the tool's promising results, the SDG&E team is currently examining deployment opportunities.

Several issues in the GIS data planning network models, and the AMI measurement data were detected during the algorithm development. These issues are related to the incorrect phase connectivity information; approximated load and PV profiles used in the planning network models; lack of reactive power measurements in the AMI data; and desirable voltages from SCADA. Additionally, using the AMI data from only two AMI meters per transformer and the lack of primary voltage measurement data from the field, created challenges in the algorithm development and validation. The selected feeders have significantly different characteristics in terms of phase connectivity, high PV penetration levels, and presence of underground cables. This provided an opportunity to develop algorithms that are sufficiently robust to the feeder characteristics. In the PV penetration study, it was observed that enabling the PV smart inverter settings is desirable for improving the network voltage profile. The selection of feeders with different characteristics also highlighted the disconnect between the voltage dynamics on the primary and secondary networks.

As the AMI deployments increase and more measurement data becomes available, leveraging the AMI data for the distribution system planning and operations is desirable. Relying on the automated AMI data analytics for this purpose instead of the network models is more economical and efficient as it reduces the time and effort in the manual periodic field verifications and database updates. This project's results indicate the desirability of shifting from the traditional model-based grid operations to data-driven grid operations.

10.0 Transfer Plan

10.1 Project Results Dissemination

This report is the primary documentation of this project work. It will be posted on the SDG&E's EPIC public website and filed with the California Public Utilities Commission.

The results from the project were presented in multiple conferences through peer-reviewed technical papers. The following is the list of papers developed under this project:

Published Papers:

1) J. Wang, H. Padullaparti, S. Veda, M. Baggu, M. Symko-Davies, A. Salmani, and T. Bialek, "A Machine Learning-based Method to Estimate Transformer Primary-Side Voltages with Limited Customer-Side AMI Measurements," in *IEEE Power & Energy Society General Meeting (PESGM)*, 2021.

2) M. Netto, J. Hao, H. Padullaparti, and V. Krishnan, “On the Use of Smart Meter Data to Estimate the Voltage Magnitude on the Primary Side of Distribution Service Transformers,” in *IEEE Power & Energy Society General Meeting (PESGM)*, 2021.
3) H. Padullaparti, S. Veda, S. Dhulipala, M. Baggu, T. Bialek and M. Symko-Davies, “Considerations for AMI-Based Operations for Distribution Feeders,” in *IEEE Power & Energy Society General Meeting (PESGM)*, Atlanta, GA, USA, 2019, pp. 1-5.

The project results were also disseminated to the industry through NREL’s ADMS Test Bed and DERMS Applications Industry Advisory Board (IAB) through quarterly meetings, webinars and a workshop held in October 2020. The following are the meetings where the project results were discussed.

- NREL hosted two virtual workshops that were held on November 9th and 10th, 2020. The title of the event was Advanced Distribution Management System Test Bed and Architectures for Grid-Edge Management Workshops. The event brought over 70 external participants from 45 organizations. This was the best attended ADMS workshop to date.
- NREL hosted a virtual IAB meeting on April 29, 2021. The focus was on Peak Load Management (PLM) and AMI for operations use cases. We also launched a series of webinars beginning with the Peak Load Management use case in June 2021.
- NREL hosted a virtual IAB meeting on July 22, 2021. We focused on the AMI-based, data-centric grid operations and ADMS network model quality impact on VVO use cases. We also presented the process for identifying future use cases, including an overview of the RFI.
- NREL continued the series of webinars with a presentation by Dr. Santosh Veda focused on AMI data data-centric planning and operations that showcased results from this project on October 6, 2021. This webinar had over 75 participants.

10.2 Transition for Commercial Use

The demonstrations performed in this project were supported by the Electric Program Investment Charge, a public purpose program funded by ratepayers of California’s investor-owned utilities, and by the US Department of Energy funding to NREL. These tools were then tested, validated, and demonstrated on real-world utility feeders provided by SDG&E. As discussed in Section 6, some of these tools were further validated using field verification. These tools are being examined for opportunities for deployment on SDG&E’s AMI data system. The architecture for implementing these tools is shown in Figure 39 below.

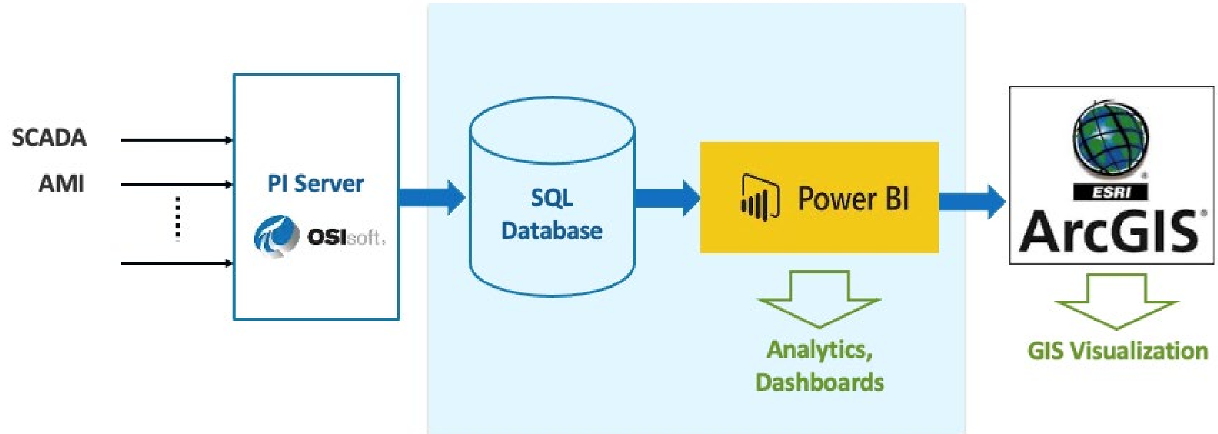

Figure 39. Architecture for potential deployment on SDG&E AMI data collection system

In addition, a subset of these tools will also be released as open-source tools for use by the industry and research for further improvement by the community at large.

11.0 Recommendations

The use cases presented in this project demonstrate the accuracy, feasibility, and rationality of using AMI data for greatly improving the planning and operations activities in the near-term, especially for feeders with high levels of PV adoption. It is recommended that specific tools (Utility Planning Network Model Anomaly Detection Tool, AMI Meter-to-Transformer Mapping, and Phase Identification Using AMI Data) be applied by the SDG&E team for other feeders. The evaluation of data-driven controls using realistic emulation capabilities of the ADMS Test bed provides a feasible demonstration for real-time data-driven control of high-PV feeders for consideration and implementation in the medium-term. Such an approach could reduce the reliance on planning models and make the operations resilient to the ubiquitous problem of poor model quality.

SDG&E will need to identify a stakeholder group within the company to lead this commercial adoption process.

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EPIC Final Report

Program	Electric Program Investment Charge (EPIC)
Administrator	San Diego Gas & Electric Company
Project Number	EPIC-3, Project 3, Module 2
Project Name	Application of Advanced Metering Infrastructure (AMI) Data to Advanced Utility System Operations
Date	December 31, 2021

Attribution

This comprehensive final report documents work done in this EPIC activity. The project team for this work included the following individuals, listed alphabetically by last name.

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Executive Summary

The objective of EPIC-3, Project 3 was to demonstrate capabilities for leveraging SDG&E's advanced metering infrastructure (AMI) system to provide actionable secondary voltage data and analysis to SDG&E staff and other prospective users. The project focus included two modules. Module 1 focused on using AMI data for a voltage sensor network, while Module 2 focused on using AMI data to identify endpoint phasing and meter-to-transformer mapping. This report describes the pre-commercial demonstration for Module 2.

This report consists of five parts. Part I contains general information about Module 2 of this EPIC project. Parts II, III and IV describe the three separate and distinct methodologies that were demonstrated in this module; where Parts II and III describe demonstrations where SDG&E worked collaboratively with external vendors, and Part IV captures the internal effort by SDG&E personnel to identifying endpoint phasing based on publicly available studies. In Part IV, no work was done on meter-to-transformer mapping. Finally, Part V contains a summary of the methodologies; findings, and recommendations; and information on technical transfer and commercialization.

PART I – General Information

This demonstration seeks to determine the feasibility of executing two use cases – AMI meter phasing and meter-to-transformer mapping while constraining the AMI input source to two meters per transformer. Through a competitive process, two vendors were selected to assist in executing these use cases.

SDG&E's AMI system provides abundant usage and voltage information with high resolution and accuracy. By using these data, the project sought to address several issues:

- Traditionally, the only way for a utility to correct its phasing model was through deployment of personnel into the field to verify meter-to-transformer connectivity and transformer-to-phase connectivity. This practice is both expensive and time consuming and further complicated by increased risk for employee safety.
- Utility circuits are increasingly more complex as new technology is integrated into the grid. With the complexity of the grid ever increasing, the need for accurate phase ID solutions becomes more prominent to promptly address issues of phase balancing and transformer loading.
- Circuit distribution information in utility systems has never been perfectly accurate. Where the information is inaccurate, it can lead to unbalanced phases, as well as overloading, and underutilization of transformers and other equipment.

There are three dimensions that describe the benefits associated with improving records accuracy of phase identification and meter-to-transformer mapping. These include distribution network reliability, increased safety, and reduced cost. However, any utility can improve records accuracy by manually validating conditions using field technicians, also known as field verification. Therefore, the true benefits of this program focus on the last two focus dimensions, increased safety and reduced cost.

The metrics used to determine success are the accuracy rates of prediction. This is simply measured by comparing the correct predictions to the total amount of endpoints. This implies that the true values for phasing and meter-to-transformer are known. For this project, field verification was used as the source of the true value even though 100% accurate field verification is not assured. In fact, through the efforts of one vendor, the project team discovered field verification rates of approximately 95%. While not perfect, this is the best means of determining the “source of truth”.

In order to demonstrate the algorithms, SDG&E selected two feeders: Feeders (circuits) A and B. Feeder A has 325 connected transformers and 5,173 connected meters, while Feeder B has 649 connected transformers and 2,393 connected meters. The voltage readings had a precision of 0.15 volts and were collected over the course of two years, from October 21, 2018, to October 20, 2020.

PART II – Methodology A

Part II captures the results of Methodology A, the first of two methodologies where SDG&E worked with an external vendor. This methodology demonstrated use of an established, data analytics platform to ingest, analyze, and evaluate end point phase identification and meter-to-transformer mapping.

In this methodology, the project team executed four distinct tasks – 1) data collection and cleansing, 2) execution of phase identification algorithms, 3) execution of meter-to-transformer mapping algorithms, and 4) evaluation of results using field verified data. During tasks 2 and 3, the vendor executed several iterations of the algorithm in order to optimize the results. Once optimized, the results were compared to field verification results in task 4. This methodology had mixed results – relatively high accuracy for phase identification with mediocre results for meter-to-transformer mapping. For phase identification, results of 98% and 97%, and for meter-to-transformer mapping, results of 82% and 79% were achieved for circuits A and B respectively.

PART III – Methodology B

Part III captures the results for Methodology B, the second of two methodologies where SDG&E worked with an external vendor. This methodology demonstrated use of an established, data analytics platform to ingest, analyze, evaluate, and display results for end point phase identification and meter to transformer mapping.

The project was organized into three tasks – 1) phase identification, 2) meter-to-transformer mapping, 3) field validation. In this methodology, data cleansing occurred during tasks 1 and 2. Data for four circuits, circuits A, B, C, and D were provided to this vendor; however, field verification data were only provided for circuits A and B. Therefore, no field validation was performed for circuits C and D. For phase identification, results of 83% and 92%, and for meter-to-transformer connectivity, results of 65% and 89% were achieved for circuits A and B respectively.

PART IV – Internal Methodology

Part IV captures the results of the internal methodology executed by SDG&E personnel and describes the demonstration based on publicly available studies. Unlike Methodology A and B, the project team focused solely on phase identification. No work was done on meter-to-transformer mapping.

The project team used an internally developed clustering algorithm based on research from publicly available sources. This methodology was executed to give the project team a baseline metric of results accuracy using simple time-series clustering. This methodology had two limitations – 1) the results output is provided in "phase groups", rather than the actual phase, and 2) the analysis is restricted to single-phase, line to neutral meters. Results for phase identification were 72.5% and 95.5% for circuits A and B respectively.

PART V – Summary and Recommendations

All methodologies agree that automatic phase identification is achievable at acceptable levels of accuracy using only two meters per transformer. Meter-to-transformer connectivity, however, proved less precise. Commercialization of any of the methodologies is not recommended given the constraint of two meters per transformer. This constraint minimizes the amount of infrastructure support needed to transfer data from meters to a centralized location for further processing and therefore reduces cost. This cost minimization constraint is a primary focus of the demonstration. Advancements in machine learning, advanced data mining, and artificial intelligence coupled with reduced data storage costs and improved network throughput have created numerous opportunities to use AMI data beyond the use case of meter reading and billing. The project team does not recommend pursuing the successful use case in this study, analytical based phase identification, as a single use case. Rather, it recommends exploring additional use cases that would benefit a wider audience. Exploring additional use cases is beyond the scope of this EPIC project.

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PART I

1.0 Introduction

The objective of EPIC-3, Project 3 was to demonstrate capabilities for leveraging SDG&E's advanced metering infrastructure (AMI) system to provide actionable secondary voltage data and analysis to SDG&E staff and other prospective users. The project focus included two modules. Module 1 focused on using AMI data for a voltage sensor network, while Module 2 focused on using AMI data to identify endpoint phasing and meter-to-transformer mapping. This report describes the pre-commercial demonstration for Module 2.

This report consists of five parts. Part I, this part, contains general information about Module 2 of this EPIC project. Parts II, III, and IV describe the three separate and distinct methodologies that were used in the demonstration. Parts II and III describe demonstrations where SDG&E worked collaboratively with external vendors. Part IV captures the internal effort by SDG&E personnel to identifying endpoint phasing based on publicly available studies. In this last methodology, no work was done on meter-to-transformer mapping. Finally, Part 5 contains a summary of the methodologies; findings and conclusions; and information on technical transfer and commercialization.

2.0 Module Objectives

This project module seeks to demonstrate and assess analytical approaches to predict phase identity and meter-to-transformer mapping. While endpoint phasing and meter-to-transformer mapping has been accomplished using analytical methods in the past, this project attempts to accomplish this using data from only two meters per transformer. The project module provides proof of concept by using algorithms that can consume SDG&E's AMI, SCADA, GIS, and other relevant data to determine phasing and meter-to-transformer connectivity on two sample circuits. Data from these two sample circuits were used in all three methodologies to help aid in consistency of results. A goal of the pre-commercial demonstration is to identify a path for SDG&E to replace or reduce the existing expensive methods of verifying phasing and meter to transformer mapping with a reliable and accurate analytical approach.

3.0 Issues and Policies Addressed

The AMI system provides abundant usage and voltage information with high resolution and accuracy. Recent advances in machine learning models make it possible to identify phase and predict meter-to-transformer connections through the analysis of this high-frequency data. Issues addressed during this project include:

- Traditionally, the only way for a utility to correct its phasing model was through deployment of personnel into the field to verify meter-to-transformer connectivity and transformer-to-phase connectivity, and thereby identify endpoint phasing. This practice is both expensive and time consuming and further complicated by increased risk for employee safety.
- Utility circuits are increasingly more complex as new technology is integrated into the grid. With the complexity of the grid ever increasing, the need for heightened monitoring capabilities on

utility grid equipment is growing. In particular, the need for accurate phase ID solutions becomes more prominent to promptly address issues of phase balancing and transformer loading.

- Circuit distribution information in utility systems has never been perfectly accurate. This inaccurate information can lead to unbalanced phases, as well as overloading, and underutilization of transformers and other equipment. Overloading shortens the life expectancy of distribution equipment and in the most extreme cases, presents a safety hazard. Underutilization leads to unnecessary capital expenditures on additional equipment. Imbalanced phases result in higher technical losses in transfer and increases operational costs.

The notion that voltage data can be used to solve phase ID records inaccuracy relies on the fact that voltage fluctuations on two meters have a closer correlation when they are on the same transformer as compared to when they are on separate transformers. The same principal applies to the meters on the same phase on a feeder. If this voltage data can be leveraged to create an accurate connectivity model, then all the benefits associated can be accessed at a fraction of the cost and much faster than is possible with field verifications.

4.0 Project Focus

The focus of the project was to test whether phase identification and meter-to-transformer can be performed accurately using existing data from AMI, SCADA and GIS data sources. More specifically, the purpose of this project is to test the performance of vendor and internally developed algorithms with a limited amount of data. For each transformer on the two feeders, two meters were chosen for voltage data collection. To mitigate the concern of overwhelming network traffic if every meter was included in the analysis, only a subset of data was used. If the phase identification and meter-to-transformer performance has an acceptable level of accuracy on such a limited dataset, this proves that data-driven solutions are viable in areas with low network bandwidth. Low network utilization could also cut the cost of data transferring, data storage, and data processing. Finally, this project will also shed light on promising directions of further research.

5.0 Project Scope Summary

The project scope is to discover, demonstrate, evaluate, and validate vendor and internally developed methods to automatically identify meters' phasing information and meter-to-transformer mapping.

Testing of the algorithms to provide a baseline metric of results accuracy using time series clustering methods is performed utilizing five-minute interval AMI voltage data at all service transformers for the selected feeders. For this project, SDG&E selected two feeders: Feeders (circuits) A and B. Feeder A has 325 connected transformers and 5,173 connected meters. It serves a relatively dense suburban neighborhood with a mix of overhead and underground wiring and a relatively even mix of line-line (L-L) and (L-N) phasing on the transformers. Feeder B has 649 connected transformers and 2,393 connected meters. It serves a spread-out suburban neighborhood with predominantly underground wiring and predominantly line to neutral (L-N) phasing on the transformers.

The data used for the phase ID and meter-to-transformer solutions consisted of voltage readings for two meters per transformer across the two feeders. The voltage readings had a precision of 0.15 volts and were collected over the course of two years, from October 21, 2018, to October 20, 2020.

Primary outcomes include:

- Evaluation of data analytics for phase identification and meter-to-transformer mapping
- Demonstration using SDG&E's SCADA, GIS, and AMI data to predict phase ID and meter-to-transformer mapping
- Demonstration of any additional analytical methods/applications of AMI data to enhance the electric utility's operations
- Recommendations for full-scale deployment for operational use
- Support to SDG&E in determining costs and benefits for adoption of the demonstrated methods into commercial practice

6.0 Benefits Analysis/Metrics

6.1 Initial Benefit Estimate and Value Proposition

The initial benefit estimate focused on the following core areas:

- Improved distribution network reliability
    - Allow for more accurate phase balancing
    - Improved data for asset management, especially transformer utilization
- Increased safety
    - Better identification of impacted endpoints during outages
    - Better guidance for trouble teams
    - Lower risk of injury by reducing field visits
- Reduced cost
    - Reduce the need to store exceptionally large data sets/reduce AMI related capital infrastructure expense
    - Decrease the volume of costly field visits
    - Reduce data mining and field visit requirements using readily available data – AMI, SCADA, GIS
    - Increase accuracy in forecasting – reduce/delay capital expenditure

These dimensions describe the benefits associated with improving records accuracy of phase identification and meter-to-transformer mapping. Any utility can improve records accuracy in these two metrics – phase identification and meter to transformer mapping – by manually validating conditions using field technicians. However, field verification is time consuming, costly, and represents a safety risk to field personnel. Therefore, the true benefits of this program focus on increased safety and reduced cost.

6.1.1 Increased Safety

Automated asset phase mapping reduces the need for manual field verification on asset phasing, thereby reducing potential SDG&E employee contact with live wires when manually identifying phase. In addition to reducing electrical hazards, reduction of field visits translates to fewer truck rolls and the risks associated with cumulative miles traveled.

Improvements to phase balancing also supports the avoidance of transformer overload failures and provides better loading data to mitigate unsafe loading conditions that could result in hazardous exposure to equipment explosions or downed wires.

6.1.2 Reduced Cost

Network Storage/Reduction in AMI Capital Infrastructure

One primary focus of this project is to determine if accurate phasing and meter-to-transformer mapping can be accomplished using only two meters per transformer. At the time of project initiation, this appeared unprecedented. Past studies and existing commercially available products use a much higher ratio of meters to transformers. By achieving a high level of accuracy using only two meters per transformer, the requirement of storing these data is drastically reduced, thus reducing the cost of network storage.

AMI capital infrastructure, specifically the back-haul network, is not designed to transfer substantial amounts of data. They are typically designed to transmit only what is needed for reading meters. By using the AMI infrastructure to carry, not only meter reading data, but also voltage data, the network capacity requirement increases dramatically. By minimizing the amount of data needed from the meter to voltage readings from only two meters per transformer, the requirement to increase back-haul capacity is minimized. Therefore, the overall cost is reduced.

Reduction in Field Visits

Only a subset of field visits can be eliminated by using an algorithm. Accuracy well above 95% can be achieved using field visits. Utilities *will* update their systems records (OMS, GIS, etc.) using field verified results because it is a time proven method. However, many utilities will *not* update their system records when phasing and meter-to-transformer mapping is verified using an algorithm, largely because the process is new and unproven. Therefore, the reduction in field visits will be limited to those operational use cases where phasing and meter-to-transformer mapping *can* be accomplished without field verification, that is, with the aforementioned algorithm. At this time, these operational use cases are limited to:

- Distribution load balancing
- System planning
- Outage response (meter-to-transformer mapping only)
- Model validation – specifically where system records may be inconsistent with reality and an algorithm is used in conjunction with field validation
- Distributed energy resource (DER) hosting approval

- Future analytics such as transformer utilization, system planning analysis, voltage analytics and outage management

Using Available Data

By using readily available data, such as those from SCADA, the MDMS (AMI data), etc., additional data mining and field visits can be eliminated. At SDG&E, data from many systems are stored in OSIsoft PI and is readily available for analysis, and therefore eliminates the need to capture and store data using other methods.

Increase Accuracy in Forecasting

Accurate phase information is needed to effectively plan distribution assets. Distribution planning engineers will access available records and then use that information to forecast capital expenditures. By having access to an easy method of determining phasing information, planners can more efficiently gather the information they need to make the right decisions. This in turn can result in a reduction or delay in capital expenditure. This of course assumes that the results returned from the algorithm are sufficiently accurate.

6.2 Initial Selection of Metrics

The metrics used to determine success are the accuracy rates of prediction. This is simply measured by comparing the correct predictions to the total amount of endpoints. Obviously, this implies that the true values for phasing and meter-to-transformer are known. For this project, field verification was used as the source of the true value even though 100% accurate field verification is not assured. In fact, through the efforts of other vendors, the project team discovered field verification rates of approximately 95%. While not perfect, this is the best means of determining the “source of truth”.

There is no industry standard for minimum level of accuracy. Further, a minimum level of accuracy depends on the operational use case relying on the data and the safety risk to employees. As noted above, using an algorithm-based phase identification method may never be acceptable when employee safety is involved. However, using this analytical method for distribution load balancing, system planning, model validation, etc., may be perfectly acceptable with each specific use case requiring a minimum value of accuracy. In general, accuracy of greater than 95% is considered acceptable.

PART II

Part II captures the results of Methodology A, the first of two methodologies where SDG&E worked with an external vendor.

PART II List of Illustrations

Part II List of Tables

Part II List of Acronyms

Acronym	Acronym Description
AMI	Advanced Metering Infrastructure
DER	Distributed Energy Resources
EPIC	Electric Program Investment Charge
EV	Electric Vehicle
GIS	Geographical Information System
GMSV	Google Maps Street View
L-L	Line to Line (phasing)
L-N	Line to Neutral (phasing)
MDMS	Meter Data Management System
Phase ID	Phase Identification (meter to phase connectivity)
RD&D	Research, Development and Demonstration
SaaS	Software as a Service
SCADA	Supervisor Control and Data Acquisition
SDG&E	San Diego Gas and Electric Company
TD&D	Technology Demonstration and Deployment
VRTU	Voltage at Remote Terminal Unit

1.0 Overview

Methodology A demonstrated use of an established, data analytics platform to ingest, analyze, and evaluate end point phase identification and meter-to-transformer mapping. The scope of this pre-commercial demonstration was divided into four distinct tasks:

1) Collect Data
2) Run phase identification
3) Run meter-to-transformer
4) Evaluate Accuracy with Field Verifications

1.1 Collect Data

The data used for both the phase identification and meter-to-transformer solutions consisted of voltage readings for two meters per transformer across the two feeders. There was also a supplemental equipment dataset containing location and address information for the meters and transformers within both feeders. The location dataset was used in the meter-to-transformer algorithm. It was also used to visualize and present the results of both phase identification and meter-to-transformer.

In addition to data collection, data transfer and clean-up had to be performed prior to running the phase identification and meter-to-transformer solutions. A fraction of meters had to be omitted from the analysis due to incomplete or corrupted data. Likewise, a fraction of time intervals also had to be excluded due to "frozen" reads during periods such as the daylight savings days in March and November. Location data also required a clean-up step as the latitude and longitude data for meters was known to be inaccurate in many cases. Where possible, accurate geolocation data was extracted from meter addresses. For most of the meters this sufficed, however a fraction of meters had addresses that could not be accurately located on a map or were located outside of the extent of the feeder. These meters were also omitted from the meter-to-transformer analysis.

1.2 Run Phase Identification

The phase identification solution was run on more than 1,500 meters from the two selected SDG&E feeders. The intended outcome was that each meter would be assigned to one of three phases. This assumed that, on a given feeder, meters would be predominantly connected to either L-N phases (A, B, and C) or L-L phases (AB, BC, and AC), but not both. Initial results from field verification indicated that this was not the case, and so the assumption was removed for the final run. In the final run, the phase identification solution assigned each meter to one of six possible phases (A, B, C, AB, BC, AC) for the given feeder.

Phase predictions for each meter were accompanied by various descriptive metrics including metrics that reflected the confidence of the algorithm. Phase predictions were presented in tables and on interactive maps and charts.

1.3 Run Meter-to-Transformer

The meter-to-transformer solution was also run on over 1,500 meters. Typically, the results from this meter-to-transformer solution falls into two categories. The first category of results is referred to as the *exception views*. Each exception view is a table containing meters or transformers for which no meter-to-transformer prediction can be made. The list of typical exception views is provided below:

1) Transformers with 0 connected meters
2) Transformers with 1 connected meter
3) Transformers with 2 connected meters
4) Transformers with poor internal correlation
5) Transformers with bad latitude/longitude data
6) Meters on transformers with 1 connected meter
7) Meters on transformers with 2 connected meters
8) Meters on transformers with poor internal correlation
9) Meters with bad latitude/longitude data

For mathematical reasons, voltage correlation analysis cannot accurately correct errors in any of these situations without introducing new errors (Error Correction Code, 2021). A more in-depth discussion of the relevant mathematics can be found in Part II, Section 4.1 Findings Discussion. The exception views are provided so that stakeholders are aware of the portions of the connectivity model that cannot be verified using voltage correlation analysis.

The second category of results are the meter-to-transformer predictions. Each meter not included in an exception view gets assigned to the transformer that the algorithm selects as the best match. In cases where the prediction of the algorithm disagrees with the prior connectivity model, the prediction is often referred to as a meter-to-transformer "suggestion".

Due to the nature of the voltage dataset collected, every single meter should fall into Exception View 7, "Meters on transformers with 2 connected meters". The dataset also contained transformers that had voltage readings for a single connected meter and some transformers that had voltage readings for three connected meters. Nonetheless, under normal conditions, very few predictions would be made if the meter-to-transformer solution were run on this dataset. To best answer the question, "Can voltage data for two meters per transformer be used to accurately predict and correct meter-to-transformer connectivity on a given feeder?", the solution was reconfigured to give predictions in the case where there were two or more meters on a transformer in the prior connectivity model.

The final exception views and predictions were presented in tables and accompanied by interactive maps and charts.

1.4 Evaluate Accuracy with Field Verifications

To evaluate the success of the demonstrations of meter-to-transformer and phase identification, the accuracy of predictions from each solution had to be measured. To evaluate accuracy, a 100% accurate source of truth must be established to measure against. Once the source of truth was established, it was contrasted with the phase identification and meter-to-transformer predictions in a confusion matrix (Tyagi, 2021), a tool for predictive analysis in machine learning. The confusion matrix provides information about how a machine classifier has performed, matching suitably classified examples corresponding to misclassified examples.

The formula for accuracy is:

$$\frac{Correct\ Predictions}{Total\ Predictions} = Accuracy$$

The source of truth selected for this demonstration was field verification. This field verification was performed in advance of running phase and meter-to-transformer identification, but the field verification results were not disclosed until after the initial runs.

After the initial runs were conducted, time was allotted to adjust or reconfigure the phase identification and meter-to-transformer solutions, if it was believed that a significantly better accuracy could be achieved. The phase identification and meter-to-transformer predictions after adjustment were used to calculate the final accuracy values.

While analyzing the results from this demonstration, it was discovered that the field verifications were not 100% accurate, as was believed initially. This had a significant impact on the interpretation of the final accuracy values.

2.0 Methodology Approach

2.1 Initial Selection of Metrics

The metrics used to determine success or failure for both phase and meter-to-transformer identification are the accuracy rates. There is no industry standard cutoff for success and failure accuracy rates. Higher accuracy rates are generally preferred, and rates of maximum trust are required for issues involving safety.

As mentioned above, many utilities will not update their system records when phasing and meter-to-transformer mapping are verified using an algorithm. In this case, meter-to-transformer and phase identification models can still help reduce field visits and increase utility company's records quality, but with only limited help. When model prediction has a higher accuracy rate than the expected accuracy of utility records, model results should be used to replace the utility records.

Here is an example that, although oversimplified, provides some insight into the selection of model prediction vs field verification. Assume that for one feeder the utility company has only 50% confidence in their records, and that the utility is capable of field results with a modest 95% accuracy rate. Also, assume that the machine learning model has a modest 90% accuracy rate. In this situation, one would expect that out of the 1,000 meters on the feeder, the utility records are wrong for 500, and the model predictions are wrong for 100, all randomly distributed as in Table 1 below.

Table 1. Example One

	False	True	Total
False	50	50	100
True	450	450	900
Total	500	500	1,000

Without using the model, the utility could field verify every meter on the feeder and improve the overall accuracy of the connectivity model to 95%. However, by using the machine learning model they could achieve an even higher accuracy with almost half the work. Also assume that when both records and predictions are wrong, the chance that they are the same is one third. In the context of meter-to-transformer this would mean that a meter was incorrectly found on the same transformer by both the existing utility records and the machine learning algorithm. In the context of phase identification this would mean the meter was incorrectly found on the same phase.

By using the algorithm, the utility would not have to visit all 1,000 meters, but could prioritize to visit all the unmatched meters, which is 450 + 50 + 2/3 * 50 = 533 and with 95% accuracy rate, get correct records for 506 meters.

Therefore, after a round of field verifications, the records would still be incorrect for 17 of the meters in the top-left cell of Table 1, for which the model prediction matches utility's wrong records, and the 27 meters for which field verification was inaccurate. The updated accuracy rate on this feeder would then be 96%. That is higher than the field verification accuracy rate, with only 533 field verifications as opposed to 1,000.

The utility could iterate this process and visit the unmatched meters for the second round and increase the accuracy rate even more. In this case, the model helps setting target on the right meters for field visits, but since model accuracy is lower than the field verification accuracy rate, field verifications are still required to achieve maximum accuracy.

If the model has a higher accuracy than field verification, such as 99%, the story changes.

Table 2. Example Two

	False	True	Total
False	5	5	10
True	495	495	990
Total	500	500	1,000

Following the same logic, the utility would have to visit only 503 meters if they wished to field verify the discrepancies. Compared to example one, the number of meters visited decreased by only 6%. This is caused by the assumption the utility has 50% confidence in their existing connectivity model. In such a case, even with a 100% correct back-office solution, to field validate the unmatched meters the utility would have to send out workers to 500 meters.

In this example field verification would get correct records for 478 meters, a 95% accuracy rate. The utility would end up with wrong records for two meters out of the top left cell of the matrix above, and 25 meters for which field verification fails to provide a correct answer. Overall, the accuracy rate for utility's records is 97%, higher than the field verification accuracy rate, but lower than the model prediction accuracy rate. Including the field verifications actually *reduced* the overall accuracy of the system. When the accuracy of a model is significantly greater than the accuracy of field verifications, the need for truck rolls is removed entirely. It makes the most sense to use model prediction as the single method to update the records.

2.2 Description of Pre-Commercial Demonstration

The purpose of this project is to assess analytical approaches to phase identification and meter-to-transformer mapping to enhance utility system operations and thereby improve the customer experience, in terms of reliability, safety and costs.

2.2.1 Use Case Description

The two use cases that were executed in this project were phase identification and meter-to-transformer mapping. Both use cases were executed using voltage correlation analysis.

Phase Identification Use Case

The use case of phase identification involves making predictions and corrections for the meter to phase connectivity within a feeder. On a feeder, electricity is typically distributed using three powered lines. Each line has a different phase of alternating current, each separated from the other two by 120°. Often these three phases are labeled A, B, and C. In between the powered distribution lines and residential electric meters, transformers are used to reduce voltages to safe levels. There are many ways to wire transformers between the power distribution lines. The result is the low voltage wires coming from a single-phase transformer can transmit electricity in one of six possible phases (A, B, C, AB, BC, AC), depending on the wiring configuration of the transformer. These phases are split into two groups. The L-N phases occur when the transformer is wired between a powered distribution line and a neutral line. They conduct electricity with a phase corresponding to the phase of the powered line. The L-L phases occur when the transformer is wired between two powered distribution lines. They conduct electricity with a phase corresponding to the difference between the two powered distribution lines. Technically speaking each phase also has an inverse phase (i.e. -A, -B, -C, etc.), but in this project there is no need to distinguish between phase A and phase -A for example, because a load on either phase will place a load on the phase A distribution line. Utilities typically keep track of the transformer to phase connectivity, because all the meters connected to a single-phase transformer share the same phase. For this use case, however, meter-to-phase connectivity is predicted. The primary reason for this is the meter-to-transformer connectivity is also in question. Accurate meter-to-phase connectivity is sufficient for use in phase balancing. Meter-to-phase connectivity can also be used to cross-validate meter-to-transformer connectivity. Another reason that meter-to-phase connectivity is predicted, and not transformer-to-phase connectivity, is that voltages are not metered on the transformers.

Meter-to-Transformer Use Case

The use case of meter-to-transformer mapping involves making predictions and corrections for the meter-to-transformer connectivity within a utility territory. Transformers typically have anywhere from one to dozens of connected meters. Each transformer typically serves a parcel of land within which it resides. Accurate meter-to-transformer connections are plotted on a map represented by lines connecting meters to the appropriate transformers and displayed as a collection of starburst patterns with very few crossing lines. Meter-to-transformer connectivity errors often manifest on the borders between two transformer “domains”. For example, imagine two transformers serving meters on the same suburban street. The arrangement of meter-to-transformer connections might look something like the graphic in Figure 1.

Figure 1. Typical meter-to-transformer connectivity on a suburban street

In this example the meters most likely connected to the wrong transformer are the four in the middle. This is because they lie on the border between two transformers. If a tree falls and some of the wiring on this street must be redone, it is quite possible they could be rewired to a different transformer. Errors like these are difficult to find. Distance is not a good metric to use because both transformers are close enough to be possible. Street addresses are also insufficient for the same reason. In cases like these, voltage correlation analysis shines as a means of uncovering the correct connectivity. By combining voltage reads from the meters, a robust estimate for transformer voltage is constructed for each transformer. After this, the voltage correlation between each meter and each transformer is calculated. Meters tend to correlate to the transformer they are connected to. There are, however, mathematical limitations to this technique. To create a robust estimate for transformer voltage a sufficient number of connected meters is necessary. With three connected meters it is possible to correct a single error without introducing more errors into the connectivity model. With more meters it becomes possible to fix two or more mistakes on a transformer. At two meters per transformer, it is possible to detect the presence of a single error, but it is not possible to correct that error without introducing more errors into the system. Error correction with voltage data for only two meters per transformer was attempted in this project. Transformers with fewer than two meters were listed in exception views, along with meters and transformers that had bad location data.

2.2.2 Software Requirements

The meter-to-transformer and phase identification solutions demonstrated are commercially available proprietary software, each with patents pending.

2.2.3 Supporting SDG&E Infrastructure and Data Requirements

Table 3 below compares data needed for the analysis and demonstration purposes, side-by-side with the data provided by SDG&E.

For the analysis purpose, the most important data is meter voltage interval data, which is essential for both phase identification and meter-to-transformer use cases. SDG&E provided two-year voltage data with 0.15 volts precision on five-minute intervals. For most of the meters in the sample, the voltage data covers the entire period. In cases where voltage data is not available, such as during an outage, or during the one hour lost because of the daylight-saving time change, the voltage data appears “frozen”. The system automatically interpolates the gap by constructing a linear line between the start and end of the period. When plotted, the interpolated gap period is shown as an artificial straight line, in the middle of curvy and random ups and downs, as if it is frozen. More details on the correction of the frozen periods are discussed in Section 2.3.

Metadata provides information on location, connectivity, and more. It first serves as a list of sample meters. For each feeder in the study, the metadata lists the meters under the feeder and limits the scope of analysis. SDG&E’s list is of high quality and very clean. SDG&E also added some “not real” meters into the study, which might mimic the potential of labeling meters under the wrong feeder. More details on excluding possible mislabeled meters are discussed in Section 2.3.

Metadata also provides latitude and longitude for each meter, transformer, and feeder. The information is important for meter-to-transformer and visualization purposes. SDG&E’s latitude and longitude data works for transformers but is not very accurate for the meters. For some meters, the latitude and longitude are the same as the linked transformers. For most of the meters, the problem is solved by converting meter addresses from metadata to GIS data. However, for a small proportion of meters, the latitude and longitude seem questionable. This is more critical in the meter-to-transformer use case and is discussed in Section 2.3.

Table 3. Compare Data Necessary and Data Provided

Purpose	Data Necessary	SDG&E Data Description	Data Quality
Analysis	One year AMI data that provides meter voltages at interval level	Two year five-min voltage data	Excellent
Analysis	Metadata showing which meters are under the experiment circuits	Metadata for the whole two circuits under study	Excellent
Analysis & Demo on Map	GIS data of each meter, and transformers	Latitude and Longitude for each meter and transformers	Good for transformers. Questionable for meters
Analysis & Demo on Map	GIS data of each meter, and transformers	Customer Information System (CIS) data that includes address for each meter	Good for meters

2.2.4 Updated Metrics

The primary metric for this demonstration was accuracy. The accuracy calculation assumed that field verification was a 100% accurate means of assessing meter-to-transformer and meter to phase connectivity. However, while analyzing the results it was discovered that field verification accuracies for both phase identification and meter-to-transformer were found at rates lower than 100%. Field verification accuracy could only be tested using GMSV on sections of the feeder with overhead wiring. This process was time consuming and so it was only completed thoroughly for the meter-to-transformer and phase identification examples where there was a discrepancy between the voltage correlation result and the field verification result. There were 35 cases where phase identification results from voltage correlation analysis disagreed with the field verification results and were available for analysis by GMSV due to the presence of overhead wiring. Thirty-four of these were on Feeder A and one was on Feeder B. In every instance, the field verification was incorrect, and the result from voltage correlation analysis was either correct, or likely but unverifiable. GMSV analysis suggested the utility field verification accuracy for transformer to phase connectivity was 95% on Feeder A. For meter-to-transformer a similar GMSV analysis was conducted and in several instances the findings of the field verification result were incorrect.

Because the field verification results could no longer be assumed 100% accurate, conclusions about accuracy were made using the following assumptions about ground truth:

1) In cases where the field verifications agreed with the voltage correlation analysis, the result was assumed correct.
2) In cases where the GMSV analysis was conducted and presented to the utility, the results from GMSV analysis were assumed correct.
3) In all other cases the utility field verifications were assumed correct only for the purposes of calculating a lower bound for the voltage correlation accuracy.

For this reason, the final accuracies for phase identification are presented as greater than 98% for Feeder A and greater than 97% for Feeder B.

2.2.5 Execution of Demonstrations

The demonstrations of phase identification and meter-to-transformer were carried out in accordance with the original schedule.

For phase identification, the solution was modified after the initial results came back to correct the assumption that each feeder had only three phases. The final result used the modified solution which assumed that both feeders had meters on all six phases.

For meter-to-transformer, the original solution was modified prior to providing initial results to give predictions in the case where there were two meters per transformer. The initial results from the meter-to-transformer were also accepted as the final result.

2.2.6 Use Case Execution

Phase Identification Use Case

The purpose of phase identification is to identify each meter's phase configuration. However, since the meter voltages cannot be compared to a known line voltage of each phase, a more accurate name for the algorithm is phase clustering. The algorithm clusters all the meters on a feeder into groups, and each group is labeled as a separate phase.

The clustering is based on voltage correlations. When electricity is consumed at some point on the grid, the voltage starts to fluctuate, and meters of the same phase move in similar direction and similar level, and therefore their voltage correlation is higher. Once voltage correlations are calculated, then the next task is to cluster the meters into their phases.

This solution begins the clustering process by finding "kernels" for different phases. Kernels are groups of meters that are strongly representative of each phase. When kernels are defined, the other meters' phases are identified by comparing the correlation with kernels. Agglomerative Hierarchical Clustering was selected to group the meters. There are many clustering algorithms readily available in many computer programming languages. Agglomerative Hierarchical Clustering Algorithm was selected because it provides a useful means for selecting kernels.

After an initial three kernels are constructed, a metric called the Hybrid Index is used to separate L-L meters and L-N meters. L-N phases are easier to distinguish than L-L because voltage differences are more pronounced between L-N phases. When there is a voltage change on phase A, both AB and AC are affected. The correlation's tendency is to squeeze together, and tangle with one another. One unique aspect of this solution is the separation of L-L meters and L-N meters, which makes it easier to cluster the L-L meters.

The last step in the phase identification solution used in this project was to iteratively identify kernels and rerun the correlations with those updated kernels as a starting point. With each iteration, the correlations become more accurate, and so are the kernels.

The algorithm is plotted in Figure 2 and Figure 3 below, where Figure 2 plots the steps for the analysis on a monthly basis, and Figure 3 begins with a summarization of all sample months and iterates using the summarization as a starting point.

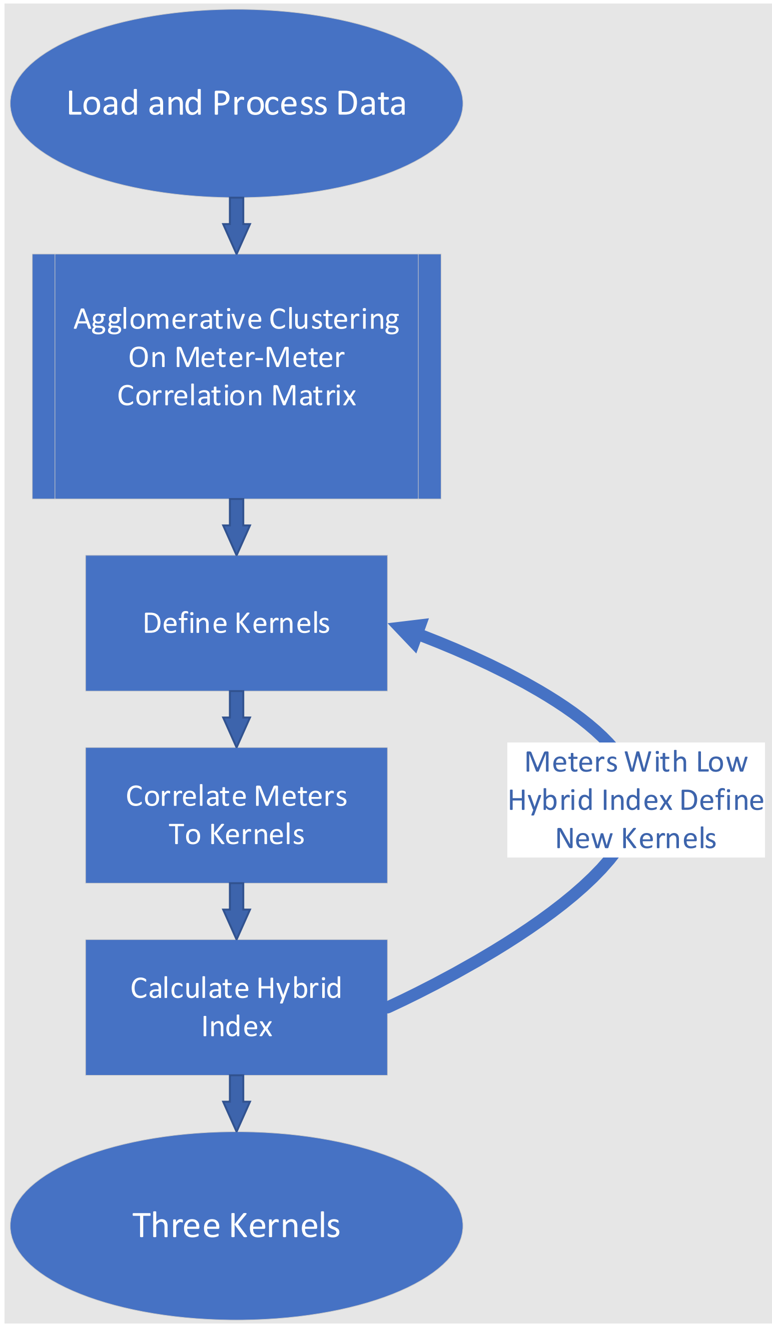

Figure 2. Phase Identification Algorithm – Step 1 Flow Chart

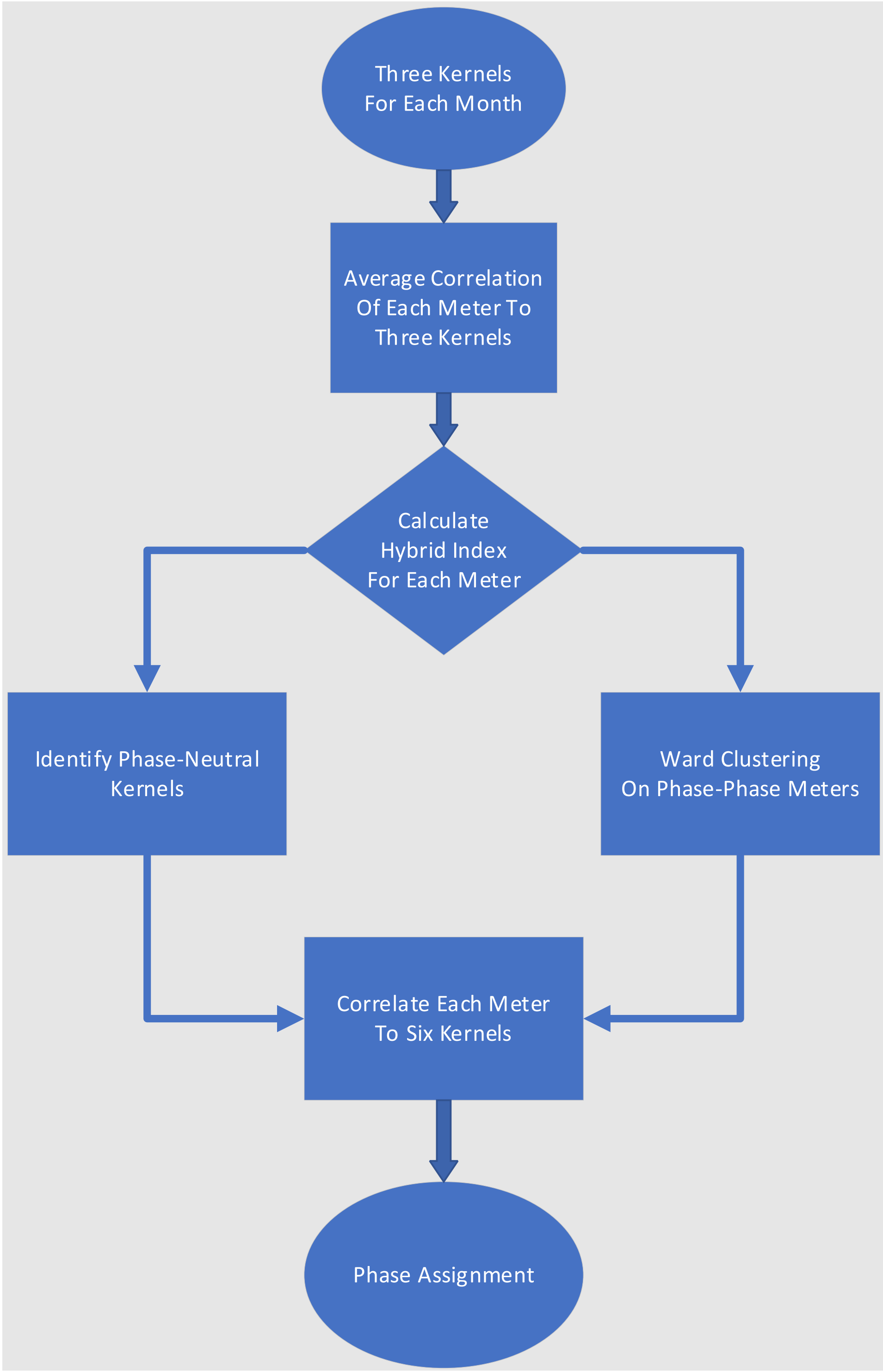

Figure 3. Phase Identification Algorithm – Step 2 Flow Chart

Meter-to-Transformer Use Case

The meter-to-transformer algorithm is performed meter by meter, transformer by transformer on the entire utility territory at once. The reason this does not lead to an extremely slow calculation is that the first step in the meter-to-transformer algorithm limits the number of potential transformers for each meter to the 15 closest ones. It also requires than any potential transformer is within 500 meters. These two numbers are default settings which can be adjustable by the utility if desired. For this demonstration the default values were used.

The second step in the solution is estimating a voltage-time series for each transformer. These estimates are created using the voltage readings for each connected meter in the existing connectivity model. If no existing connectivity model exists, an initial model is constructed by assigning each meter to the nearest transformer. For these reasons, accurate equipment location data is required. The algorithm assumes the model had greater than 50% accuracy, and that errors are uniformly distributed across the territory. In previous work, the vendor found that constructing an initial connectivity model by assigning each meter to the nearest transformer leads to accuracies of approximately 65%. For this project an initial connectivity model was provided with an estimated accuracy near 100%. Estimates for transformer voltages are made using a robust measure for central tendency, so that in the presence of errors on less than 50% of the connected meters, the estimate for transformer voltage is still appropriate. The robustness of the estimate breaks down completely with only two meters connected to the transformer from which to make the estimate. There is no measure of central tendency that is robust to errors when a dataset consists of only two datapoints.

The final step involves correlating the voltage time series of each meter to the estimated voltage of the nearest 15 transformers within 500 meters. The highest correlation between the voltage time series data for the meters and estimated voltage of the transformers is the basis for prediction of meter-to-transformer connectivity.

2.3 Data Analysis

2.3.1 Data Acquisition

As depicted in Figure 4. Data Transferring Timeline, the data transforming process had several issues, and thanks to a quick response from the SDG&E team, all issues were solved right away.

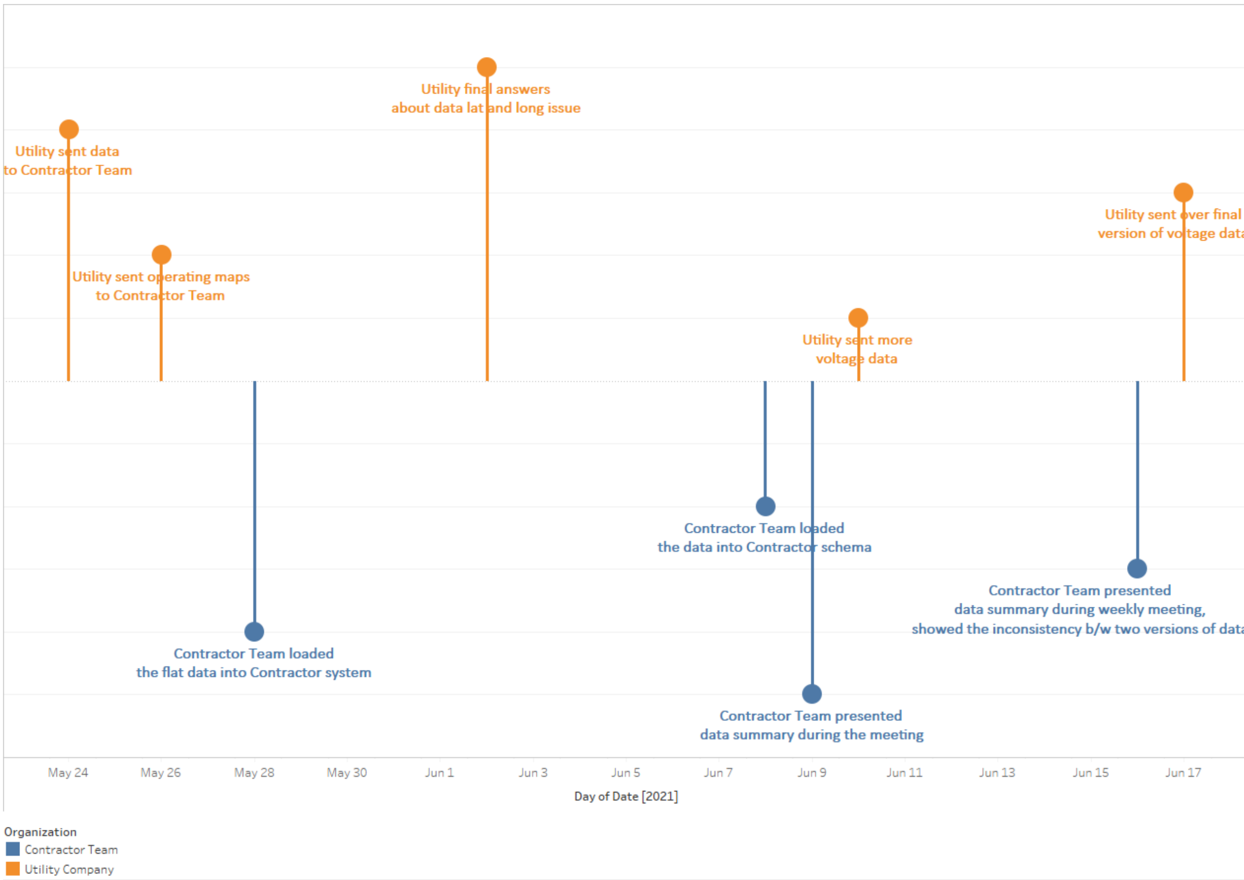

Figure 4. Data Transferring Timeline

The data from SDG&E includes:

- Bus voltage data. The bus voltage data contains the voltage level at the substation level, with irregular timestamp.
- Circuit data. The circuit data includes MW and MVAR readings at the circuit breaker, and the current reading by phase, with irregular timestamp.
- Switch SCADA devices. The switch data includes MW and MVAR at the switch level, along with current for three phases plus neutral phase, with irregular timestamp.
- Voltage at Remote Terminal Unit (VRTU) SCADA devices. VRTU data has voltage readings for each of the three phases, at the circuit level, with irregular timestamp.
- Tap position. This is the tap position data with irregular timestamp.
- Meter load data. Meter load data is the hourly kWh for each meter. It also provides tariff rate information.

- Transformer load data. Transformer load data is the hourly kWh consumption at the transformer level.
- Meter voltage data. Meter voltage data has five-minute voltage readings at the meter level, along with maximum voltage and minimum voltage across the five-minute interval.
- Metadata. Metadata is at the meter level, including:
  - GIS information, such as latitude, longitude, meter address, and zip code.
  - The transformer information that the meter is connected to, such as transformer ID, transformer latitude, transformer longitude, transformer KVA rating, and the circuit the transformer is connected to.
  - Meter connectivity date information, such as the date the meter was installed and removed.

The data needed in phase identification and meter-to-transformer algorithms are mainly in meter voltage data and metadata. Therefore, there was no need to clean up the duplication and missing data issues in the other data sources.

2.3.2 Introduction to the Two Feeders Under Study

For this analysis, SDG&E provided data for two feeders, A and B. Figure 5 and 6 below show maps of the two feeders. The red plus signs represent transformers, and the blue triangles represent meters. The size of the meters is proportional to the amount of data the meter has, which is a proxy of how much each meter contributes to the analysis.

SDG&E provided voltage data for only a subset of the meters. If a transformer has only one meter, the meter is selected; if a transformer has two or more meters, usually two meters are selected. For some larger transformers, where each links to 10, 20, or even more meters, it is also possible that three or four meters are selected. Out of the 974 transformers, 92 have more than two meters selected. The meters not selected are shown in the maps as small blue triangles. Concentrated small blue triangles indicate that area has many large transformers, each link to many meters, and a lot of the meters are not selected into this analysis.

The lines show which transformer connects to each meter. The very long lines that connect to off the chart points or across the whole map are due to bad latitude and longitude information.

Feeder A has 5,173 meters, much larger than B, but has only 325 transformers. On average, each transformer has 15.9 meters. The largest transformer is linked to 190 meters. In this area, phase balancing and meter-to-transformer accuracy are highly valuable. For example, if one transformer has 100 meters, and 10% of the connected customers have an EV, then when they all charge at a default charging time, the transformer will be under an extreme burden. Yet, with correct meter-to-transformer information the situation is avoidable by connecting EV rate meters to different transformers.

Feeder B has 649 transformers and 2,393 meters. On average, each transformer is linked to 3.7 meters. It can be seen from the map that the bigger transformers, where each linked to 10, 20, or up to 30 plus meters, are mostly concentrated at the southeast corner of the map. There are also some transformers at the top part of the map, or in the middle, that are linked to five to 10 meters. Most of the transformers that are spread out on the map are linked to less than five meters. There are 217 transformers that link to only one meter, and 143 to two. For this area, driving from one location to another takes longer, checking one location verifies just one or two meters, and most of the power lines in this feeder area are underground. For these reasons, it is costly to do a field check on the transformer phase and/or meter-to-transformer, and more costly to check for technical problems during an outage period.

2.3.3 Data Description, Data Cleaning, and Data Trimming

Partial Data

As mentioned above, while the metadata included the whole frame of the two feeders, meter voltage data was provided for only a proportion of the feeder.

As shown in Table 4, Feeder B has 649 transformers and 2,393 meters. On average, each transformer is linked to 3.7 meters. Figure 6 shows for Feeder B, most of the transformers that are spread out on the map are linked to less than five meters.

Out of these 2,393 meters, 12 meters are not included in the metadata table. Since five-minute voltage data is available for these 12 meters, covering all 731 days of the two-year study period, these 12 meters are included in the sample, and assigned to a virtual transformer. These 12 meters were included in phase identification analysis but excluded from meter-to-transformer because their latitude and longitude information were missing.

Table 4. Basic information for Feeders A and B

	A	B
# Meters	5,173	2,393
# Meters with Voltage Data	695	1,031
# Transformers	325	649
Avg # Meters per Transformer	15.9	3.7

Figure 5. Feeder A on Map

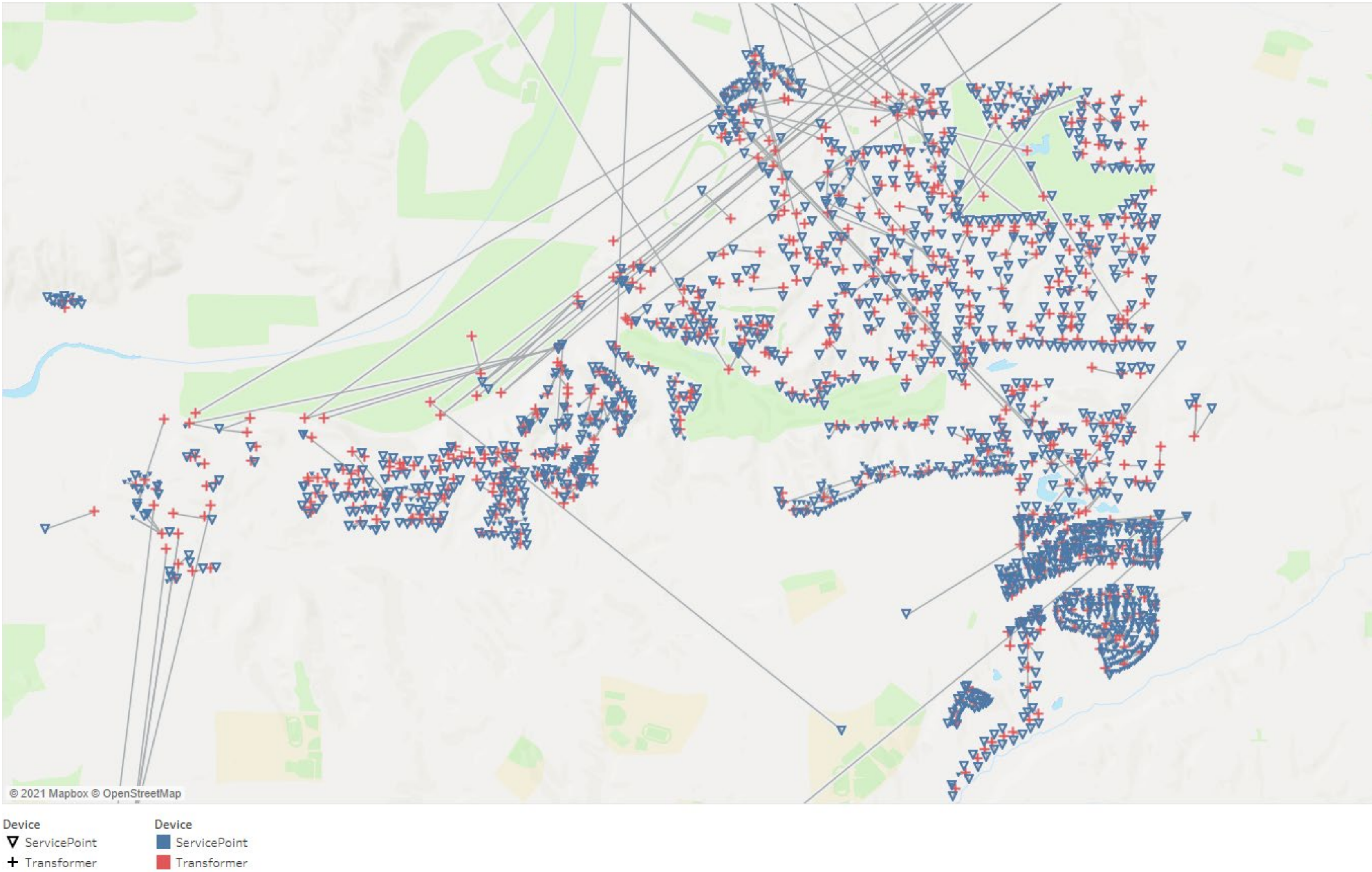

Figure 6. Feeder B on Map

Table 5 below lists detailed transformer distribution by size. More specifically, it shows the number of transformers by how many meters are linked to it. The 650th transformer, the virtual one, was excluded from this table along with the 12 meters "linked" to it. On column one, 217 transformers each link to only one meter, and 143 to two. That accounts for 55% of the transformers in Feeder B.

For this group of transformers, almost all meters linked to them were selected for the study, and five-minute meter level voltage data were available. The information is found in Table 6. Table 6 shows number of transformers by size in each row, and number of meters selected for the study for which voltage data is available in columns. The virtual transformer was excluded from this table. On Feeder B, for transformers with only one meter linked to them (as shown in row one), 209 out of the 217 transformers had one meter selected, for which voltage data was available. There were eight transformers, whose only meter was not selected, and hence was excluded from the analysis. Among the 143 transformers with two meters connected to them (row two in Table 6), there were 112 transformers for which all two meters were selected, 30 had one meter selected, and only one had zero meters selected. The larger transformers, with more than two meters linked to them, only had a proportion of meters selected. Out of the 289 transformers in this category, 222 had two meters selected into the study, or 77%; 46 transformers, or 16% had one meters selected, and 21, or 7% had more than two meters selected.

Due to the smaller transformer size in Feeder B, in terms of number of meters linked, a larger proportion of meters was selected into the study. Overall, 1,019 out of 2,381 meters were selected, which accounted for 43% of the meters in this feeder.

Table 5. Distribution of Transformer by Size

# Meters	Feeder A	Feeder B	Total
1	23	217	240
2	15	143	158
3	6	85	91
4	5	52	57
5	6	26	32
(5, 10)	56	80	136
(10, 20)	158	41	199
(20, 30)	26	3	29
30+	30	2	32
Total	**325**	**649**	**974**

Table 6. Feeder B: Number of Transformers by Size and # Meters with Voltage Data

# Meters	Zero	One	Two	Three	Four	Total
1	8	209	0	0	0	217
2	1	30	112	0	0	143
3	0	2	78	5	0	85
4	0	8	38	6	0	52
5	0	2	22	2	0	26
(5, 10)	0	19	59	2	0	80
(10, 200	0	12	23	3	3	41
(20, 30)	0	2	1	0	0	3
30+	0	1	1	0	0	2
Total	**9**	**285**	**334**	**18**	**3**	**649**

Feeder A was very different than Feeder B. As shown in Table 4, Feeder A had 5,173 meters, many more meters than Feeder B, but had only 325 transformers, just half as many as the number of transformers on Feeder B. On average, each transformer on Feeder A had 15.9 meters. The largest transformer was linked to 190 meters.

Like Feeder B, there were seven meters on Feeder A that were not in the metadata table and were combined onto a virtual transformer. Again, these seven meters were included in phase identification analysis, but excluded from meter-to-transformer, because their latitude and longitude information were missing.

Table 5 above lists the number of transformers by transformer size group. The virtual transformer was excluded from this table. Recall that more than half of the transformers on Feeder B had one to two meters. Here in Feeder A, however, the group with the highest number of transformers was 10 to 20. There were 158 transformers that were linked to 10 to 20 meters, accounting for 49% of the total number of transformers. Fifty-five, or 17% of the transformers, had less than or equal to five meters, compared to 81% in the case of Feeder B. Fifty-six transformers, another 17% of the total transformers were linked to 20 or more meters, compared to 7.1% for Feeder B.

Table 5 clearly shows that Feeder A ’s transformers were much larger in terms of the number of meters linked. Even though Feeder A had only one half as many transformers as Feeder B, it had more than two times as many meters compared to Feeder B. As shown in Table 6, for Feeder B, SDG&E tried to select two meters per transformer whenever possible, with slight adjustments here and there. Therefore, for Feeder A, the sample for analysis was expected to be smaller, in terms of absolute number of meters, and the proportion of the total meters.

Table 7 below is in the same format as Table 6. It shows the distribution of transformers by size, or how many meters linked, and number of meters selected into the analysis. On Feeder A, since most of the transformers had two meters or more, there were not as many transformers with only one meter selected. Most of the transformers, 214 out of 325, or 66%, had two meters selected into the analysis. Forty transformers each had only one meter selected, including 23 that were linked to just one meter. There were more transformers with more than two meters selected. Sixty-four had three meters, and seven had four meters, accounting for 22% of the transformers, much more than on Feeder B where only 21 had more than two meters selected.

Table 7. Feeder A: Number of Transformers by Size and # Meters with Voltage Data

# Meters	One	Two	Three	Four	Total
1	23	0	0	0	23
2	8	7	0	0	15
3	3	3	0	0	6
4	0	5	0	0	5
5	1	5	0	0	6
(5, 10)	0	42	14	0	56
(10, 20)	1	107	43	7	158
(20, 30)	2	20	4	0	26
30+	2	25	3	0	30
Total	**40**	**214**	**64**	**7**	**325**

Comparing the two feeders in the analysis, Feeder B had fewer meters, but more transformers, and more meters were included in the analysis. Such a sample design does not affect the phase identification much because phase configuration is mainly at the transformer level and since all transformers are covered, all phases have good representation in the sample.

For the meter-to-transformer task, however, the situation was different. On average, there were 2.1 meters on each transformer for Feeder A and 1.6 meters on each transformer for Feeder B. Chances are, some of the transformers' selected meters were not a very good representation for the transformer, which may have impacted the results. Also, the meter-to-transformer model uses the median of the meter's voltage as proxy for the transformer's voltage. With only one or two meters on each transformer, finding reasonable proxy was a challenge. Furthermore, the quality of geo information of the meters further complicated the situation.

The effect of sample design on the model performance is discussed in more detail when introducing the algorithm for each task.

Latitude and Longitude Coordinates

While latitude and longitude coordinates are not included in the phase identification algorithm, they are crucial for the meter-to-transformer model. To reduce the line loss from electricity transferring, and to reduce the length of service wire, a meter is always connected to the closest transformer whenever possible. When the length of the service wire from one meter to the closest transformer is not available, the geo distance based on latitude and longitude coordinates is used as a proxy. The statistics show that more than 50% of the time, a meter is connected to the transformer with the closest geo coordinates.

As mentioned previously, SDG&E's metadata uses transformers' latitude and longitude as geographic coordinates for the linked meters, which made it impossible to calculate the distance between meters and transformers. Addresses were converted from customer information addresses to latitude and longitude for each meter. Most of the meters had reasonable latitude and longitude coordinates after geo conversion with a few remaining suspicious.

To ensure the validity of the latitude and longitude coordinates, and avoid introducing unnecessary noise into the analysis, the meter-to-transformer analysis included only the meters whose geo coordinates were recognizable by Google Map. Table 8 below shows the number of meters with valid geo information by feeder. Overall, 400 meters' geo coordinates were not recognizable, and among the meters with voltage data, 161 meters were in this category. Hence, these meters were excluded from the meter-to-transformer analysis.

Table 8. Latitude and Longitude Validity

	A	B	Total
# Meters	5,173	2,393	7,566
# Meters with Geo Info	4,960	2,206	7,166
# Meters with Voltage Data	695	1,031	1,726
# Meters with Voltage Data and Geo Info	651	914	1,565

Study Period and Time Range of Data

For the selected meters in the two feeders under analysis, SDG&E provided five-minute interval voltage data that covered a two-years period, beginning October 21, 2018, to October 20, 2020. For more than 90% of the meters, the interval data covered 731 days of the study period. Table 9 below summarizes the number of meters by data completeness. Overall, 1,610 out of 1,726 meters had 731 days of data which is 93% of the sample.

Twelve meters have all data missing. This could be attributed to meter removal. Since this only accounts for less than 0.1% of the sample, no further investigation was warranted. Among the meters with only partial data available, most, or 76 of them, have roughly half a year of data. For all 76 meters, the data covers the last part of the analysis period. For 73 of the meters, the data ranges from April 23, 2020, to October 20, 2020. For the remaining three, the data begins in May or June, and all data ends on October 20, 2020. There are 60 meters on Feeder B and 16 meters on Feeder A.

The 10 meters with one to two years of data are on Feeder B. The data for these meters include random start and end dates with gaps for a few meters.

Eighteen meters have data gaps of less than one week. These meters were grouped as having complete data but are singled out to emphasize the fact that more than 93% of the meters have voltage data that perfectly covers the whole study period with no gap.

Table 9. Time Range of the Voltage Data

	A	B	Total
No Valid Data	1	11	12
Up to Half Year of Data	16	60	76
One to Two Years of Data	0	10	10
Up to One Week Gap	2	16	18
Whole Study Period	676	934	1,610
Total	**695**	**1,031**	**1,726**

Figure 7 below plots the number of meters changing over time. The upper section of the chart shows the number of meters on Feeder B, and the lower section shows the number of meters on Feeder A. The plot shows the same trend as described above where most of the meters have complete data across the whole period. The most obvious change occurred toward the last half of 2020 where seven, or 4.4% of the meters, were added into the sample. Since the plot for the number of transformers looked the same, the chart below is sufficient. Toward the last half of 2020, 4.2% of the transformers were added into the sample.

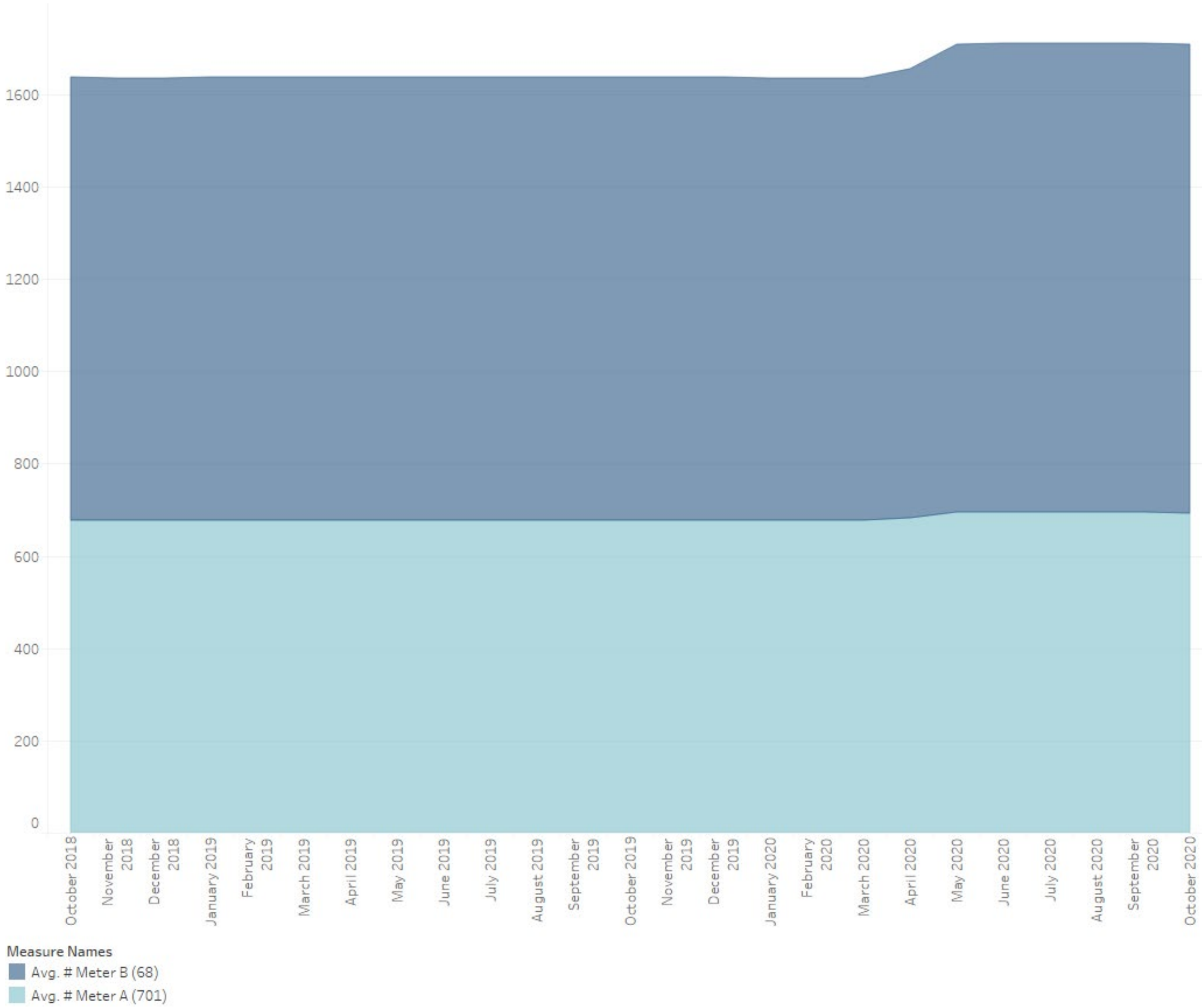

Figure 7. Number of Meters with Voltage Data by Time

Average Voltage and Data Interval

Figure 8 below shows the distribution of average voltage by meter. The chart on the top left is a traditional histogram plot of the 1,714 meters with any associated voltage data. Most of the meters are in the range of 240 volts, a small proportion of meters are in the range of 120 volts, and another small proportion of meters, 720 volts.

The overwhelming proportion of 240-volt meters skews the distribution of the other groups. Therefore, the same histogram is plotted using log form y-axis, to flatten the 240-volt group which is two to three magnitudes higher than the other groups.

Similar charts are plotted on the second row of Figure 8. It is clear in the bottom two charts that Feeder A and Feeder B both have a few meters in a voltage range that are unexpected.

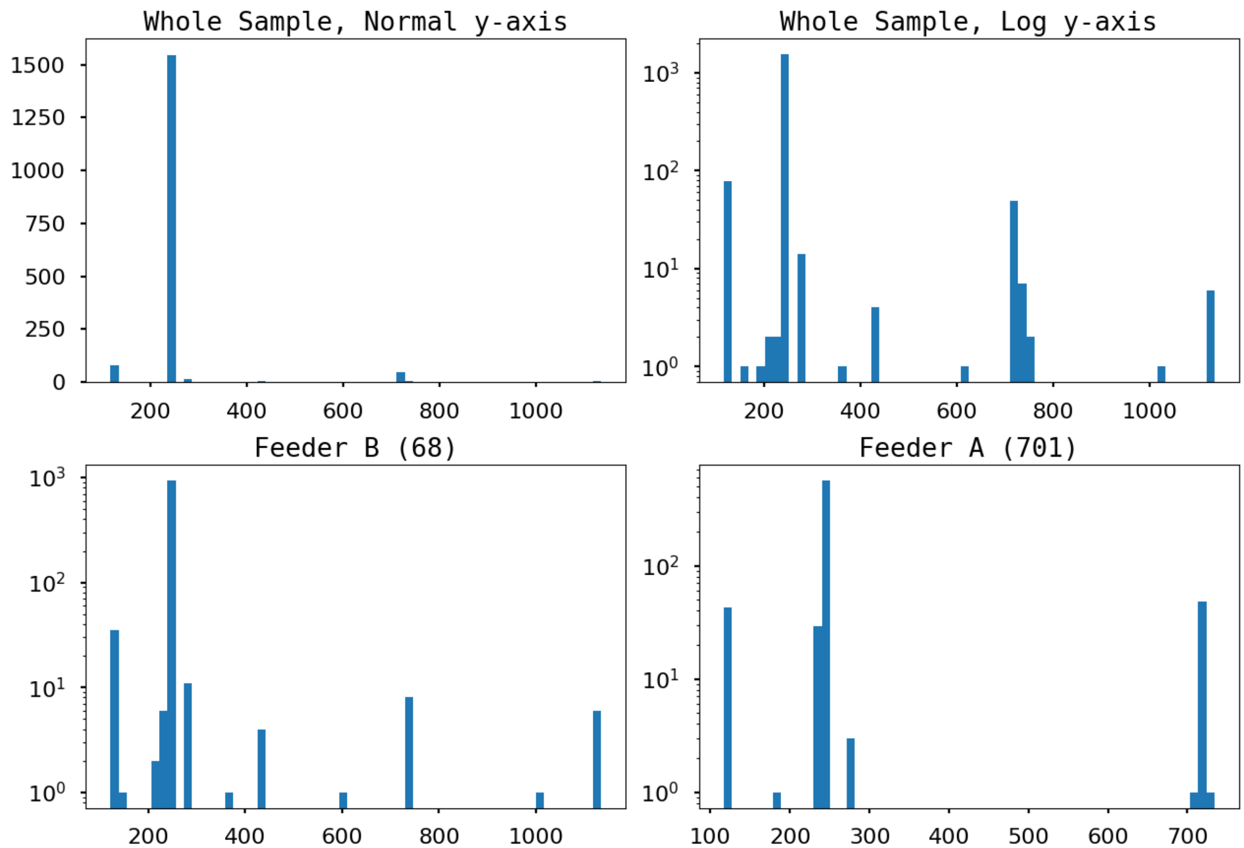

Figure 8. Average Voltage Histograms

It appears that the meters are sending data at different frequencies. For example, if a meter's data is not at five-minute intervals, but 15-minute instead, its interval voltage is then about three times the value of a five-minute interval meter. Therefore, if a meter's average hourly voltage should be 240 volts, with 15-minute interval data, the average can be 720 volts. In cases where a meter's data frequency changed in the middle of the study period, the observed average voltage is somewhere between 240 and 720 volts.

These meters were excluded from the analysis because they had voltages missing for most of the timestamps, making the correlation not comparable with the correlations calculated between two pairs of meters with complete data. Since the analysis was performed at a monthly level, if a meter changed data frequency during the early part of the analysis period, it might still be included in the analysis in the later part of the period.

Another possible explanation is when some meters' voltage dropped to zero at some point, due to a data issue. This was the case for one meter in the sample whose voltage was about 240 volts, until it dropped to zero on May 1, 2020. Therefore, this meter was excluded from the analysis after May 1, 2020, but was included in the analysis period prior to the voltage decline.

Table 10 below lists the distribution of meters by average voltage groups. Feeder A has 52 meters that will potentially be excluded from the analysis, and Feeder B has 24. Overall, 69 meters might be excluded, accounting for 4% of the meters where the voltage data is available.

Table 10. Distribution of Meters by Average Voltage Group

Avg Volt Group	A	B	Total
Below 120	1	0	1
120	42	35	77
120 to 240	1	3	4
240	597	950	1,547
277	3	11	14
277 to 720	0	6	6
720	50	8	58
Above 720	0	7	7
Total	**694**	**1,020**	**1,714**

Frozen Period

As mentioned in an earlier section, the voltage data may have some "frozen" periods, where the voltage is missing, but interpolated and represented as a linear line between the start and end points. Figure 9 and Figure 10 provide two examples of frozen periods. The first frozen period, as illustrated in Figure 9, starts on November 3, 2018, at 8:00 AM, and ends on November 4, 2018, at 7:55 AM (labeled using the gray vertical band). November 3, 2018, was the end of the daylight saving days in 2018. SDG&E stops reading voltage data during time changes; thus, the system draws a linear line between 241.49 volts, and 240.90 volts, the voltages at the two ends of the frozen period.

The upper portion of Figure 9 shows the voltage, with the lower portion showing delta voltage, or $\Delta Volt_t = Volt_t - Volt_{t-1}$. During the frozen period, voltage is plotted as a linear line. Hence, delta voltage appears to be a constant, and in this case $\Delta Volt = -0.001$.

These data points can adversely affect the correlation coefficient matrix. Consider the case where two meters are negatively correlated, and while one has voltage going up, the other's voltage is going down. One frozen period starts at the time where two meters' voltages are similar, even though one was in the middle of going up and the other going down; and ends at the time, coincidently, that the two meters' voltages are similar again. During the frozen period, the two meters' voltages appear to be similar, going in the same exact direction, and at the same exact level. Therefore, the correlation of the two meters is no longer negative, and in fact might increase significantly.

Of course, the frozen period may also cause the correlation between two meters to decrease. The effect is random, like noise in signals. Therefore, the data cleaning process is necessary to delete these periods, erase the noise, and emphasize the signals.

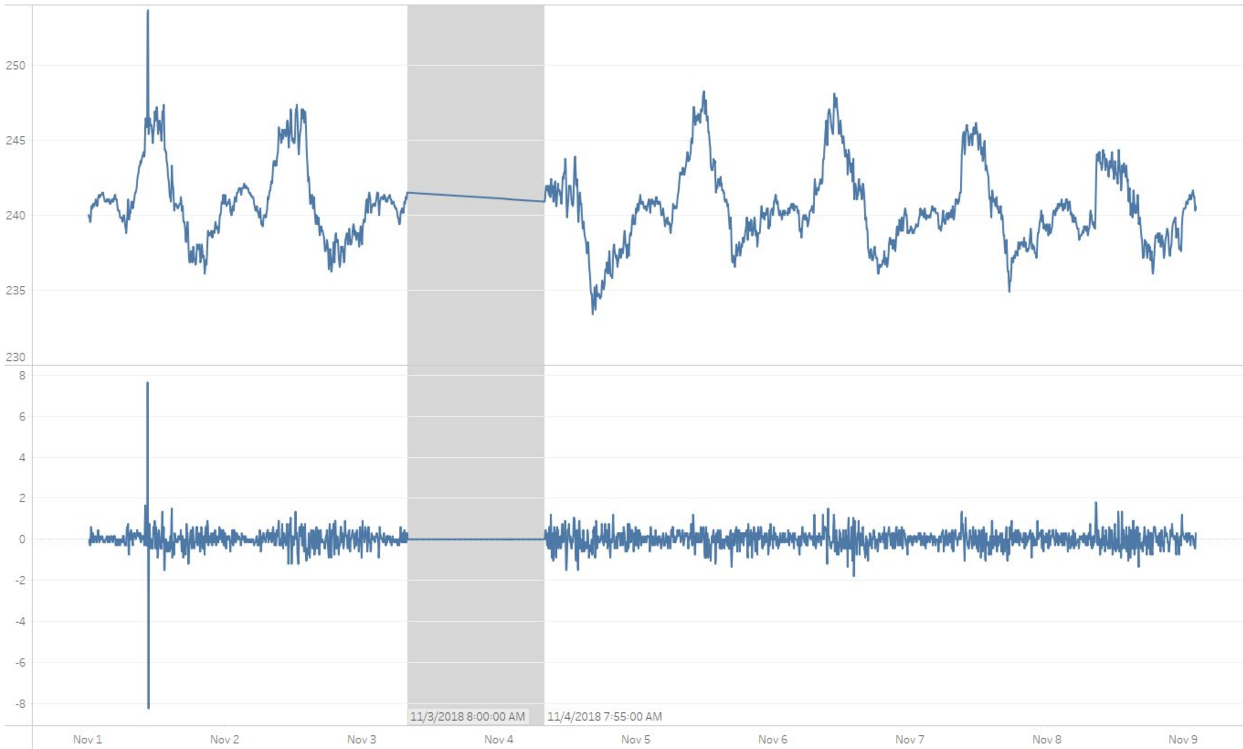

Figure 9. Frozen Example ONE

Figure 10 shows two frozen periods that are not due to a daylight-saving day time change. The time range for the frozen period on the left is from November 21, 2018, 8:00 AM to November 22, 2018, 7:55 AM. November 22, 2018, was Thanksgiving Day. This case serves as evidence that the frozen periods occur other than during daylight saving time changes.

The list below includes the dates with frozen data lasting longer than 24 hours:

- November 3 - 4, 2018 (daylight saving)
- November 21 - 22, 2018
- January 3 - 4, 2019
- January 18 - 19, 2019
- March 9 - 10, 2019 (daylight saving)
- November 2 - 3, 2019 (daylight saving)
- November 14 - 23, 2019
- March 7 - 8, 2020 (daylight saving)
- March 20 - 21, 2020
- March 27 - 28, 2020
- June 20 - 21, 2020
- July 10 - 11, 2020
- August 29 - 30, 2020

Figure 10 also shows another frozen period from November 23, 2018, 1:50 AM to 3:20 AM. The meter's voltage remains unchanged at 120 volts for one and a half hours. Examining if this is really a frozen period, the upper part of Figure 10 appears to have low resolution with voltage changes shown in steps rather than smooth lines. The lower part of Figure 10 confirms the voltage changes are in units of 0.15 volts, and $\Delta Volt$ takes the values of 0.15, 0.3 and 0.45, all multiples of 0.15.

This is common in utilities' voltage data. In some cases, there is data changing in one voltage unit. This will also introduce measurement errors into the analysis, and the measurement error appears as white noise too. Since there are many meters with data like this, the analysis will not keep the data as-is and will not tackle the issue with minor effects. If the voltage remains unchanged for a period longer than one hour, the problem is treated as a frozen period, and the data will be dropped. SDG&E provides two years of data, enough for the analysis, irrespective of some intermittent data points.

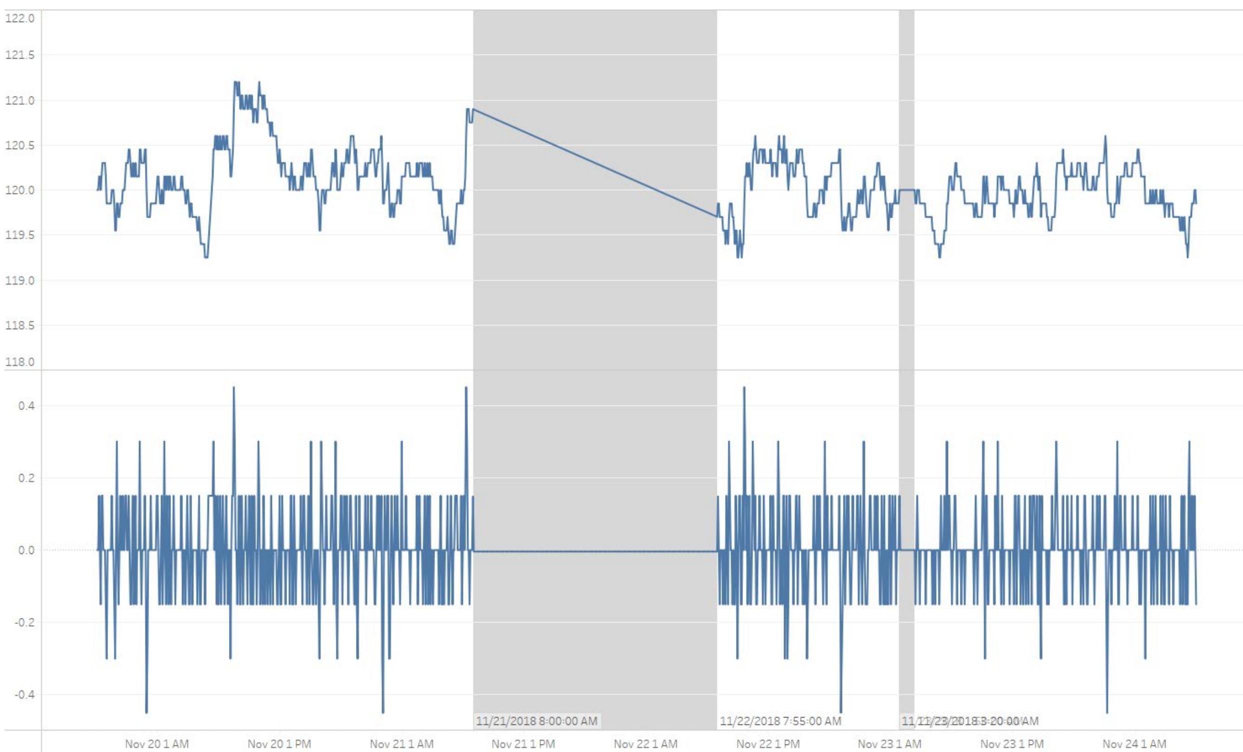

Figure 10. Frozen Example TWO

Figure 12 and Figure 11 below plot the data loss due to a frozen period, for Feeder A and Feeder B respectively. The top line, shown in aqua, is the number of meters in the raw data. This is calculated by taking the average number of meters with raw data for each interval to the monthly level, showing the same data as shown in Figure 7. The second line in green is the number of meters after excluding those with an abnormal voltage mean, as discussed previously.

The third line in red is the number of meters after deleting the frozen periods, where $\Delta Volt$ stays constant. The data volume dropped significantly in November 2018, January, March, and November of

2019, and again in March, June, July, and August of 2020. This aligns with the dates where frozen data lasts longer than 24 hours, as listed above. Overall, 3% of the data on Feeder A is dropped due to frozen period, and 4% for Feeder B.

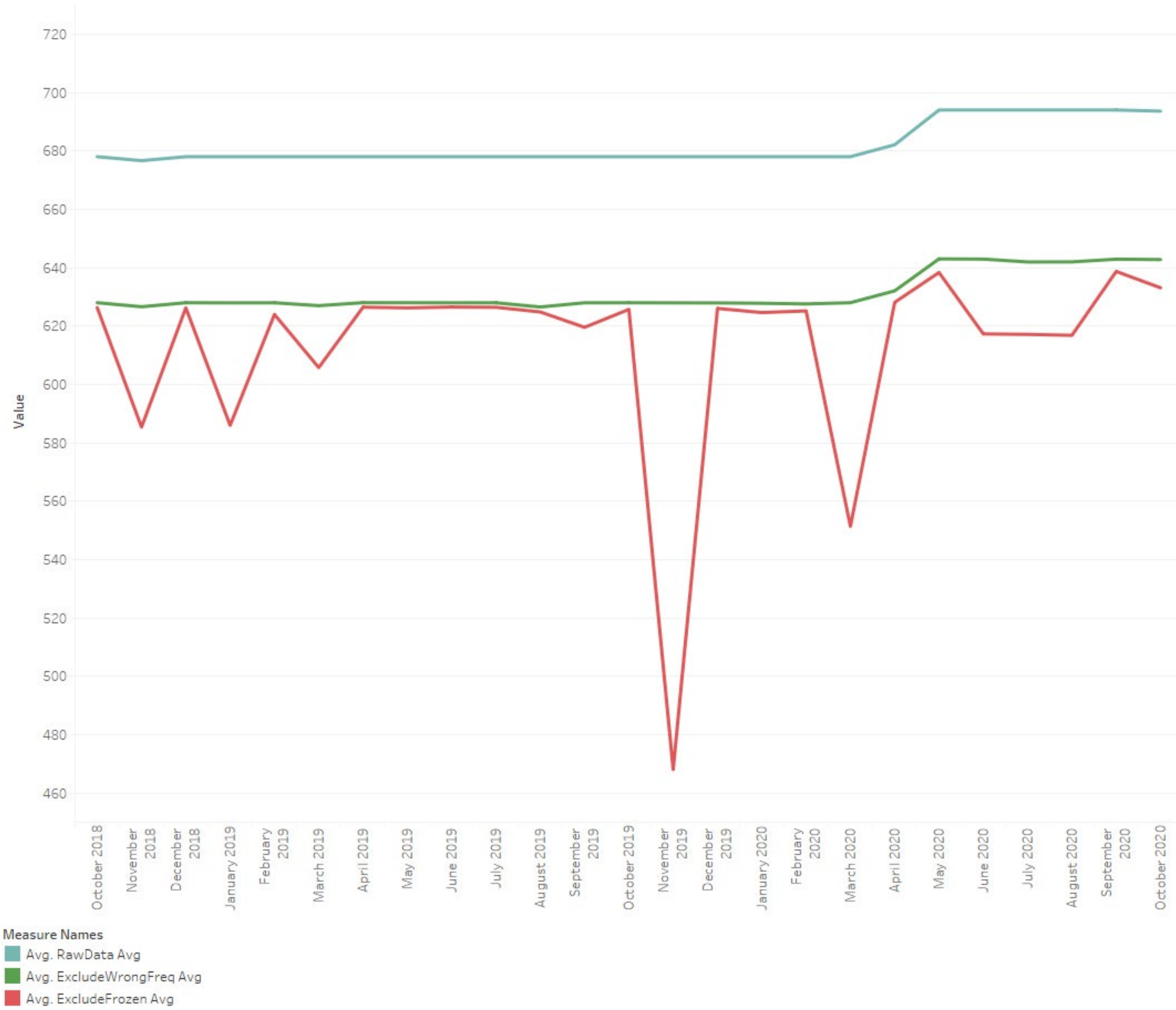

Figure 11. Time Series of Frozen Period – Feeder A

Figure 12. Time Series of Frozen Period – Feeder B

Jumps or Big Changes

Another data issue to consider is the jump on November 2, 2018, shown in Figure 12. Voltage volatility is usually caused by consumers' activities on the grid. When consumption goes up, voltage goes down, and vice versa. Meters on the same transformer tend to have voltages moving in the same direction, and with similar scale. Meters of the same phase tend to have similar voltage movements as well. This is fundamental to the phase identification and meter-to-transformer algorithm. Utility activities can have a larger impact on the voltage than consumption activities do. Utility activities usually impact the whole feeder, with some significant operations that cause significantly larger impact to voltage volatility than activities attributed to customer consumption. This may adversely affect the correlation coefficient matrix dramatically.

Figure 13 below shows three meters' voltage from August 19, 2019, to August 21, 2019. There are two big jumps during this period. In the morning of 19th, at 9:00 AM, the voltage jumped up, and at about

9:00 PM, the voltage jumped down. Without the jump, the correlation between the meter shown in red and the other two meters are very low, about 20%; but the jumps increase the correlation to a 40% level.

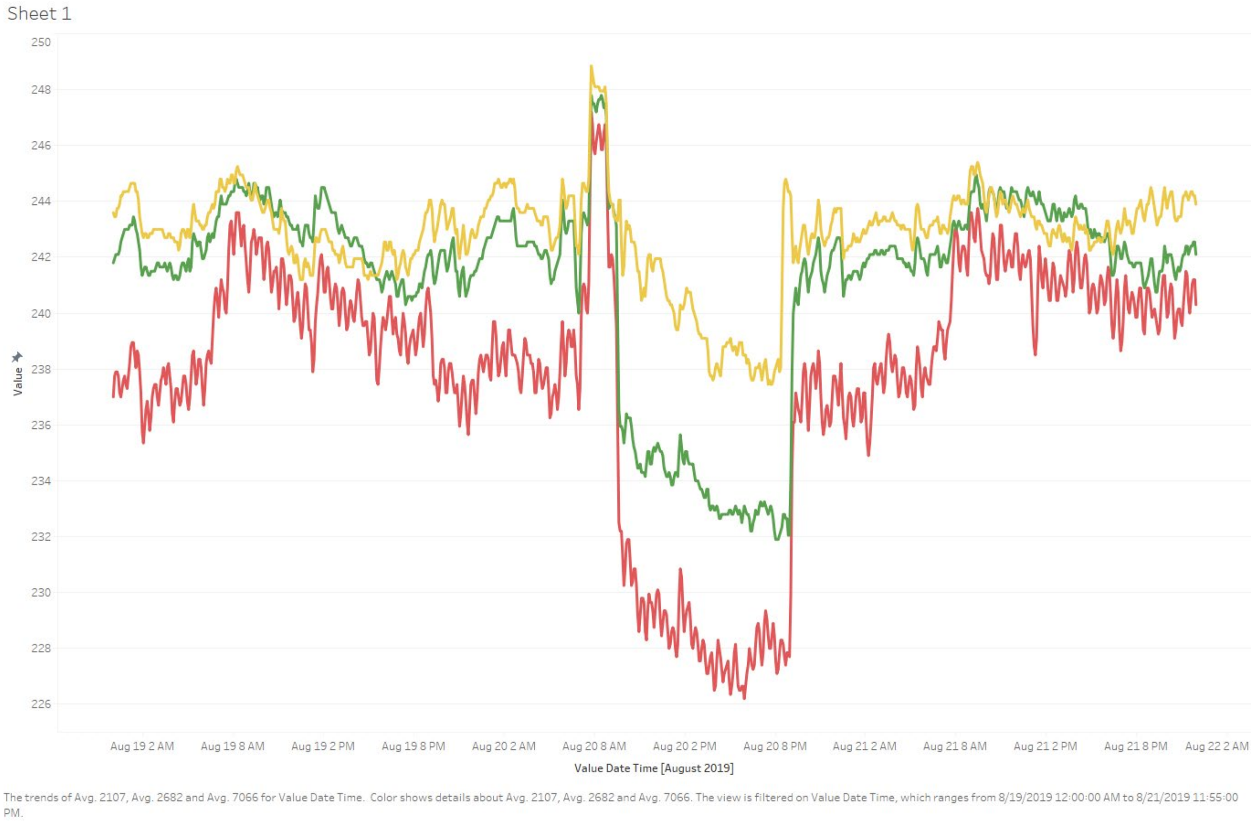

Figure 13. Example for Jumps

According to SDG&E, the utility's activities on the grid can change the voltages up to two or three times per day. There are 288 five-minute intervals each day. These activities can cause big jumps in up to 1% of the intervals. Therefore, the top one percentile jumps are dropped from the analysis. Such data cleaning steps are very likely to eliminate useful voltage volatility that is due to consumption activities, and hence cause loss of valuable information that contributes to the correlation among meters. Fortunately, due to SDG&E's abundant data sources, high quality data could be utilized for this analysis.

2.3.4 Data trimming

Phase Identification

Figure 14 and Figure 15 below plot the average amount of data for each sample month, by feeder, after each step of data trimming. From the raw data, the observations are excluded from the analysis because of the reasons listed below. Some of these data trimming steps drop intervals but not meters, some of the steps drop meters, and some do both.

If a meter loses some intervals, it may still have a prediction for the sample month. Even if the meter is dropped from the sample month, since the analysis is done monthly, it may still have results from the other months. These steps were used to cleanse/trim the data.

1) The meters have no valid interval voltage data. This step removes meters from all the sample months, and there is no prediction for these meters. The average number of meters is plotted in red for each sample month, in Figure 14 and Figure 15 for feeders A and B, respectively.
2) The records come in with wrong intervals, or the meter's average voltage is out of normal boundary. The "normal" boundary includes 1) 120 +/- 5%, 2) 240 +/- 5%, and 3) 277 +/- 5%. This step removes meters from sample months. The average number of meters is plotted in orange.
3) The records are from a period when voltage is frozen. This step drops intervals only. If a meter loses too many intervals, it may not have enough data, and hence is excluded from the sample month. The average number of meters is plotted in yellow.
4) The records have spikes that exceed the threshold, either up or down. This step drops intervals only. Again, if a meter loses too many intervals, it may get deleted from the sample month. The average number of meters is plotted in green.

For each sample month, the prediction is generated for all the meters that remain in the sample. The average number of meters is plotted in blue, which almost always coincides with the sample after Step 3, and thus the blue line is hidden behind the green line.

For both feeders, November 2019 is dropped from the analysis, mainly because the frozen period is too long, and hence none of the meters have enough data for the month. Again, thanks to the abundance of data provided by SDG&E, the analysis team can choose data quality over quantity and do not have to lower the criteria.

Figure 14. Data Trimming for Phase identification – Feeder A

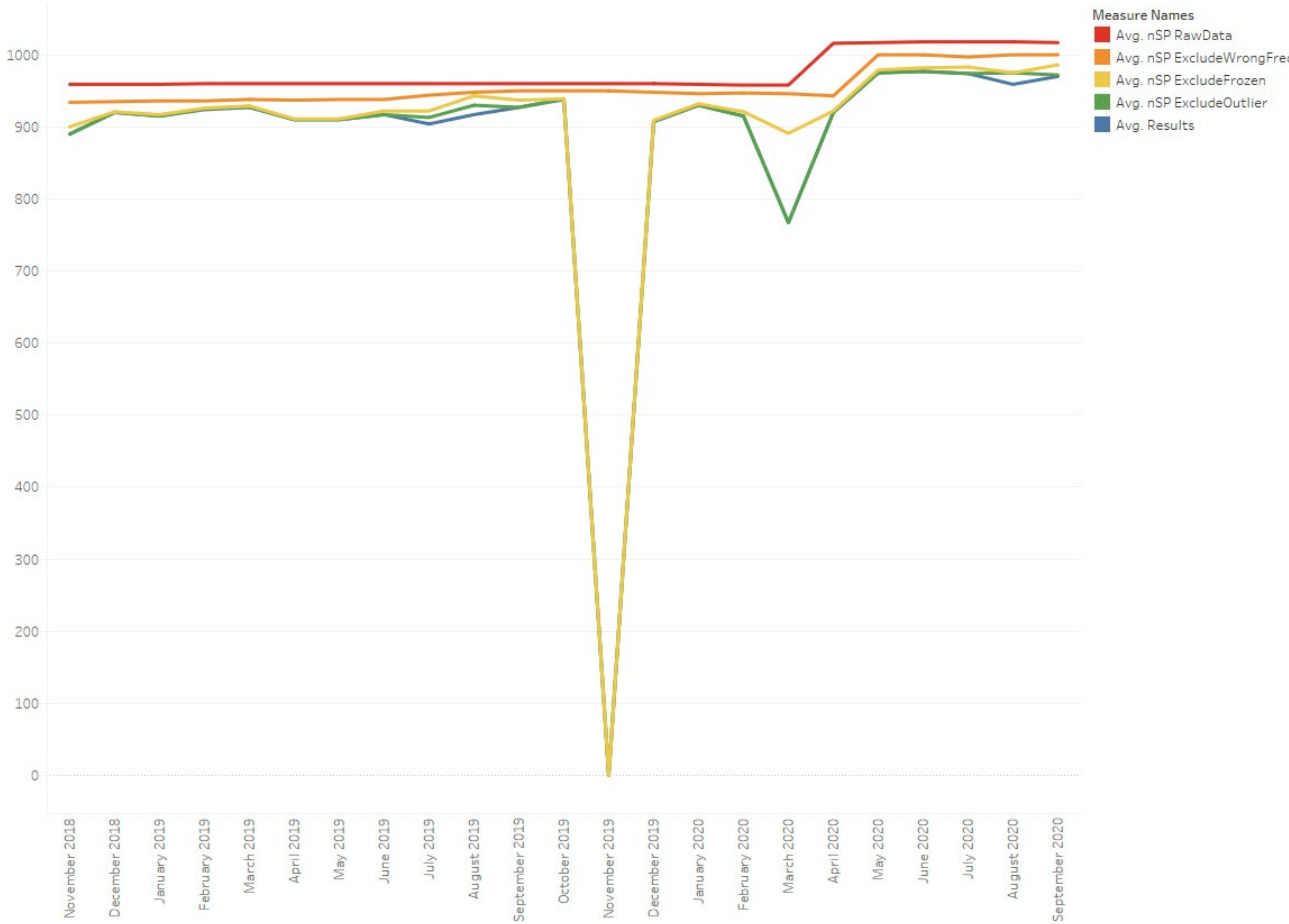

Figure 15. Data Trimming for Phase identification – Feeder B

Table 11 lists the average number of meters across all sample months after each step of trimming, along with the percentage drop compared to the raw data. The last row, "Monthly Results", contains the number of meters that have a prediction from each sample month. As explained above, one meter might be excluded from one month but still has predictions from other sample months. Therefore, the number of meters with any results is higher than the average sample size after some steps of data trimming. The last row of Table 11 shows that, on average, the sample months have results for 1,474 meters. However, the whole analysis yields predictions for 1,632 meters in total. The results are discussed in Section 3.1.

Table 11. Phase Identification Data Trimming

	A		B		Total	
	# Meters	% Decrease	# Meters	% Decrease	# Meters	% Decrease
Raw Data	682		975		1,657	
Exclude Wrong Freq	629	8%	955	2%	1,584	4%
Exclude Frozen Period	602	12%	894	8%	1,497	10%
Exclude Outliers	593	13%	885	9%	1,477	11%
Monthly Results	**591**	**13%**	**883**	**9%**	**1,474**	**11%**

Meter-to-Transformer

Figure 16 and Figure 17 below are similar charts to the phase identification charts, that plot time series of the number of meters after each step of data trimming. The legend follows a rainbow spectrum from red to purple and are plotted in the same order of data trimming steps. The last time series plotted in pink is the number of meters with a prediction from the analysis. The data trimming steps are listed in order below.

1. Exclude meters with no valid voltage data. The number of meters is plotted in red.
2. Exclude meters with no valid latitude or longitude coordinates. The number of meters is plotted in orange.
3. Exclude transformers with only one meter link to it. The number of meters is plotted in yellow.
4. Exclude meters whose voltages come in wrong intervals. The number of meters is plotted in green.
5. Exclude the records when voltage is frozen for a long period of time. The number of meters is plotted in aqua.
6. Exclude the records jumping up or down that exceeds threshold. The number of meters is plotted in blue.
7. At this step, check and make sure that all transformers have at least two meters with valid data. If not, drop the whole transformer. The number of meters is plotted in purple.
8. The number of meters for which the analysis provides a meter-to-transformer prediction. The number of meters is plotted in pink.

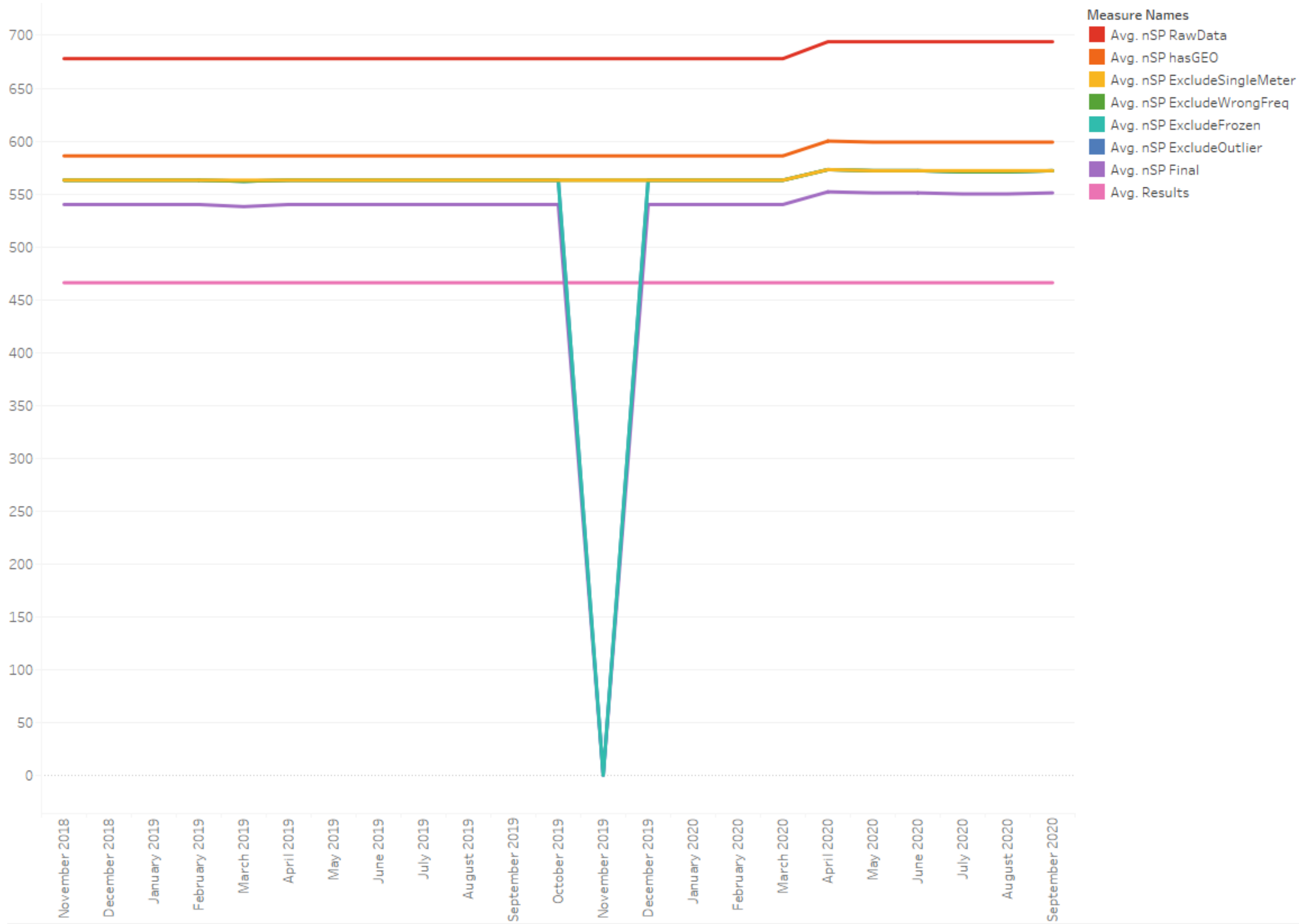

Figure 16. Data Trimming for meter-to-transformer – Feeder A

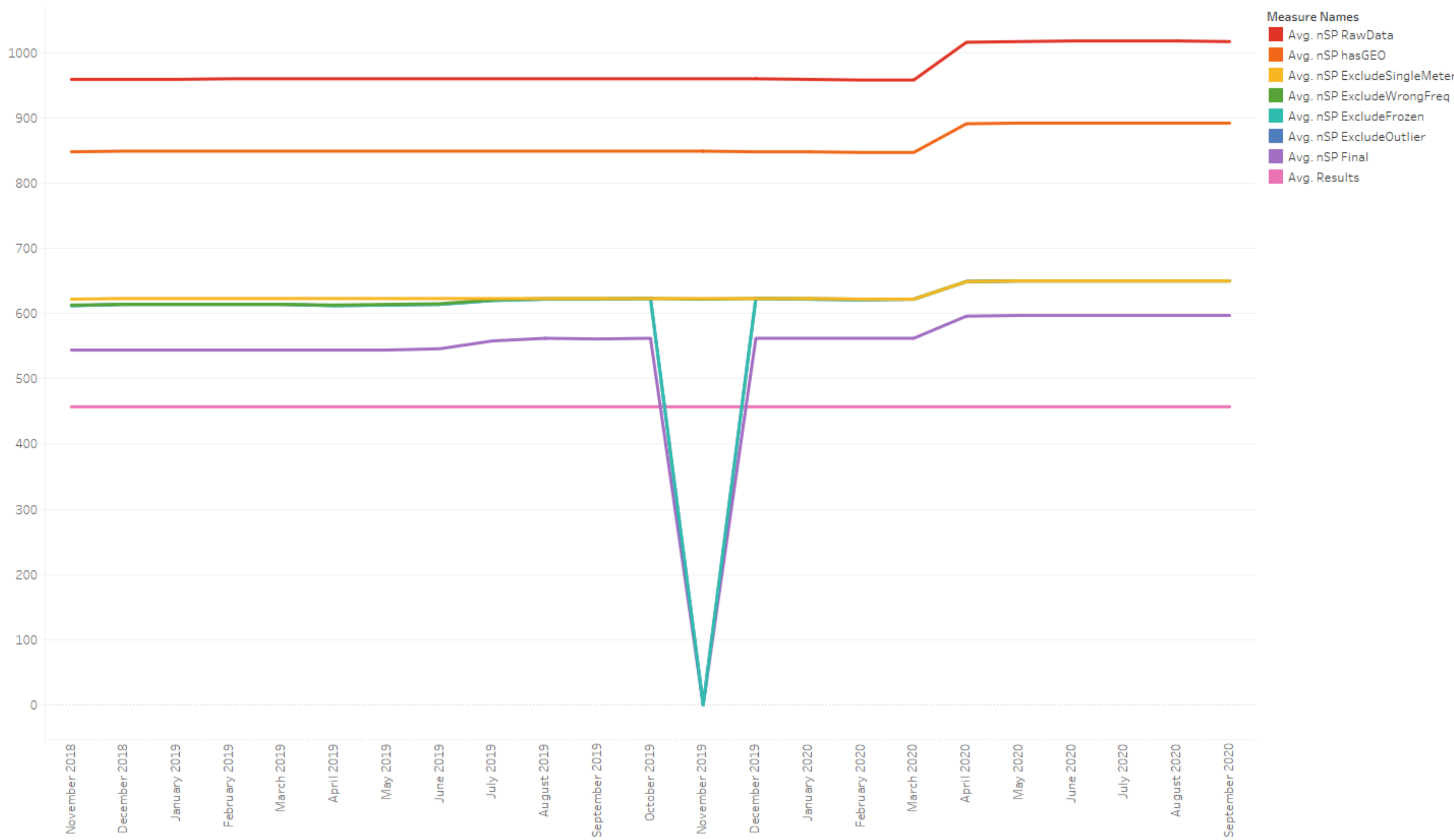

Figure 17. Data Trimming for meter-to-transformer – Feeder B

Similarly, as in Table 11, Table 12 lists the average number of meters across all sample months after each step of trimming for the meter-to-transformer analysis. Many more meters are dropped from the analysis, mainly because those meters are on transformers for which only one meter's voltage data is valid. When there is no information on transformer voltages, the meter-to-transformer algorithm uses all the other meters that are linked to the transformer as a proxy for the transformer. If the given meter is the only meter on a transformer, the algorithm is nonfunctional.

Also, the meter-to-transformer algorithm works better for transformers with more meters, and not as well for the transformer with only two meters. Imagine a transformer with only two meters, if one meter is wrong, the algorithm can determine if the two meters do not belong to the same transformer but cannot tell which meter is wrong and which is correct.

More discussion on how number of meters on a transformer affect the meter-to-transformer algorithm is provided in the execution of the meter-to-transformer use case described in Section 2.2.6.

Overall, the meter-to-transformer analysis provides a prediction for 923 meters, about 56% of the meters with voltage data.

Table 12. Meter-to-Transformer Data Trimming

	A		**B**		**Total**	
	# Meters	**% Decrease**	**# Meters**	**% Decrease**	**# Meters**	**% Decrease**
Raw Data	682		976		1,658	
Exclude Invalid GEO	590	14%	861	12%	1,450	13%
Exclude Single Meter	566	17%	630	35%	1,196	28%
Exclude Wrong Freq	565	17%	627	36%	1,192	28%
Exclude Frozen Period	542	21%	601	38%	1,143	31%
Exclude Outliers	542	21%	601	38%	1,143	31%
Final Sample	521	24%	542	44%	1,063	36%
Results	**466**	**32%**	**494**	**49%**	**960**	**42%**

3.0 Results

The purpose of this module was to apply the phase identification model and meter-to-transformer model on SDG&E's data and test the prediction accuracy. While the prediction accuracy was discussed thoroughly in the previous section, there are some additional metrics worth discussion.

3.1 Results Discussion

3.1.1 Phase Identification Prediction Accuracy

Given a model prediction, the next step required is the evaluation against the ground truth for verification of the accuracy scores. As the ground truth is not available, SDG&E's labels are used as a proxy initially. Table 13 and Table 14 below are the confusion matrices comparing SDG&E's labels and the model predictions, for Feeder A and B, respectively. The matching percentage, “% Match” in the tables is defined as the number of meters where model prediction matches SDG&E’s label over the number of meters where SDG&E’s label is available.

In the confusion matrices below, the row heads are SDG&E’s labels, and the column heads are model predicted phases. There are some meters labeled as “No Access”, “Undermined”, etc., in SDG&E’s metadata. Those meters are combined as “No Info” in the table and are hence excluded when calculating matching percentages. There are some meters labeled as “ABC” and are also excluded from the “% Match” calculation.

The bold numbers on the diagonal of each matrix are the number of meters where model prediction matches SDG&E’s labels, and the off-diagonal numbers are unmatched meters. The “% Match” column provides the percentage of matched meters over total meters for a given SDG&E phase group. The number at the most bottom right of each table, is the overall matching rate for the feeder.

For Feeder A, most of the meters are configured as L-L. While the overall matching rate is 92%, the matching rate for the 264 L-N meters is 96.4%, and for the 312 L-L meters, the rate is 88.1%.

Table 13. Confusion Matrix – Feeder A

	A	B	C	AB	BC	AC	Total	% Match
A	**64**		1				**65**	**98%**
B		**98**	2		2		**102**	**96%**
C	1	2	**93**	1			**97**	**96%**
AB				**67**	1	13	**81**	**83%**
BC			1	1	**137**	1	**140**	**98%**
AC		1		17	2	**71**	**91**	**78%**
ABC		1	1	25	10	5	**42**	
No Info	2		6	2	1	8	**19**	
Total	**67**	**102**	**104**	**113**	**153**	**98**	**637**	**92%**

For Feeder B, the matching rate is 97%, with 831 matched meters, and 29 unmatched cases. On Feeder B, most of the meters are configured as L-N, and among the 832 L-N phase meters, the matching rate is 96.63%, and for L-L, 96.59%, not much difference.

Table 14. Confusion Matrix – Feeder B

	A	B	C	AB	BC	AC	Total	% Match
A	259	1	1		1	6	268	97%
B	8	296	4		2	2	312	95%
C	1	2	249				252	99%
AB				16	1		17	94%
BC					1		1	100%
AC						10	10	100%
ABC		1		7	16	22	46	
No Info	24	30	18	1	1	15	89	
Total	292	330	272	24	22	55	995	97%

The two 90%+ matching rates prove the model performs well and confirms SDG&E's records are of high quality. When the two sets of records agree with each other, correct meter labeling potential increases significantly. On the other hand, when the two sets of records do not agree with each other, it might be due to wrong prediction from the model *or* to an error in SDG&E's records.

There are 75 meters for which the model prediction does not agree with SDG&E's records, 46 on Feeder A, and 29 on Feeder B. For 72 out of these 75 meters, the model has very consistent prediction across all sample months available. Using GMSV, a virtual field verification was performed for these 72 meters to sort out the phase from overhead power lines wherever possible.

Feeder A has more than half of the meters on overhead powerlines, while the meters on Feeder B are mostly underground. Therefore, the virtual field verification applied mainly to Feeder A. There is only one meter on Feeder B that was checked on GMSV. Out of the 72 meters on which the virtual field verification is attempted, GMSV gave conclusive results for 35 of them and among these 35 meters, the model predictions are correct. That is, the field verification results were incorrect. Therefore, if assuming the model prediction is wrong for all the other 40 meters, when comparing to this version of ground truth, the model accuracy rate for Feeder A increases to 98%, and for Feeder B, the rate does not change much, remaining at 97%.

Figure 18 and Figure 19 below highlight the meters where virtual field verification succeeded on Feeder A and Feeder B, respectively.

Feeder A has many meters on overhead powerline, and hence many opportunities to do virtual field verification. On the map below, five groups of meters are circled and labeled from upper left to lower right, as group two to six.

For the following description, fictitious street names are substituted to preserve anonymity.

For Group 2, there are five meters; the transformers for these meters are traced from Elm St. to Oak Rd, where another transformer is connected to the same lines. Both the model prediction and SDG&E label agree that the transformer on Oak Rd. is Phase AB, and hence Group 2 should be the same.

Group 3 has 21 meters. The information needed to prove the phase for these meters is deducted from the meters whose phases are proven true, as shown below.

- The transformer on Fir Dr. to the North of Fir Dr. – Birch Ave. connection is proven as AC.
  - The transformers on Birch Ave. between Pine Road and Fir Dr. are of the same phase, AC.
  - Transformers on Willow Place are of a different phase, and hence are not AC.
- The transformers on Ash Dr. to the SE of Ash Dr. – Willow Place connection are proven AB.
  - The transformers on Cedar Dr. are different than the transformers on Ash Dr., and hence are not AB.

The other groups are all deducted following similar logic.

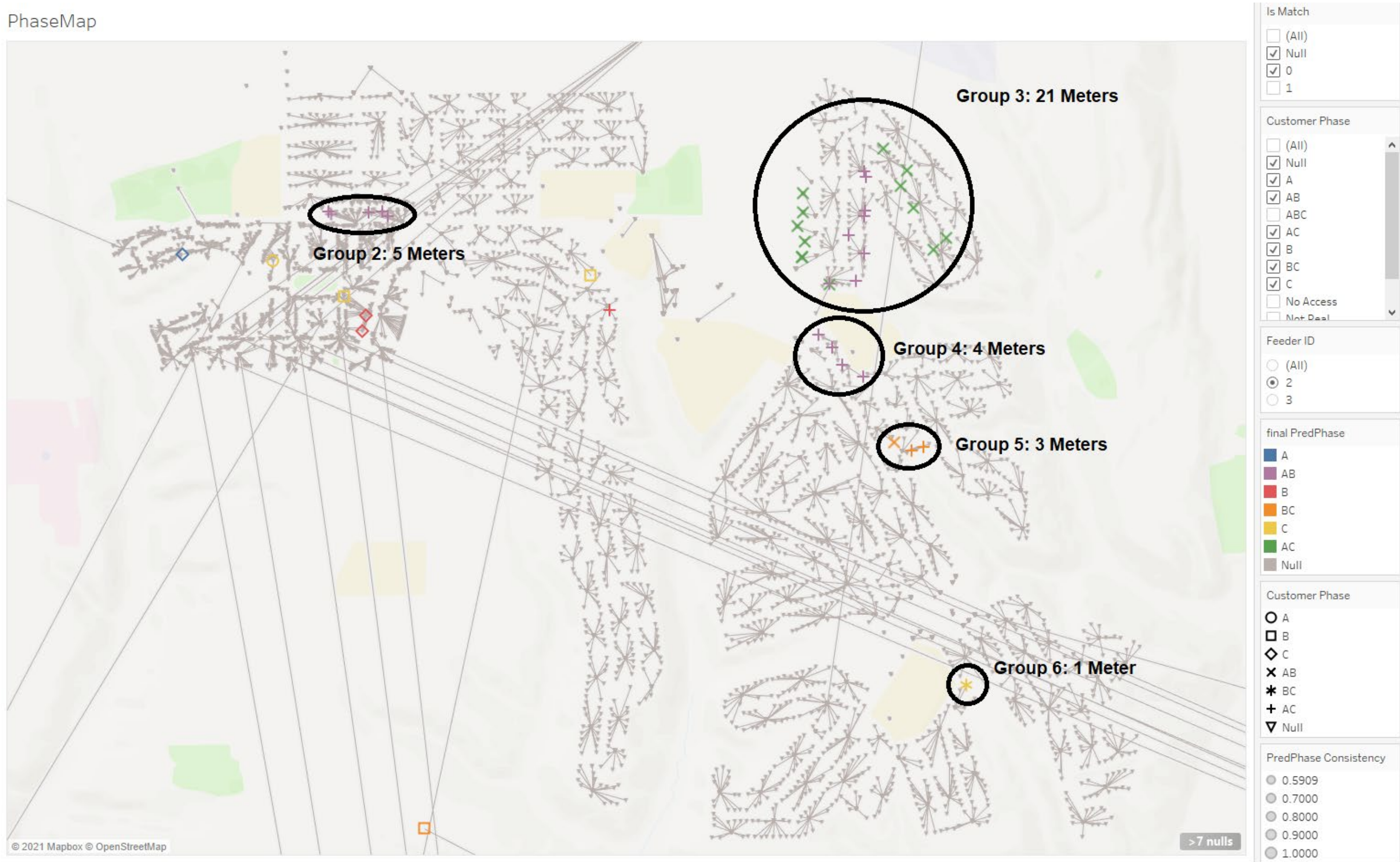

Figure 18. Virtual Field Verification on Feeder A

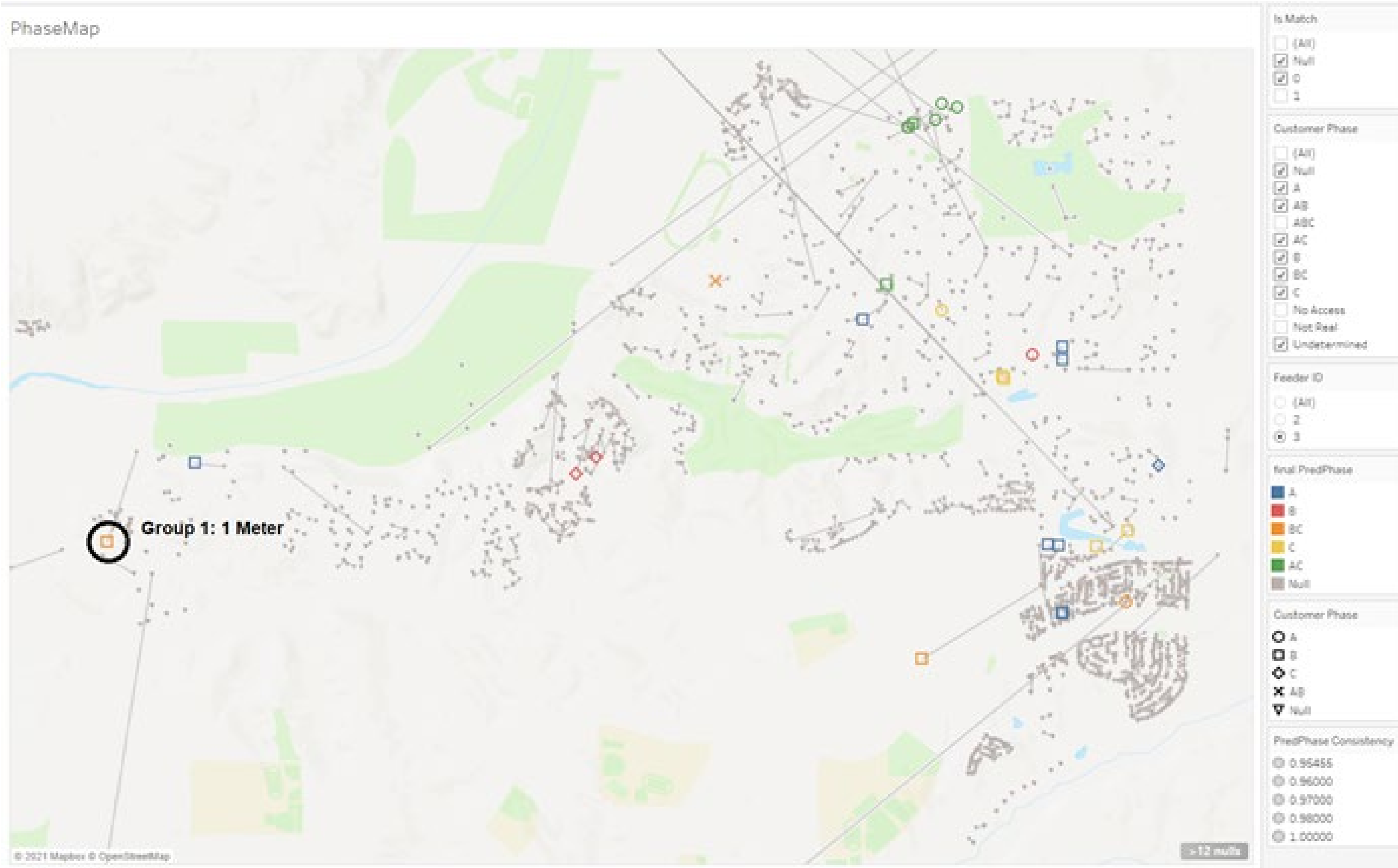

Figure 19. Virtual Field Verification on Feeder B

For Feeder B, the meter is on the left of the map. As shown in the legend on the right-hand side, SDG&E labels it with a square, or Phase B, but the model predicts it as orange, Phase BC. From GMSV, the meter should be L-L, not L-N. Figure 20 below illustrates the map of unmatched meters for Feeder B.

After virtual field verification, the number of unmatched meters decreases to 40, and the accuracy rates improve to 97% and 98%. The two figures below, Figure 21, and Figure 22 show these 40 meters on the map. The intention of these maps is to provide a direct and intuitive view of the model prediction, emphasizing where the model prediction does not match this version of ground truth.

In both figures, the shape of the icons is defined by ground truth. Three closed shapes, circle, square, and diamond, represent the three L-N phases, A, B, and C, respectively. Three radiant shapes include a plus sign, multiplication sign, and a star. These represent the three L-L phases, AB, AC, and BC. Phase ABC is represented with triangles, and the meters with no information are plotted as upside-down triangles.

The icon color is defined by the model prediction. Phase A, B, and C use three primary colors blue, red and yellow; and phase AB, AC, and BC use purple, green, and orange. If the prediction does not match the ground truth, the meter is emphasized with a bigger icon.

On Feeder A, there are several unmatched meters on the outskirts of the map, and hence two maps are included. The first one shows the whole picture, especially the unmatched meters that are scattered outside of the sizable cluster of meters. The second one zooms in and shows unmatched meters at the center of this feeder.

On the map, it seems many unmatched meters appear as small blocks. In fact, 34 out of these 40 meters are linked to a transformer for which two meters' voltage data is provided for the analysis. Eighteen meters, or nine pairs, have the phase prediction of one meter in agreement with the other meter on the same transformer, and both different than ground truth. Such a "coincidence" adds more confidence to the model.

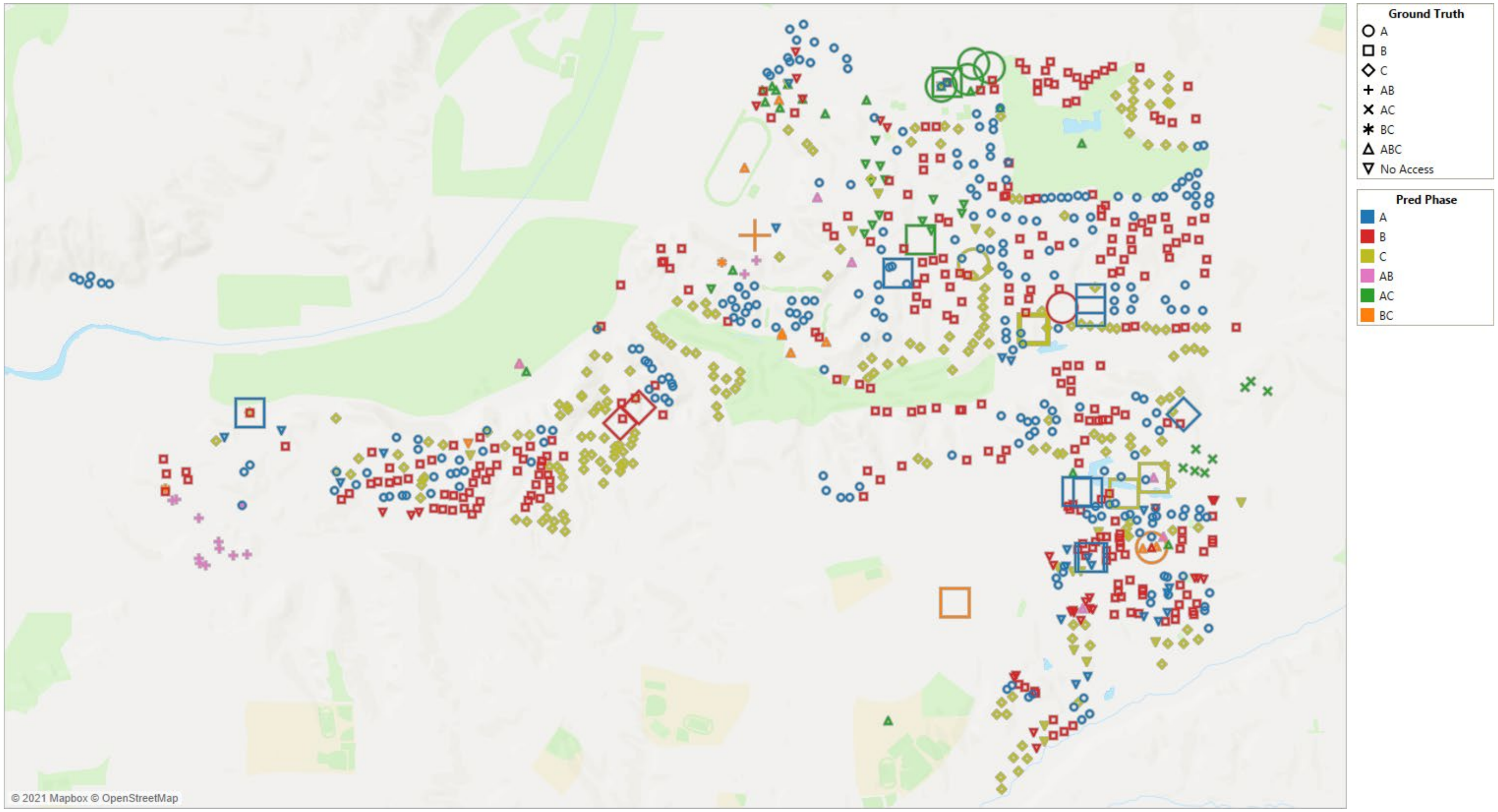

Figure 20. Map for Unmatched Meters - Feeder B

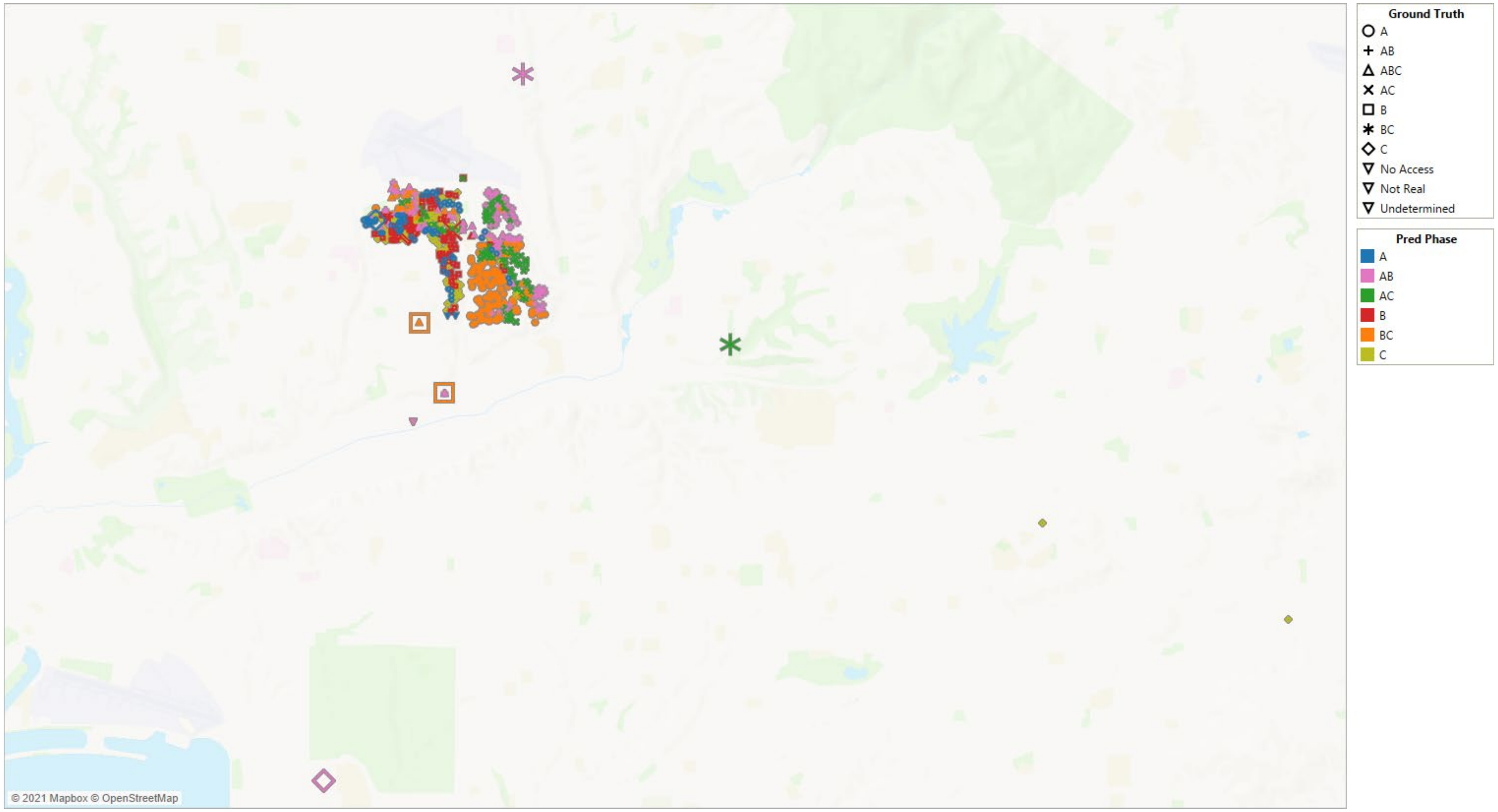

Figure 21. Map for Unmatched Meters - Feeder A Broad View

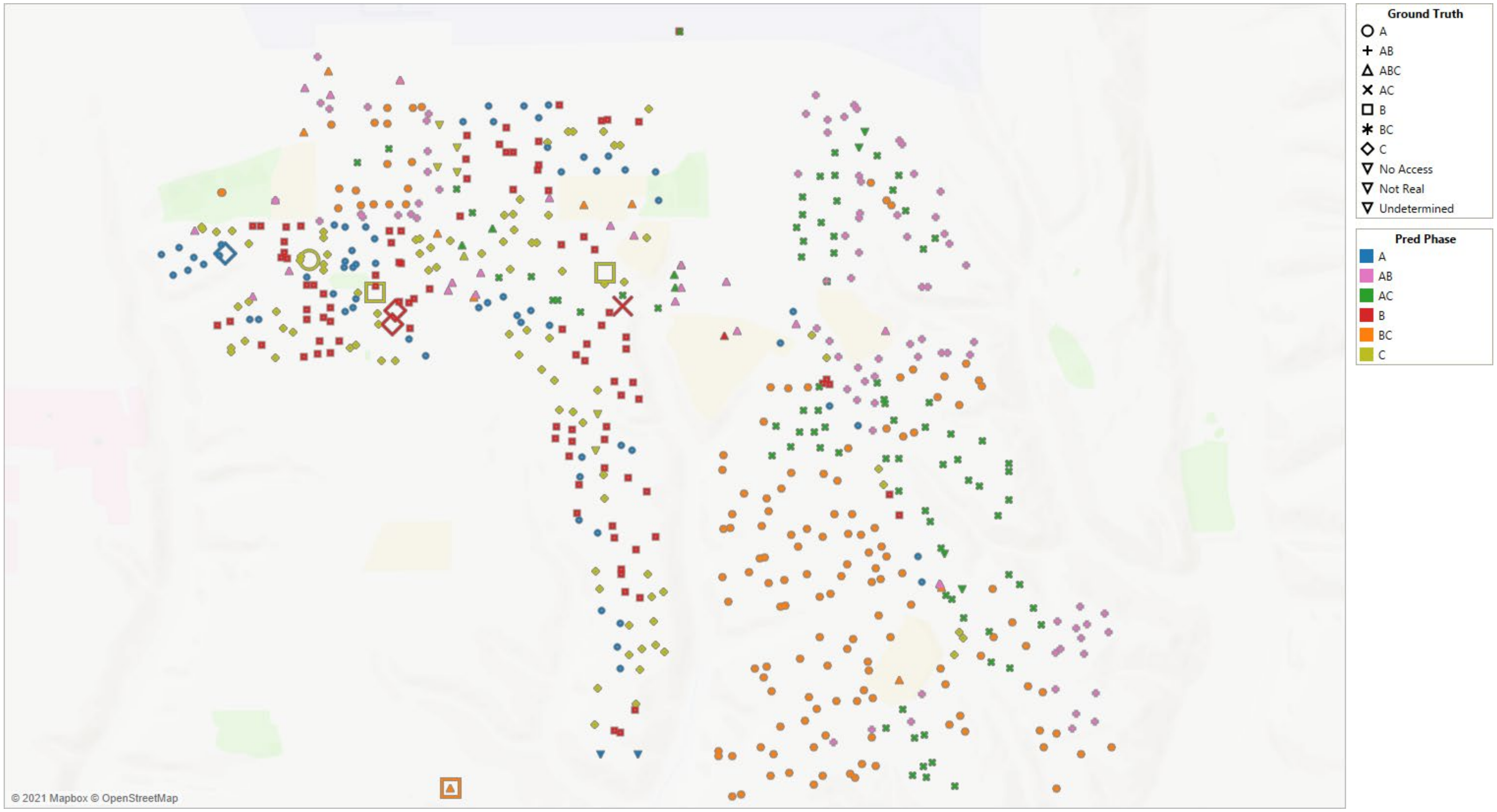

Figure 22. Map for Unmatched Meters - Feeder A Focus View

The other way to view these unmatched meters is through observation of where they reside within each of the clusters. The clusters are constructed using correlations with each kernel. Figure 23 and Figure 24 below project each meter's correlations with three L-N kernels onto a two-dimensional plane showing the correlation-location of the meters in clusters. Since these two plots are projections from a three-dimensional image, the x-axis scale and y-axis scale are not meaningful. They can be labeled as 0.5, 5, or 50, without any genuine change.

Again, in these two figures, shapes are defined by ground truth, colors are defined by model prediction, and size emphasizes if the prediction does not match ground truth.

Most meters' prediction matches the ground truth, and the figures have blue (prediction = "A") circle (ground truth = "A"), red (prediction = "B") square (ground truth = "B"), etc., but there are also some bigger icons.

For example, on Feeder B, Figure 24, there are many blue squares, green circles, red diamonds, and yellow squares. These meters, however, are located at the center or close to the center of each cluster. Take the blue squares as an example, it is more likely that they are in a blue circle cluster than in a red square cluster. The big orange square in the middle of Figure 24 is problematic. In fact, some sample months predict it as "AC", but more than 90% of the sample months yield prediction of "BC" as plotted in the figure. Figure 23 also shows several problematic examples on Feeder A. There is an orange square, a purple diamond, and a purple star in the middle of the plot. It seems the orange square has a higher possibility to be in an orange star cluster than in a red square cluster. Similarly, so is the purple diamond. It is far from the yellow diamond cluster at the bottom. The purple star, on the other hand, is not far from the orange star cluster, and close to the purple plus sign cluster. In fact, the prediction for this meter is not conclusive at all. About 60% of the sample months predict this meter as "AB", but the other 40% of the sample months do not agree. This meter is the purple star located on top of Figure 21, which seems to have bad latitude and longitude information, and therefore is not suitable for virtual field verification.

If the model is successful, excluding the meters located at the center of each figure, the other meters are much more likely to be in the predicted phase, as they are located closer to the center of the predicted clusters.

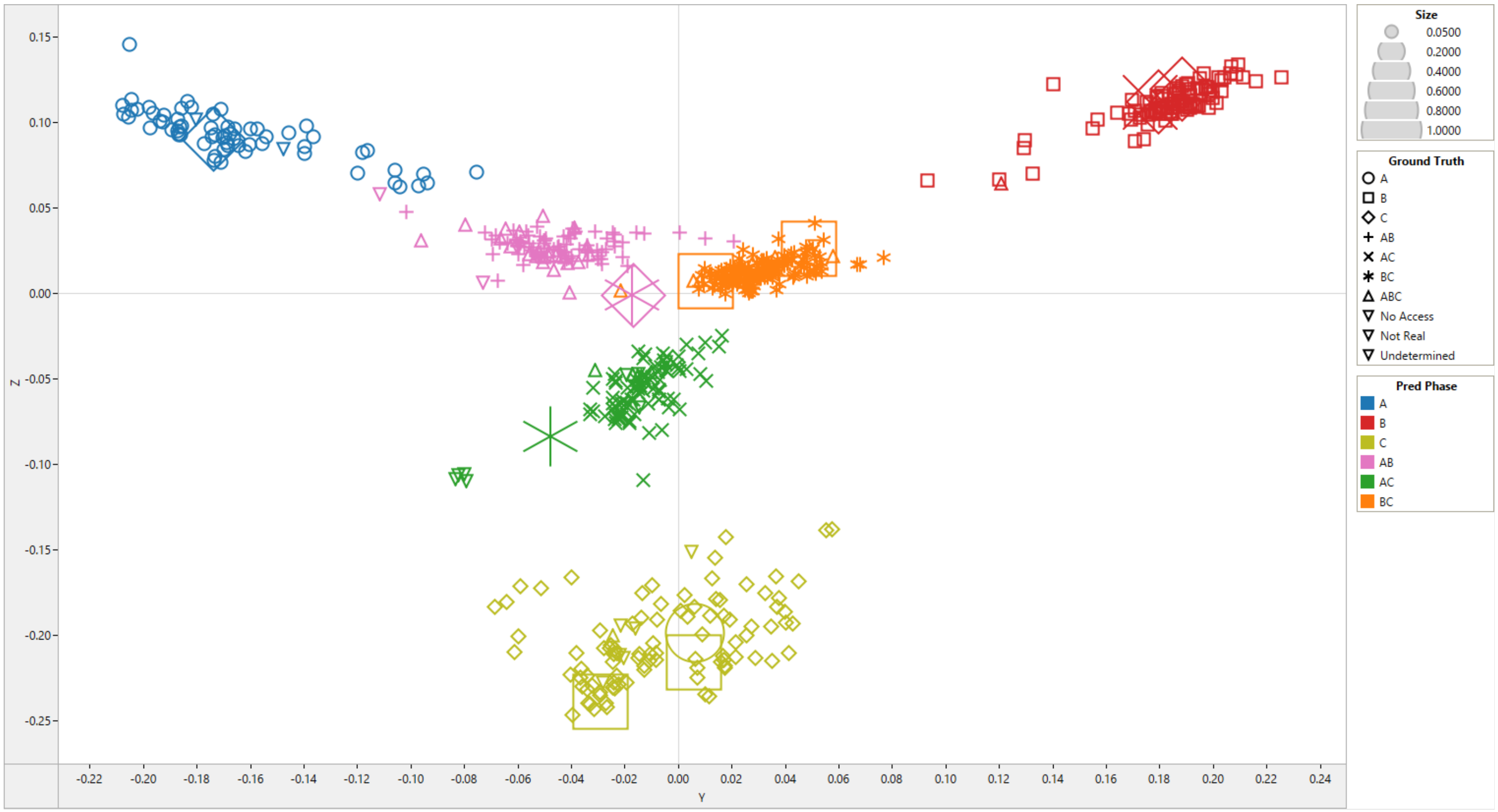

Figure 23. Correlation Clusters Plot – Feeder A

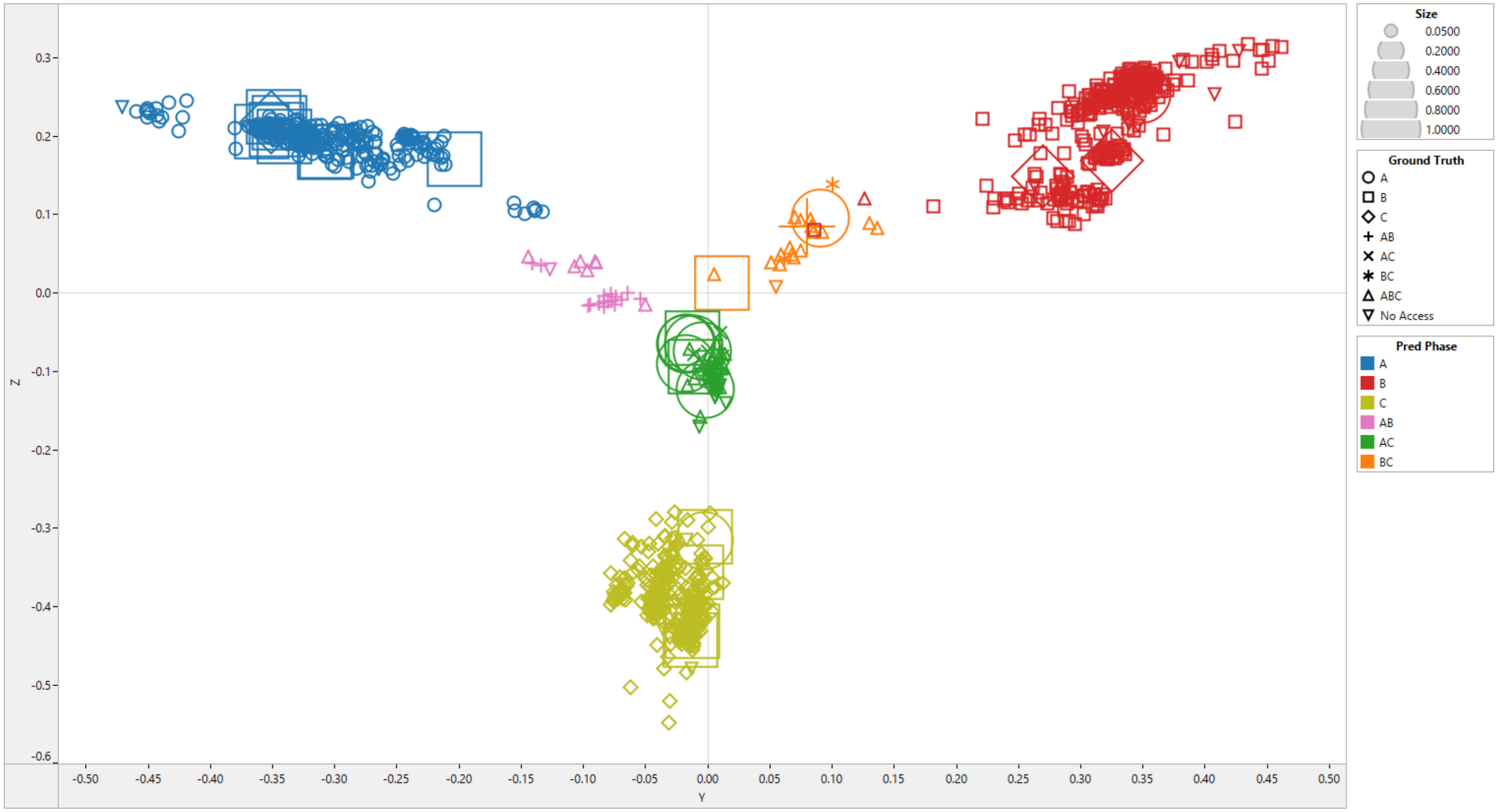

Figure 24. Correlation Clusters Plot – Feeder B

While the map and correlation plots add more confidence to the model prediction, without validation, an assumption for correct predictions can't be made. Therefore, SDG&E's label remains as the ground truth for these 40 meters.

Table 15 and Table 16 below are the updated confusion matrices for Feeder A and B, respectively. There are more L-N meters that do not match. Possible explanations include, 1) SDG&E's L-N meters are usually underground and cannot be virtually checked and 2) the model prediction does not perform as well for L-N meters.

Table 15. Updated Confusion Matrix – Feeder A

	A	B	C	AB	BC	AC	Total	% Match
A	**64**		**1**				**65**	**98%**
B		**98**	**2**		**2**		**102**	**96%**
C	**1**	**2**	**94**	**1**			**98**	**96%**
AB				**84**			**84**	**100%**
BC				**1**	**140**	**1**	**142**	**99%**
AC		**1**				**84**	**85**	**99%**
Total	**65**	**101**	**97**	**86**	**142**	**85**	**576**	**98%**

Table 16. Updated Confusion Matrix – Feeder B

	A	B	C	AB	BC	AC	Total	% Match
A	**259**	1	1		1	6	**268**	**97%**
B	8	**296**	4		1	2	**311**	**95%**
C	1	2	**249**				**252**	**99%**
AB				**16**	1		**17**	**94%**
BC					**2**		**2**	**100%**
AC						**10**	**10**	**100%**
Total	**268**	**299**	**254**	**16**	**5**	**18**	**860**	**97%**

In conclusion, the accuracy rate is between 97% and 98%. It is possible the real accuracy rate is even higher. It would be valuable to cross-validate the 40 meters where GMSV analysis could not be performed. Also valuable would be to have the ground truth about which phase is being metered for the other 196 meters that are labeled "ABC" or "No Info".

3.1.2 Phase Identification Results Discussion Part I: Effects from Data

Number of meters that "represent" each transformer

Several factors in the data source might affect the accuracy level. For example, as mentioned in the data description, the analysis does not use the voltage data for the whole frame, the data is only available for the selected one or two meters on each transformer. If one or two meters are enough to identify the transformers' phase, it will save data transferring bandwidth and data storage.

Will this setting affect the accuracy rate? Table 17 compares the accuracy rates for transformers with different numbers of associated meters per transformer with voltage data provided. As explained above, the accuracy rates are lower for L-N meters than L-L meters. Therefore, the comparison is shown in each category separately. For the L-L category, the accuracy rate is slightly higher when data is available for more meters on the transformer. When the number of meters with data increases from one to three, the accuracy rate increase from 95% to 100%. However, this can be explained by the fact that Feeder A has a greater number of large transformers than Feeder B, and Feeder A has a higher accuracy rate. When focusing on Feeder A, the accuracy rates are not vastly different, and for Feeder B, the sample is not big enough to draw any conclusion.

As for the L-N meter group, the results show no pattern. For both feeders, the accuracy rates are the lowest for the middle group, where transformers have two meters with voltage data.

Therefore, the conclusion is, there is no evidence the phase identification algorithm works better for transformers with more data.

Table 17. Accuracy Rate by Transformer Size

		Feeder A		Feeder B		Total	
Configuration Type	**# Meters per Transformer**	**# Meters**	**% Accurate**	**# Meters**	**% Accurate**	**# Meters**	**% Accurate**
L-N	1	5	100%	227	98%	232	98%
L-N	2	226	96%	572	96%	798	96%
L-N	3	33	97%	33	100%	66	98%
L-L	1	9	100%	12	92%	21	95%
L-L	2	252	99%	16	100%	268	99%
L-L	3	51	100%	0		51	100%
Total		**576**	**98%**	**860**	**97%**	**1,436**	**97%**

Length of time series data

Another factor is the number of months of valid data provided for each meter. If a longer period of data can significantly increase the accuracy rate, then it is worth incorporating longer time series into the analysis. Table 18 compares the accuracy rates by the number of sample months. "Full Data" means the meter includes all 22 months in the analysis; "Almost Full" means 20 or 21 months of data; and the other two categories are self-explanatory. The meters with less than half a year of data are all predicted correctly and there is not much difference among the other three categories' accuracy rates. Based on this analysis, we cannot draw any conclusive result for this dimension.

Table 18. Accuracy Rate by Number of Sample Months

		Feeder A		Feeder B		Total	
Configuration Type	**# Sample Months**	**# Meters**	**% Accurate**	**# Meters**	**% Accurate**	**# Meters**	**% Accurate**
L-N	Full Data	168	96%	508	96%	676	96%
L-N	Almost Full	83	98%	207	97%	290	97%
L-N	More than half year	11	91%	74	97%	85	96%
L-N	Less than half year	2	100%	43	100%	45	100%
L-L	Full Data	245	99%	21	100%	266	99%
L-L	Almost Full	53	100%	6	83%	59	98%
L-L	More than half year	7	100%	1	100%	8	100%
L-L	Less than half year	7	100%	0		7	100%
Total		**576**	**98%**	**860**	**97%**	**1,436**	**97%**

Reading frequency or interval length

The data frequency or the interval length is another factor that affects the results greatly. If the data comes in 10-minute intervals, with the rest unchanged, the data size decreases by half. Therefore, the data transferring and storing costs go down, and data processing is faster. On the other hand, however, when the voltages are averaged across 10-minute intervals rather than five-minute intervals, some of the phase specific signals may be averaged away and blended into the white noise on the grid. Additionally, as the phase signature movements are taken away little by little, the correlations are harder and harder to cluster.

Table 19 through Table 22 provide comparisons of the model prediction using 10-minute interval voltage data with ground truth and five-minute interval voltage data, for Feeders A and B. The 10-minute interval model uses the same set of parameters as the five-minute interval model, with no adjustment. This provides a better comparison between the two data settings, since all the differences are due to different interval lengths.

However, even though the parameters used to trim data are all the same, the results are different. For example, the frozen period is defined to have at least 12 consecutive intervals where the voltage remains linear or has no change. In a five-minute interval data setting, 12 intervals equate to one hour, and in a 10-minute interval data setting, 12 intervals equate to two hours. This means fewer data points are trimmed off due to the frozen period. When less data is trimmed off, more meters are included. In Table 19, the total number of meters is 997, two more than in Table 15.

On the other hand, when fewer data are trimmed off, more noise is kept in the model, which means it is more difficult to find correlation patterns, and fewer clear clusters.

For Feeder B, the two sets of results agree by 99.1%, but for Feeder A, there is some degree of confusion between phase AB and BC, as highlighted in red in Table 20 and Table 22.

Table 19. Confusion Matrix – Feeder A: comparing 10-min model prediction with ground truth

	A	B	C	AB	BC	AC	Total	% Match
A	64		1				65	98%
B		98	2	1	1		102	96%
C	1	2	93	1			97	96%
AB				63	5	13	81	78%
BC			1	61	77	1	140	55%
AC		1		19		71	91	78%
ABC	3	1	1	26	6	5	42	
No Info	3		6	6		4	19	
Total	71	102	104	177	89	94	637	81%

Table 20. Confusion Matrix – Feeder B: comparing 10-min model prediction with ground truth

	A	B	C	AB	BC	AC	Total	% Match
A	253	1	1	6	1	6	268	94%
B	8	295	4		2	2	311	95%
C	1	2	251				254	99%
AB				16	1		17	94%
BC					2		2	100%
AC						10	10	100%
ABC				8	16	22	46	
No Info	24	30	18	1	1	15	89	
Total	286	328	274	31	23	55	997	96%

Table 21. Confusion Matrix – Feeder A: comparing 10-min model prediction with five-min model prediction

	A	B	C	AB	BC	AC	Total	% Match
A	67						67	100%
B		102					102	100%
C			104				104	100%
AB	1			107	5		113	95%
BC				70	83		153	54%
AC				4		94	98	96%
Total	68	102	104	181	88	94	637	87%

Table 22. Confusion Matrix – Feeder B: comparing 10-min model prediction with five-min model prediction

	A	B	C	AB	BC	AC	Total	% Match
A	286			6			292	98%
B		328			2		330	99%
C			272				272	100%
AB				24			24	100%
BC				1	21		22	95%
AC						55	55	100%
Total	286	328	272	31	23	55	995	99%

Correlation cluster plots shed more light on understanding the difference between the two sets of model predictions. Figure 25 and Figure 26 below compare the correlation plots for Feeder A and B, respectively. For all four panels in the two figures, shape is defined by the five-minute interval model and color is defined by the 10-minute interval model, as shown in the legend section on the bottom of each figure. The unmatched meters are emphasized with larger icons.

For each figure, the left panel plots the projection of three-dimensional correlations from the five-minute model, and the right panel for the 10-minute model. The panels look similar for both feeders. It seems strange that such similar correlation plots generate different cluster results. For example, in Figure 25, the two orange squares look so out of place, and in Figure 26, it is obvious that the big chunk of purple stars near the center should be orange.

Referring to Figure 3, the algorithm flowchart diagram indicates the average correlations are calculated twice. The first calculation is the step provided in the top rectangle and the second calculation is the step provided in the bottom rectangle. The correlations from the first calculation define the kernels, and the correlations out of the second are plotted in Figure 25 and Figure 26 below. If kernels are defined using this second set of correlations, given the similarity between the left and right panels of each figure, the phase prediction will be similar for the five-minute model and 10-minute model accordingly. In Figure 23 and Figure 24, all colors are clustered properly, meaning that the kernels out of this algorithm outlined in Figure 3 converge with the kernel feed into this step. But on the right panels of Figure 25 and Figure 26, some colors are mixed, indicating that the model is not fully converged. One way to fix this issue is to manually adjust the data trimming parameters so that the white noise decreases, and the correlations show more pattern from each phase. Therefore, the cluster step is easier and yields better results. Another way is to loop it one more round until the process produces a converged prediction.

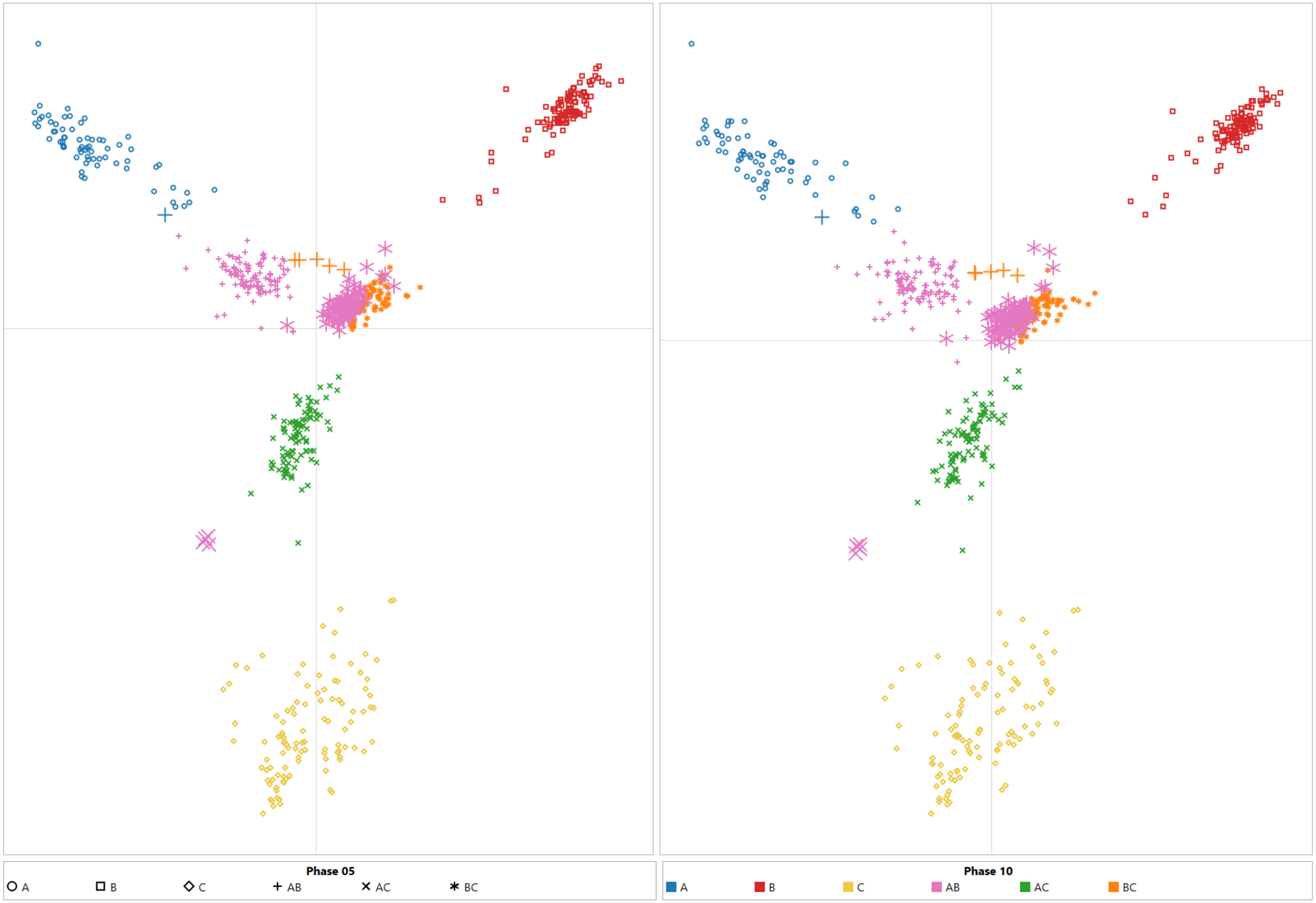

Figure 25. Correlation Clusters Plot – Feeder A: comparing between 5-min interval and 10-min interval model

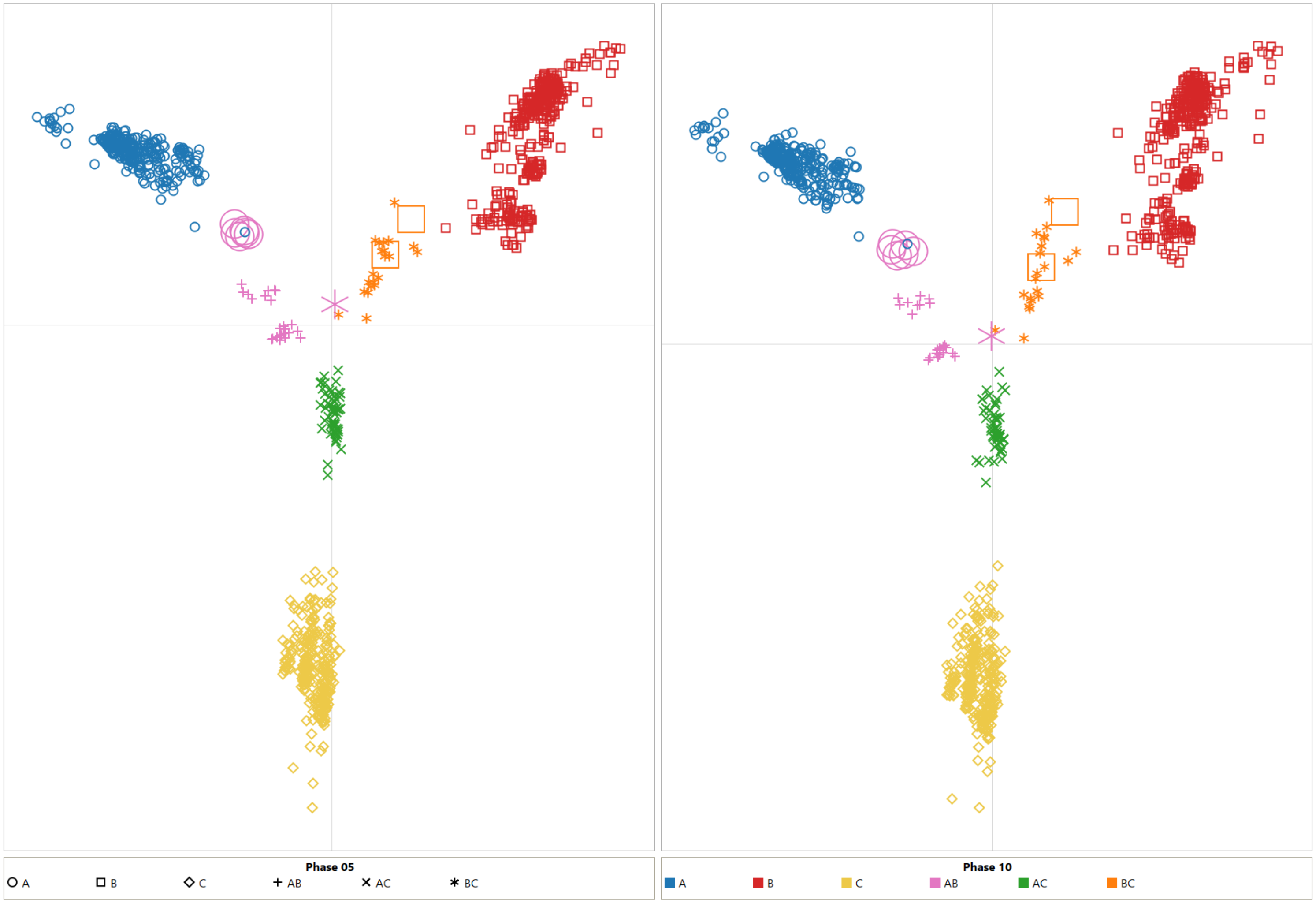

Figure 26. Correlation Clusters Plot – Feeder B: comparing between 5-min interval model and 10-min interval model

3.1.3 Phase Identification Results Discussion Part II: Model Statistics

Consistency rate

Consistency rate is another statistic worth mentioning. These metric measures how consistent the sample month predictions are. As explained in the phase identification algorithm, the final prediction is a summary of all sample month results. The consistency rate is defined as the number of months where the monthly prediction is consistent with the final results over the total number of months. It is expected that accurate predictions are more likely with a higher consistency rate.

Table 23 below compares the accuracy rates across different consistency levels. Feeder A has some meters with some sample month results that are inconsistent with the final prediction, and the L-L meter group shows decreasing accuracy rates when the consistency level drops. For Feeder B, almost all meters have 100% consistent predictions. Such results show strong confidence in the model, but at the same time contribute little to no value to understanding the relationship between consistency level and accuracy rate.

Table 23. Accuracy Rate by Consistency Level

		Feeder A		Feeder B		Total	
Configuration Type	Consistency Level	# Meters	% Accurate	# Meters	% Accurate	# Meters	% Accurate
L-N	100%	188	97%	829	97%	1,017	97%
L-N	90% and up	74	99%	2	50%	76	97%
L-N	Less than 90%	2	0%	1	100%	3	33%
L-L	100%	264	100%	27	96%	291	100%
L-L	90% and up	43	95%	1	100%	44	95%
L-L	Less than 90%	5	80%	0		5	80%
Total		**576**	**98%**	**860**	**97%**	**1,436**	**97%**

Hybrid index

Another important statistical output is the hybrid index. The hybrid index is used to separate L-N phases from L-L phases. The meters with a lower hybrid index are L-N, and the meter with a higher hybrid index are L-L. The Agglomerative Cluster method is used to decide on the cutoff point. If the model works well, the cutoff point should be obvious.

However, there are still meters closer to the cutoff points than the other meters. Those are the meters that pose some challenge to the model. Therefore, it is worth comparing the accuracy rates between the meters closer to the cutoff point and the meters farther away.

Table 24 provides such comparison, and the numbers look interesting. While Feeder B's accuracy rate increases as the distance from the cutoff point increases, Feeder A shows the opposite trend. For the L-N group on Feeder A, the accuracy rate is 100% for all the meters that are close to the cutoff points, and the rate drops to 98% and then 94% for meters farther away.

Table 24. Accuracy Rate by Distance from Hybrid Index Cut-Off Point

		Feeder A		Feeder B		Total	
Configuration Type	# Distance from Cutoff	# Meters	% Accurate	# Meters	% Accurate	# Meters	% Accurate
L-N	Very Close	5	100%	7	86%	12	92%
L-N	Close	18	100%	3	33%	21	90%
L-N	Far	123	98%	45	87%	168	95%
L-N	Very Far	118	94%	777	98%	895	97%
L-L	Very Close	4	100%	0		4	100%
L-L	Close	13	92%	7	86%	20	90%
L-L	Far	183	99%	5	100%	188	99%
L-L	Very Far	112	100%	16	100%	128	100%
Total		**576**	**98%**	**860**	**97%**	**1,436**	**97%**

3.1.4 Meter-to-Transformer Prediction Accuracy

As discussed in Section 2.3.4 Data Trimming, the meter-to-transformer algorithm trims off meters in the same way as the phase identification algorithm. Additionally, it also trims off meters with wrong latitude and longitude information, and the transformers for which valid voltage data is available for only one meter on the transformer.

The latitude and longitude information are important in meter-to-transformer algorithm because a meter is always connected to one of the closest transformers, if possible, to reduce the length of service wire and hence to reduce the energy loss. Therefore, the meter-to-transformer algorithm only searches for N (N is a parameter fed into the algorithm that can be adjusted, and usually takes the value of 10, 15, or 20) closest transformer for each meter as an initial mapping. Without valid latitude and longitude coordinates, the meter-to-transformer algorithm has no starting point.

The meter-to-transformer algorithm cannot deal with transformers with only one meter either. With no information on transformers' voltages, the algorithm must summarize the voltages across all meters on the transformer as a proxy for the transformer's voltage. If a meter is the only one on a given transformer, it is always 100% correlated to itself, and the algorithm does not work.

Table 25 below summarizes the matched rate for the meter-to-transformer model. Overall, 81% of the model predictions match SDG&E's records, and the other 19% show discrepancies. The rates look similar across the two feeders. On Feeder A, the match rate is 82%, and on Feeder B, it is 79%, slightly lower.

Table 25. Meter-to-Transformer Accuracy Rate

	Feeder A		Feeder B		Total	
	# Meters	% Match	# Meters	% Match	# Meters	% Match
Matched	384	82%	390	79%	774	81%
Unmatched	82	18%	104	21%	186	19%
Total	**466**		**494**		**960**	

Figure 27 and Figure 28 on the next two pages provide visualizations of the meter-to-transformer predictions on a map. The circles represent meters, and the stars represent transformers. The lines connecting stars and circles represent the imaginary power lines. If the line is green, the meter-to-transformer connectivity matches SDG&E's records. If, on the other hand, the line is red, it means the model suggests that the meter should be connected to the transformer on the other side of the red line. If the line is grey, it means that the voltage data is not provided or is not adequate to draw a conclusion.

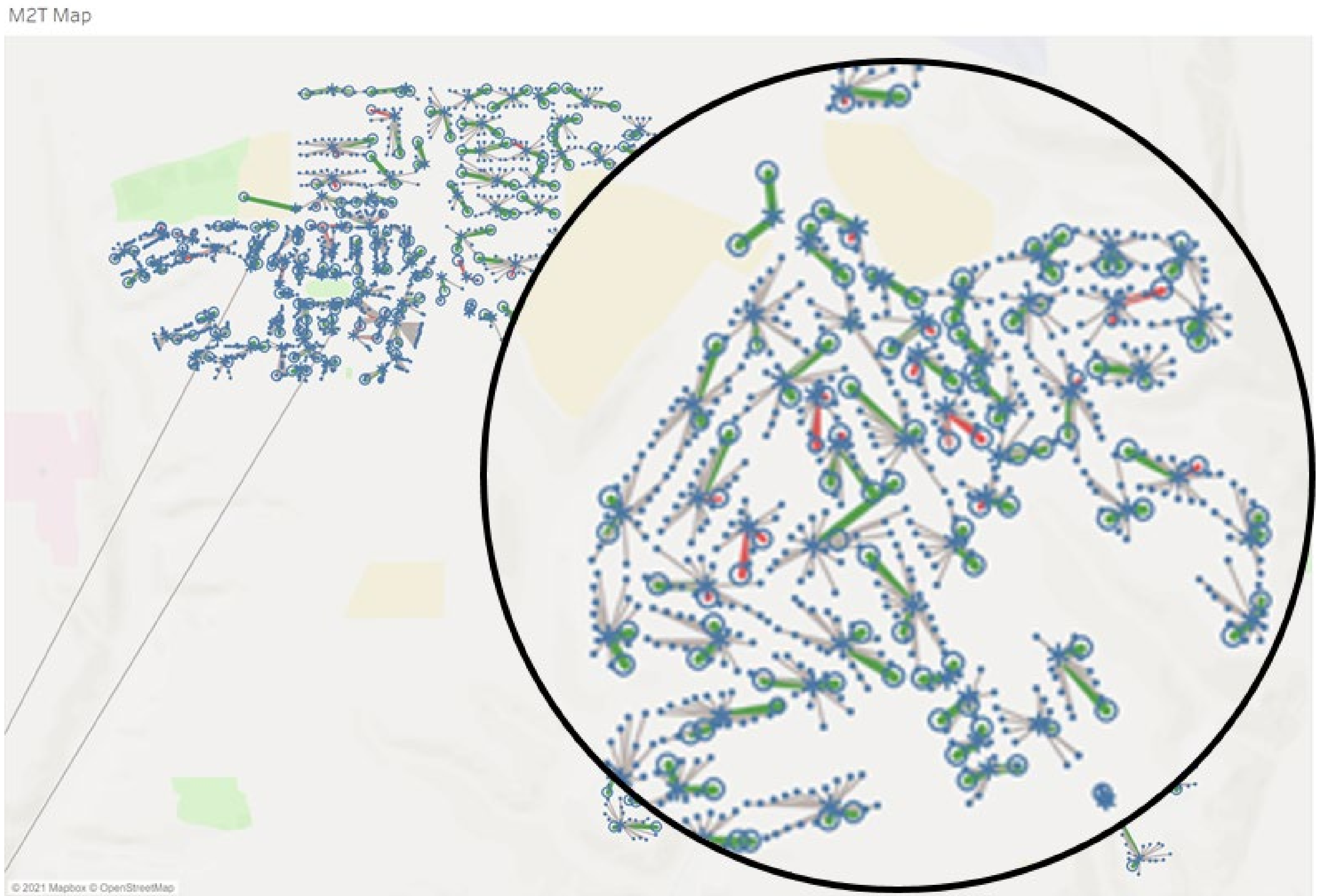

Figure 27. Meter-to-Transformer Prediction on Map – Feeder A

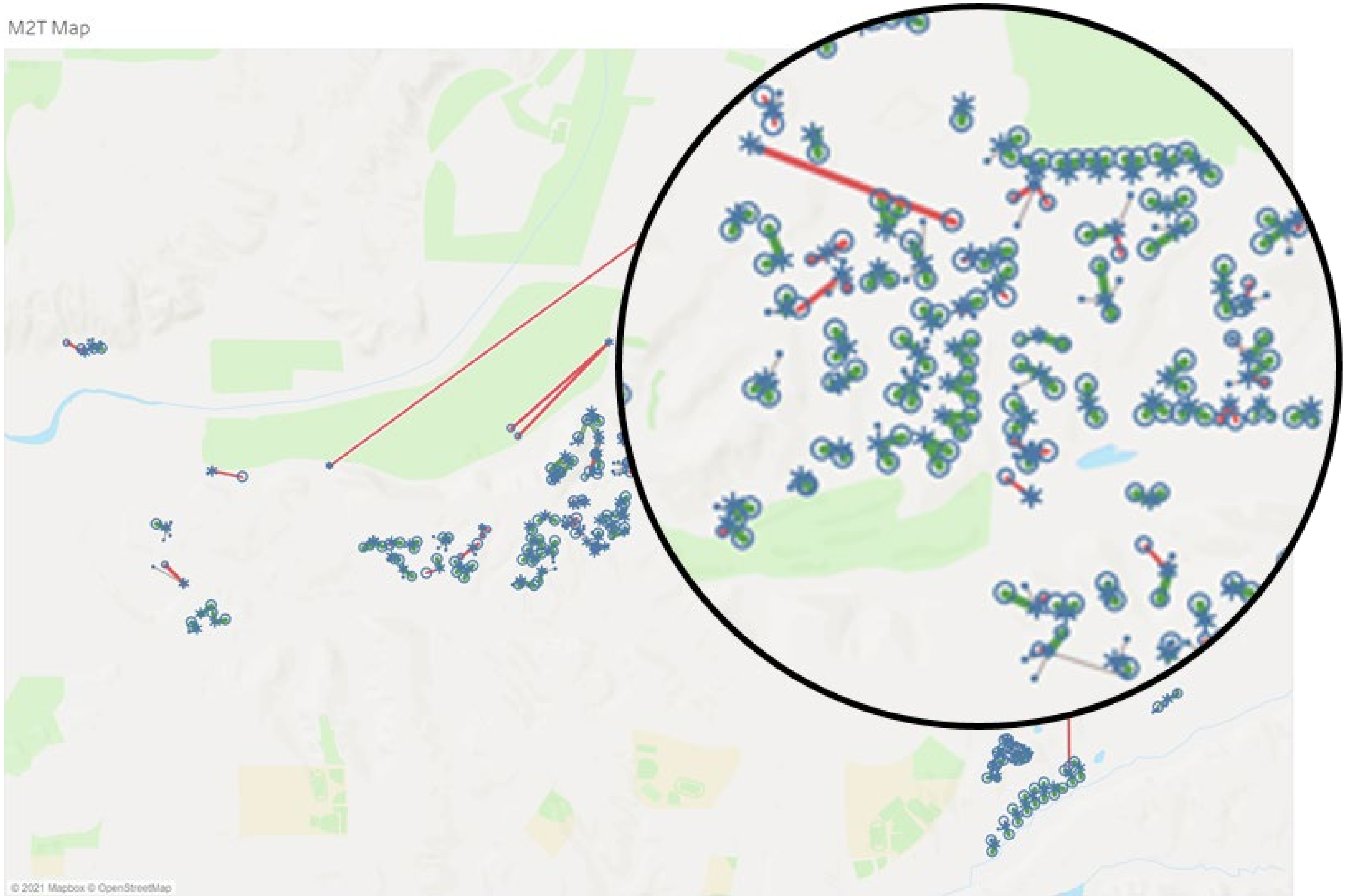

Figure 28. Meter-to-Transformer Prediction on Map – Feeder B

3.1.5 Meter-to-Transformer Results Discussion

As discussed in Section 3.1.2, there are some data issues that may affect the model performance. Section 3.1.2 discusses three issues: number of sample months, transformer size, and interval length or reading frequency. While the meter-to-transformer model was not tried using 10-minute interval data, this section discusses the other two factors.

Number of meters that "represent" each transformer

Table 26 below compares accuracy rate by transformer size. It shows how the accuracy rate increases as the number of meters on the transformer increases, from about 60% to 95% on transformers with three meters.

Transformer size is an especially crucial factor that affects the meter-to-transformer model dramatically. Since transformer meters are not measured by most utilities, transformer voltage is not available. The detour is to summarize the transformer's other meters' voltages as a proxy for transformer voltage. The meter-to-transformer model correlates each meter with all its nearby transformers' proxy voltages and assigns it to the transformer with the highest correlation.

Therefore, if there is only one meter, M, on a transformer, and when it is M's "turn" to apply correlation against each nearby transformer, its "home" transformer, the one that it is currently on, has no voltage, because there are no other meters on it.

In case of a transformer with two meters, the model is not very stable either. If either meter is mislabeled, the model prediction will not work for the other, because the model prediction for the second meter relies on the first one as a proxy for the transformer.

However, when the number of meters increases, one or two mislabeled meters does not affect the results as much, since the transformer's voltage is a summary of several meters, and the mistake is mitigated by the correct meters.

Table 26. Accuracy Rate by Transformer Size

Transformer Size	Feeder A		Feeder B		Total	
	# Meter	% Match	# Meter	% Match	# Meter	% Match
1	12	67%	33	61%	45	62%
2	394	81%	446	80%	840	80%
3	60	93%	15	100%	75	95%
Total	**466**	**82%**	**494**	**79%**	**960**	**81%**

Length of time series data

Table 27 below compares the accuracy rate by number of sample months, for Feeder A, and Feeder B separately. The results look counter-intuitive. As the number of sample months increases, the accuracy rate declines, from 85% to 79%. However, the decline is not a big one and not statistically significant. The standard deviation of the 85% accuracy rate for “Other” group is 0.057, or 5.7%, and hence 79% is just one standard deviation away.

Table 27. Accuracy Rate by Number of Sample Months

# Sample Months	Feeder A		Feeder B		Total	
	# Meter	% Match	# Meter	% Match	# Meter	% Match
Full	341	81%	310	76%	651	79%
Almost Full	116	86%	154	84%	270	85%
Other	9	89%	30	83%	39	85%
Total	**466**	**82%**	**494**	**79%**	**960**	**81%**

3.2 Updated Benefits Analysis

Initial discussions of the benefits for meter-to-transformer and phase identification hinged on the assumption that a utility can get 100% accurate field verification results if they are willing to put in the person-hours. In that context, the value of back-office solutions to meter-to-transformer and phase identification were tied to the tradeoff between time and money saved by avoiding truck rolls, and the reduced accuracy of the data-driven solution. While analyzing the phase identification results on Feeder A, however, it happened that the accuracy of the voltage correlation analysis (>98%) was greater than the accuracy of the field verifications (95%). The implications of this unexpected result are subtle, but profound. While it was estimated by SDG&E that typical field verifications also yield accuracies greater than 98%, the notion that a data-driven solution is necessarily less reliable than a manual inspection must be called into question. Moreover, use cases involving safety were mostly excluded from the initial phase identification benefits discussion on the grounds that field verifications are the most reliable source of truth. This report does not suggest that voltage correlation analysis should replace field verifications when safety is a concern. However, the results of this project indicate that a legitimate added benefit comes from the corroboration of field verifications against the output of a voltage-correlation based phase identification solution. If the phase of a meter as determined in a field verification matches the voltage correlation result, the expected accuracy is greater than 0.9996%. On the other hand, in the unlikely event that the field verification and back-office solution disagree on the phase, this prompts a more thorough reexamination in the field, potentially averting a safety issue. The other more obvious takeaway from the high phase identification accuracy is that any prospective reduction in cost and time should suffice as a reason to prefer the back-office solution over the field verifications for use cases that do not involve safety.

The results for meter-to-transformer did not significantly affect the initial benefits analysis.

4.0 Findings

A voltage correlation-based phase identification solution exists which achieves accuracies in the range of field verification accuracy (~98%). This accuracy comes from voltage data with a resolution of 0.15V, and an interval of five minutes collected for two years between October 10, 2018, and October 20, 2020. The voltage data were only provided for two meters per transformer within each feeder, and the solution was tested on two feeders (Feeder A and Feeder B), with different phase compositions. Feeder A had a relatively even distribution of all six possible phases (A, B, C, AB, BC, and AC). Feeder B had predominantly L-N phasing (A, B, and C).

A voltage-correlation-based meter-to-transformer solution exists, which achieved 80% accuracy when supplied with voltages for only two meters per transformer on Feeder A and Feeder B. Several accurate corrections to the field verified connectivity model were suggested, but for each correct suggestion, at least one incorrect suggestion was also generated. In addition, there were several suggestions that were both incorrect and unrelated to a “good” suggestion.

Field verification accuracies for both phase identification and meter-to-transformer were found to be lower than 100%. Field verification accuracy could only be tested using GMSV on sections of the feeder with overhead wiring. This process was time consuming, and so it was only completed thoroughly for the meter-to-transformer and phase identification examples where there was a discrepancy between the voltage-correlation result and the field verification result. GMSV analysis suggested that the utility field verification accuracy for transformer to phase connectivity was 95% on Feeder A. Feeder B did not have enough overhead wiring to merit a thorough analysis.

4.1 Findings Discussion

For phase identification, the findings of this demonstration are straightforward. A voltage correlation solution using data for two meters per transformer achieved accuracies on par with those of field verifications. Also, assuming the presence of all six possible phases, was an important configuration change that drastically improved the results on these feeders.

For meter-to-transformer, the limitations of the dataset led to the problem of incorrect suggestions generated for each correct suggestion. In particular, the incorrect suggestions are the necessary result of attempting to correct meter-to-transformer errors when there is only voltage data for two meters per transformer. This situation has a direct parallel in the computer science field of error correction, namely attempting to correct one-bit errors with a single bit message. The simplest code capable of correcting a single bit error in a single bit of data is the triple repetition code, which uses two parity bits for each bit of data. Similarly, when error correcting meter-to-transformer connectivity, three meters per transformer are required to detect and correct a single error. Four meters on the transformer are required to both correct a single error and detect the presence of two errors. With only two meters per transformer, the best that can be hoped for is the detection of an error. Even then, the problem is more complicated than in the binary data example. While two bits can either match exactly or mismatch completely, two meters’ voltage readings can correlate anywhere on the range [-1, 1], where +1 indicates a perfect positive linear relationship – as one variable increases in its values, the other variable also increases in its values through an exact linear rule; and −1 indicates a perfect negative linear relationship – as one variable increases in its values, the other variable decreases in its values through an exact linear rule. In practice, correlations near one are indicative of a "match", while low correlations near zero are indicative of a mismatch, but where to draw the line can be difficult. The findings from this experiment highlight some of the mathematical limitations of this approach to correcting meter-to-transformer. A voltage correlation-based meter-to-transformer solution that only has access to meter voltages will never be able to detect or correct connectivity errors on transformers with one or fewer connected meters. Such a solution will also be unable to reliably *correct* errors on transformers with two connected meters. Even in the case of three meters per transformer, this methodology would make incorrect suggestions in cases with two errors (Error Correction Code, 2021). Generally, the accuracy of this type of solution will increase with increasing numbers of meters per transformer due to the increased capability for error detection and correction. This was demonstrated in the results where meter-to-transformer accuracy was 80% for the transformers with two connected meters and 95% for the transformers with three connected meters.

Beyond the problems of error correcting, there is an inherent issue with only collecting data for anything less than *every* meter per transformer. This goes back to the value proposition for meter-to-transformer. In one example use case, utilities need to notify every customer affected by a planned outage. Failure to do so can result in the cancellation and subsequent rescheduling of the planned outage. In a use case like this, any solution that does not account for every single meter on a given transformer is inadequate. The answer to the question, "Can voltage data for two meters per transformer be used to accurately predict and correct meter-to-transformer connectivity on a given feeder?" is quite plainly, "no," without the need for any tests. Even if the voltage correlation solution could achieve 100% accuracy on that dataset, the results would still be insufficient for most of the use cases outlined in the value proposition. In almost all of them the benefit comes from knowing every meter that is attached to a given transformer. As such, the only solutions worth pursuing for meter-to-transformer are those which account for every meter. A major consideration that led to SDG&E opting to collect data for only two meters per transformer in this demonstration, was that of network traffic. To collect data for every meter on a feeder, further research should be conducted into the maximum network capacity. If it is the case that longer voltage intervals could reduce network traffic, then it is possible that the optimal data collection scenario on the given network requires longer voltage intervals. Preliminary explorations were conducted at the tail end of this demonstration which indicate that 10-minute intervals offer similar accuracies for phase identification. More research is needed in this area.

5.0 Conclusions

In the case of phase identification, the demonstrated technology successfully performed the desired functions by achieving accuracies comparable to those of field verification accuracies. With regards to the value proposition, adopting a similar voltage correlation based back-office solution to phase identification would save time and money, without sacrificing accuracy in every non-safety related use case. In the safety-related use cases, such a solution would also bolster utility confidence in field verified results.

In the case of meter-to-transformer, the demonstrated technology performed the desired functions with 95% accuracy when provided with voltage data for three meters per transformer and with 80% accuracy when provided data for only two meters per transformer. With data for two meters per transformer, while the technology was able to correct several of the field verified meter-to-transformer connections, the output included a much greater number of erroneous predictions. Many of these erroneous predictions were related to "good" predictions. This was the direct result of limiting the dataset to two meters per transformer. The mathematics of error correction suggest that accuracies even greater than 95% should be expected when data is provided for more than three meters per transformer. Separately, when analyzing the use cases outlined in the value proposition for meter-to-transformer, it is evident that a back-office solution for meter-to-transformer would only be worth implementing in a production setting if it collected data for every meter per transformer. Thus, it seems natural that follow-up tests should be conducted using a dataset with voltage data for every meter per transformer. A potential hurdle is that of network bandwidth. One proposed method for mitigating network traffic is longer voltage intervals, as similar accuracies were observed when performing phase identification using every other voltage datapoint. Even without further testing, the results from this demonstration indicate that with voltage data for every meter per transformer, the accuracy achieved by the meter-to-transformer solution would likely be greater than 95%.

6.0 References

References	Document Title
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2	San Diego Gas & Electric Company. (2018, May 1). *Application of San Diego Gas and Electric Company (U902-E) for Approval of Electric Program Investment Charge Terminal Plan for Years 2018 – 2020.* https://www.sdge.com/sites/default/files/FINAL_313383_SDG%2526E_Third_Triennial_EPIC_Application_2018-2020.pdf
3	Neelam Tyagi. (2020, December 21). What is Confusion Matrix? https://www.analyticssteps.com/blogs/what-confusion-matrix

PART III

Part III captures the results of Methodology B, the second of two methodologies where SDG&E worked with an external vendor.

Part III List of Illustrations

Part III List of Tables

Part III List of Acronyms

Acronym	Acronym Description
AMI	Advanced Metering Infrastructure
ADMS	Advanced Distribution Management System
AssetID	Asset Identification number
CIS	Customer Information System
CPUC	California Public Utilities Commission
COTS	Commercial off-the-shelf product
DERMS	Distributed Energy Resource Management System
DER	Distributed Energy Resource
EAM	Enterprise Asset Management
EV	Electric Vehicle
GIS	Geographic Information System
Phase ID	Phase Identification
SCADA	Supervisory Control and Data Acquisition
SaaS	Software as a Service
UI	User Interface

1.0 Overview

Methodology B demonstrated use of an established, data analytics platform to ingest, analyze, evaluate, and display results for end point phase identification and meter to transformer mapping. The project was organized into three tasks.

Task 1: Phase Identification

The phase identification algorithm was validated to ensure its applicability to the selected SDG&E feeders. This step was important to ensure assumptions made (e.g., secondary network topology, number of available measurements, switch status, etc.) when developing the algorithms would apply for the selected feeders, and modifications to the algorithms could be made as necessary. This task included network data information collection from SDG&E's planning models, development of test systems, AMI data cleansing, and development of visualizations for the selected feeder.

The validation was performed using the information from the planning network model and through field verification. The former approach was used to perform the first stage of validation. The field verification was performed as part of Task 3, discussed below. The algorithm was recursively tuned using machine learning to improve the overall accuracy of the prediction.

The output of this task was phase identification of the selected feeders. This was provided through a secure access portal to the vendor platform. Supporting documentation was provided and knowledge sessions were conducted with SDG&E stakeholders.

Task 2: Meter-to-Transformer Mapping

An algorithm was configured to determine the association of meters to service transformers using AMI data. The AMI data and information collected for Task 1 was used in this algorithm. Additional data such as geographical location, impedance parameters, and existing meter mapping information was used in the optimization of the algorithm. The solution used existing static meter-to-transformer mapping information for initial validation of results during the algorithm development phase. The final validation included verification of meter-to-transformer connectivity at selected locations in the field and fine-tuning the algorithm as needed. The final validation was addressed as part of Task 3 discussed below.

The output of this task was twofold:

1. Implement analytics based on geospatial data of meters and transformers, such as methods using latitude/longitude location data to evaluate meter-to-transformer association and suggest new transformers for service points located implausibly far from their assigned transformer.
2. Implement analytics based on five-minute AMI voltage data and hourly (in some cases 15-minute) AMI consumption data, such as methods which identify meters on the same transformer based on short term voltage and current patterns on the individual meters.

The output of this task was provided through a secure access portal to the vendor application. Supporting documentation was provided and knowledge transfers sessions were conducted with SDG&E stakeholders.

Task 3: Field Validation

To determine the validity of the demonstrated phase identification and meter-to-transformer mapping algorithms, existing information in the GIS served as a reference to check the accuracy of the results. However, neither the results nor the GIS database can be perfect. Mismatches between the results from the algorithms and the GIS database are expected, which requires checking the ground truth in the form of field visits. In this task, SDG&E performed field checks to verify the phase connectivity and meter-to-transformer associations at selected locations.

The output of this task was field validation and application configuration. Secure access to the vendor application was provided in order to review the validated Supporting documentation was provided and knowledge transfers sessions were conducted with SDG&E stakeholders.

2.0 Methodology Approach

2.1 Supporting SDG&E Infrastructure and Data Requirements

The solution was configured in a secure vendor hosted environment, hence there were no specific infrastructure requirements for the project scope. The following data was used in this demonstration:

- One year of SCADA (voltage and consumption) data
- One year of five-minute AMI (voltage) read data available for four circuits/feeders (both for three-wire and four-wire systems*)
- One year of coincidental interval load data for the set of AMI meters under study
- Applicable AMI events and exceptions data for the set of AMI meters under study
- Baseline system topology and asset relationship model (e.g., GIS, CYME, distribution network planning model, etc.)
- Geospatial information and locational data were provided for applicable assets, including but not limited to meters, transformers, substations, and medium voltage assets under study

** - The four circuits used in this methodology are identified as Feeder/Circuit A, B, C, and D. Feeder/Circuits A and B are the same circuits used across all three methodologies. While Circuits C and D are only used in this methodology.*

In addition to the input data outlined above, SDG&E provided the field collected data for Circuits A and B to evaluate the prediction accuracy. These data included the phase information and meter-to-transformer connectivity.

2.2 Execution of Demonstrations

As per the project tasks detailed in Section 1.0, demonstrations were carried out at four key milestones:

- Demo #1: Initial run of the algorithm
- Demo #2: Results based on field data comparisons
- Demo #3: Results from second optimized run of the algorithm against additional two circuit data
- Demo #4: Final demonstration of the complete results

In addition, SDG&E was provided access to the hosted solution for their independent review and evaluation. Due to COVID-19 restrictions, there was no opportunity to conduct onsite in-person reviews.

2.3 Use Case Execution

The use cases were executed within the vendor's commercial off-the-shelf platform in their secure hosted environment. The use cases were initially evaluated using assorted options of statistical algorithms to identify and reconcile transformer phase assignment and meter-to-transformer relationships. Based on the quality and availability of the circuit data, appropriate statistical algorithms such as K-means, Gaussian mixture models, and Bayesian model were chosen for the use case execution.

The use case outcomes were regressively improved through machine learning, geo clustering, and appropriate data filtering techniques to compare the signal with meter voltage (interval Vh) and association with one another and to a given transformer.

Once the computational analysis was complete, the system generated a representative connectivity model from meter to substation of the circuits. This representative model highlights differences between the computed model and the "as-found" model, where the "as-found" model represents the current GIS and distribution network planning model.

Figure 1 provides a snapshot of various visualizations available to the users of the system to review, analyze, and validate the use case results.

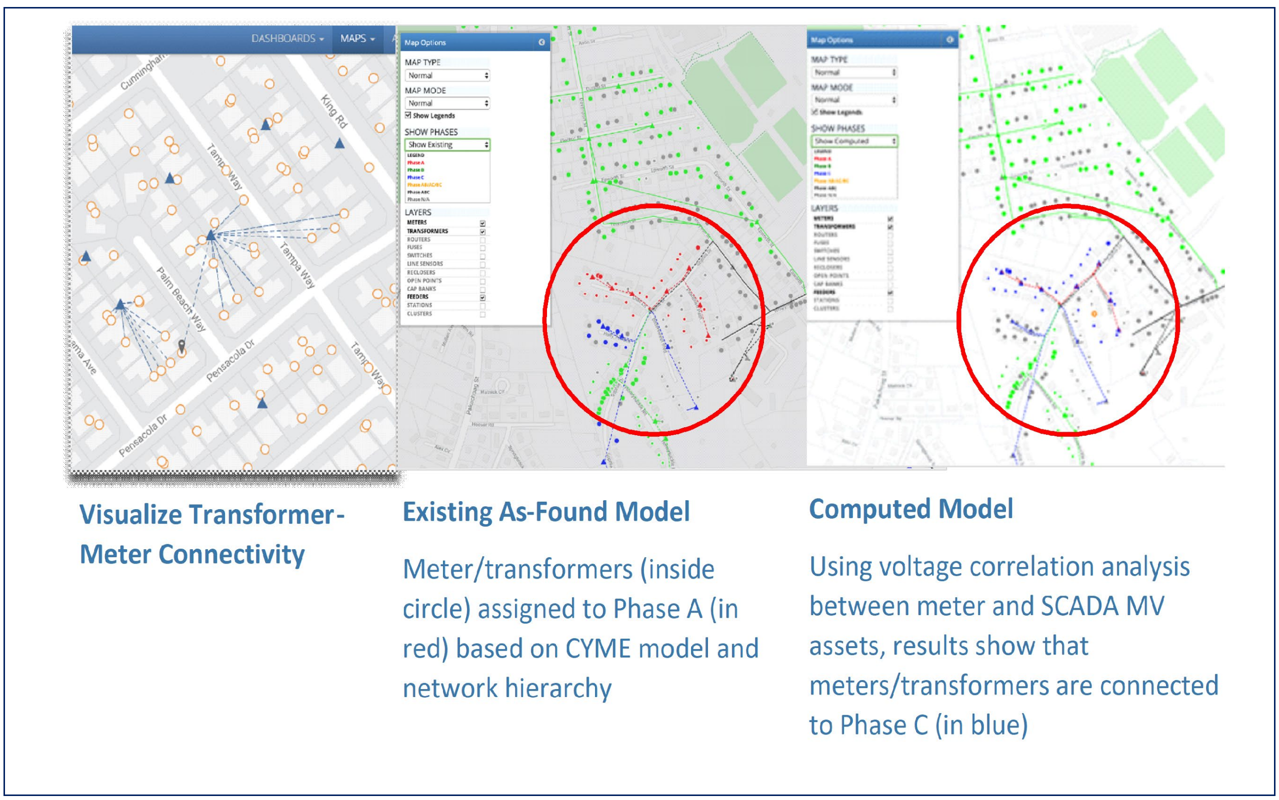


Figure 1. Indicative Interface to Analyze Results of Automated Mapping

One of the key elements of the use case demonstration is the ability to support an intuitive interface to various stakeholders within SDG&E. The use case outcomes were communicated via dashboards and mapping views of the circuit data. PART III, Appendix A provides snapshots of relevant interfaces that supported the overall data analysis for the stakeholders.

In addition to providing demonstrations of the results for phase and connectivity use cases, the vendor also utilized SDG&E provided data to implement and demonstrate the realization of advanced analytics such as Transformer Utilization and Voltage Management. PART III, Appendix B provides an overview of additional potential to use the AMI and SCADA data aggregated through this project.

3.0 Results

The summary below provides the key results from use case execution:

- Automated algorithm results for the sample SDG&E Circuits A and B closely correlated with actual field data for phase mismatches at approximately 92% predictability and connectivity issues at 89% predictability. The solution flagged approximately 9% false positives. A false positive occurs when identified meter-to-transformer mismatches are not correct.
- The solution was able to generate a high level of correlation despite the availability of less than 45% of valid/available voltage data for the sampled meters within the SDG&E territory.
- Circuits C and D were successfully processed; however, accuracy was not defined due to lack of field data.
- A major source of data gaps was associated with the availability of voltage data for the critical assets (meters and transformers).
- The solution enabled an interactive analytical interface in a secure hosted environment for easy access to the results and to conduct further investigation. The solution provided a view of data quality gaps that can be addressed to improve the overall quality of prediction.
- Availability of SCADA voltage as a reference improved accuracy of overall results.

Summary results of the use cases executed for the four circuits are presented below and grouped by two runs (iterations) of the algorithm.

Run 1: Circuits Validated with Field Data

Run 1 of the algorithm included analysis for phase identification and meter-to-transformer mapping for circuits A and B. The vendor first ran the algorithm using the circuits without the benefit of field validated results, and then compared the results to the field validated data. The tables below summarize the results and associated metrics:

Table1: Summary Base Meter Statistics for Circuits A and B

Circuit Reference	Total Meters
Circuit A	5,172
Circuit B	2,393

Importantly, there was limited AMI meter voltage data for both circuits, especially Circuit A. The table below summarizes the valid source meters that were used for the prediction based on valid data:

Table 2: Valid Meter Data Statistics Referenced for Final Configuration

Reference	Meters with Voltage Data	Percentage Circuit
Circuit A	674	13.0%
Circuit B	947	39.6%

The raw data from AMI and SCADA was normalized and the waveforms correlated using the vendor's algorithm to predict the phase ID mismatch and meter-to-transformer corrections. Tables 3 and 4 below summarize the results of the algorithm:

Table 3: Phase ID Prediction Accuracy Statistics for Circuits A and B

Circuit Reference	Total Meters	Phase ID prediction accuracy compared with field validation	
		# of Meters	% Accuracy
Circuit A	5,173	284	83%
Circuit B	2,393	145	92%

Table 4: Connectivity Mismatch Accuracy Statistics for Circuits A and B

Circuit Reference	Total Meters	Meter-to-transformer connectivity mismatch prediction accuracy compared with field validation	
		# of Meters	% Accuracy
Circuit A	5,173	186	65%
Circuit B	2,393	129	89%

Run 2: Circuits C & D Summary Results

Run 2 results are based on the execution of the algorithm against the two additional circuits, C and D. Run 2 was primarily focused on prediction and enunciating the gaps in the source data that needed attention. Field validation was not carried out for Run 2 circuits; hence the accuracy of prediction is not applicable.

Table 5: Meter Data Statistics for Circuits C and D

Circuit Reference	Total Meters
Circuit C	1,422
Circuit D	357

Table 6: Percentage of Successfully Processed Assets for Prediction – Circuit C

Circuit C	Assets processed
Successfully processed meter analysis	30%
Successfully processed transformer analysis	8%

Table 7: Percentage of Successfully Processed Assets for Prediction – Circuit D

Circuit D	Assets processed
Successfully processed meter analysis	84%
Successfully processed transformer analysis	80%

The tables below highlight the nature of source data issues that were flagged during the analysis that degraded the overall accuracy. In some cases, there was no run due to lack of valid data.

Table 8: Source Data Issues Categorized by Assets – Circuit A

Device	Issue Type	Count	Total Devices	Issue %
Meter	Missing Existing Phase	2,888	5,173	55.83%
Meter	Missing GIS Data	5	5,173	0.10%
Meter	Missing Nominal Voltage	4,496	5,173	86.69%
Transformer	Missing Existing Phase	2	325	0.62%
Transformer	Missing GIS Data	1	325	0.30%
Transformer	Missing KVA rating	2	325	0.60%
Transformer	Missing Primary Voltage	325	325	100.00%
Transformer	Missing Secondary Voltage	325	325	100.00%

Table 9: Source Data Issues Categorized by Assets – Circuit B

Device	Issue Type	Count	Total Devices	Issue %
Meter	Missing Existing Phase	283	2,393	11.83%
Meter	Missing GIS Data	54	2,393	2.26%
Meter	Missing Nominal Voltage	1437	2,393	60.05%
Transformer	Missing Existing Phase	2	649	0.30%
Transformer	Missing GIS Data	2	649	0.30%
Transformer	Missing KVA rating	2	649	0.30%
Transformer	Missing Primary Voltage	649	649	100.00%
Transformer	Missing Secondary Voltage	649	649	100.00%

Table 10: Source Data Issues Categorized by Assets – Circuit C

Device	Issue Type	Count	Total Devices	Issue %
Meter	Missing Existing Phase	18	1,422	1.30%
Meter	Missing GIS Data	22	1,422	1.50%
Meter	Missing Nominal Voltage	412	1,422	29.00%
Transformer	Missing Existing Phase	14	733	1.90%
Transformer	Missing GIS Data	14	733	1.90%
Transformer	Missing KVA rating	14	733	1.90%
Transformer	Missing Primary Voltage	733	733	100.00%
Transformer	Missing Secondary Voltage	733	733	100.00%

Table 11: Source Data Issues Categorized by Assets – Circuit D

Device	Issue Type	Count	Total Devices	Issue %
Meter	Missing Existing Phase	2	357	0.60%
Meter	Missing GIS Data	6	357	1.70%
Meter	Missing Nominal Voltage	106	357	29.70%
Transformer	Missing Existing Phase	3	197	1.50%
Transformer	Missing GIS Data	3	197	1.50%
Transformer	Missing KVA rating	3	197	1.50%
Transformer	Missing Primary Voltage	197	197	100.00%
Transformer	Missing Secondary Voltage	197	197	100.00%

3.1 Results Discussion

In this methodology, the vendor executed the two use cases in a hosted environment with the data provided by SDG&E. The vendor platform provided predictions with high accuracy for the sample circuits that matched with field verified data for Circuits A & B. This was especially prominent for circuits that provided adequate AMI voltage and SCADA reference data, meeting the data input requirements of the use cases.

Data Processing

The project successfully processed all the data from the four circuits for both use cases based on the availability of AMI and SCADA data on the assets.

Prediction Accuracy

The demonstration proved that using data analytics to automatically identify the phase of meters is possible with accuracy ranging from 83% - 92%. Prediction accuracy for identifying incorrect transformer to meter connectivity was assessed at 65% - 89% accuracy.

Accuracy of the prediction correlated with the availability of AMI data as demonstrated in Circuit A which had only 13% coverage of voltage data resulting in lower accuracy compared to Circuit B. Prediction accuracy for Circuits C and D was not done due to nonavailability of field data.

Data Quality

Source data quality was a key metric that defined the overall percentage of processing and accuracy as summarized in Table 11. The main data issue was the absence of nominal voltage in approximately 60% of the assets. Results of the analysis persisted in the hosted solution with an interactive interface that supported the overall results. PART III, Appendix A provides snapshots of visualizations that supported SDG&E stakeholder analysis of the algorithm results.

3.2 Updated Benefits Analysis

This demonstration provided considerable insights into SDG&E circuit data, format, and highlighted the quality of data that helped articulate the following additional benefits.

- Provide advanced analytics using AMI and SCADA data to establish transformer utilization metrics. This will benefit operational teams to prioritize and more importantly, proactively resolve issues that may cause outages.
- Voltage metrics from AMI can be assessed for power quality and benefit the operations team to identify and remediate voltage quality issues.
- Accurate phase ID prediction helps with improved phase balancing. This will help the operations team to reduce losses and associated outages and improve customer satisfaction.
- Increased penetration of DERs and related impacts to circuits is a major challenge to SDG&E's service territory. Accurate phase ID prediction can assist the overall interconnection process and thereby contribute to the overall carbon offset/de-neutralization goals.

4.0 Findings

This methodology demonstrated analytical approaches to phase identification and meter-to-transformer mapping using two meters per transformer. The vendor first ran the circuits with no reference to field data and subsequently compared the results with the field validated results. Results were then presented in the vendor's commercial off-the-shelf application. As presented in the summary section above, the match between the algorithm and field results were closely correlated as captured in Table 3 and Table 4. For phase identification, results of 83% and 92%, and for meter-to-transformer connectivity, results of 65% and 89% were achieved for circuits A and B respectively. As surmised, the input data constraint of two meters per transformer affected the overall accuracy results in both phase identification and meter-to-transformer mapping. Publicly available studies, Pacific Gas & Electric (2018) and Wenyu Wang (2016), indicate phase identification accuracy levels ranging from 90% to 97% without the two meter per transformer constraint employed in this demonstration.

5.0 Conclusions

While not superior to field validated results, estimated to be above 95%, analytical approaches for phase identification using this methodology appear adequate for operational use cases as discussed in PART I, Section 6.1.2. Further, the accuracy achieved using the analytical approach in this methodology are comparable with the results from known studies, Pacific Gas & Electric (2018) and Wenyu Wang (2016), where minimal constraints were applied. However, results for meter-to-transformer mapping may not be sufficient. While there are no industry standards for meter-to-transformer mapping, 65% and 89% may be too low to warrant full-scale deployment. Minimum standards must be established by SDG&E to determine whether this solution should be pursued.

Data cleansing plays a significant role in the overall accuracy. This methodology highlighted data quality gaps that warranted further investigation and prior actions to support full-scale deployment. This is evident in the phase identification results for circuit A at 83%. The source data gap issues are provided in Table 9.

Of note, this methodology also highlighted the effectiveness of a user-friendly interface to study the results of the algorithm in an engineering view for user interactions and various optimization assessments to improve the overall performance of the algorithm. While beyond the scope of this demonstration, several other use cases were identified that went beyond phase identification and meter-to-transformer mapping that could be of benefit to SDG&E. These additional use cases are identified and discussed in PART III, Appendix B.

6.0 References

References	Document Title
1	Pacific Gas & Electric Company. (2018, November 28). *EPIC 2.14 Automatically Map Phasing Information*. https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.14.pdf
2	Wenyu Wang, Nanpeng Yu, Brandon Foggo, and Joshua Davis. "*Phase Identification in Electric Power Distribution Systems by Clustering of Smart Meter Data*", 2016 15th IEEE International Conference on Machine Learning and Applications (ICMLA).

Part III Appendix A – Automated Mapping Interactive Interface

The vendor platform provides an indicative interface for business stakeholders to visualize and investigate the results of the algorithm for computed phase vs. assigned phase. Mapping based reviews of the circuits is an effective way to validate the results and compare the results in a spatial context.

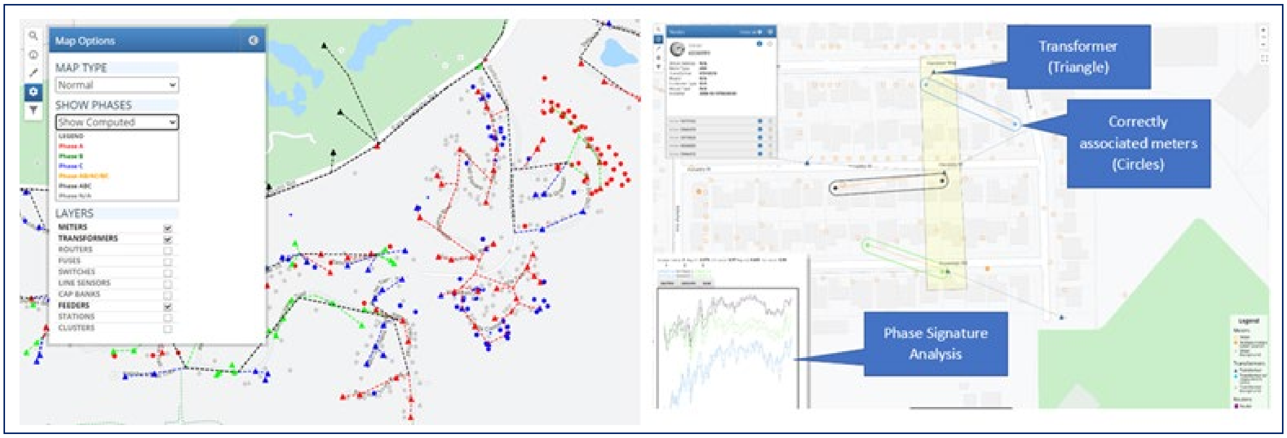


Figure 2: Visualization of Results of the Algorithm in Interactive Mapping Views

The key to understanding the algorithm is to visualize the voltage analysis in a convenient graphical format. Figure 3 below provides a sample view of the options available for the users to investigate the results of AMI and SCADA analysis.

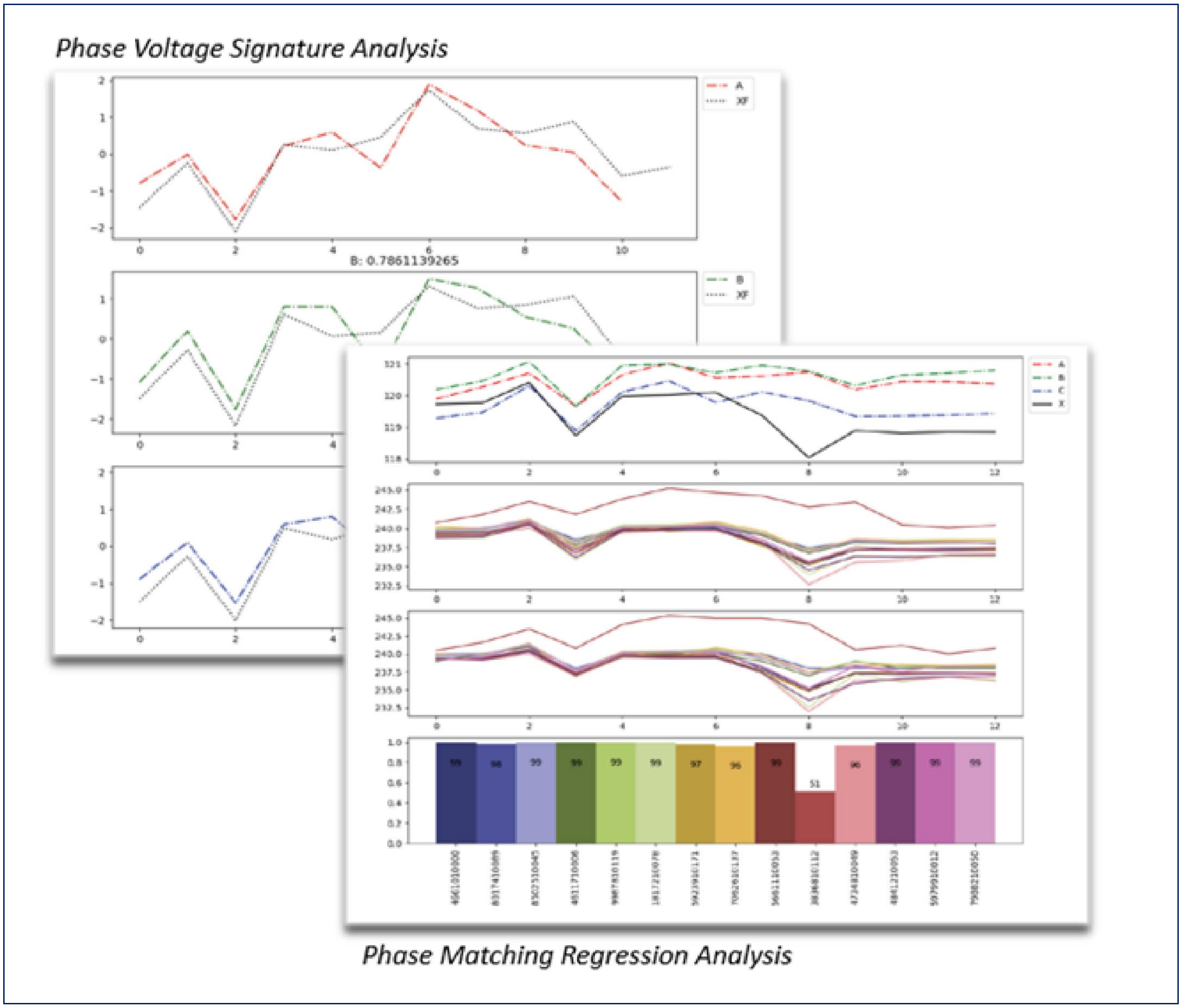


Figure 3. Visualization of Results of the Algorithm in Interactive Mapping Views

Configurability is a critical feature to review, optimize and iterate the results of algorithm until the desired accuracy is reached. Figures 4 and 5 below demonstrate the options to tune the algorithm interactively and visualize the results.

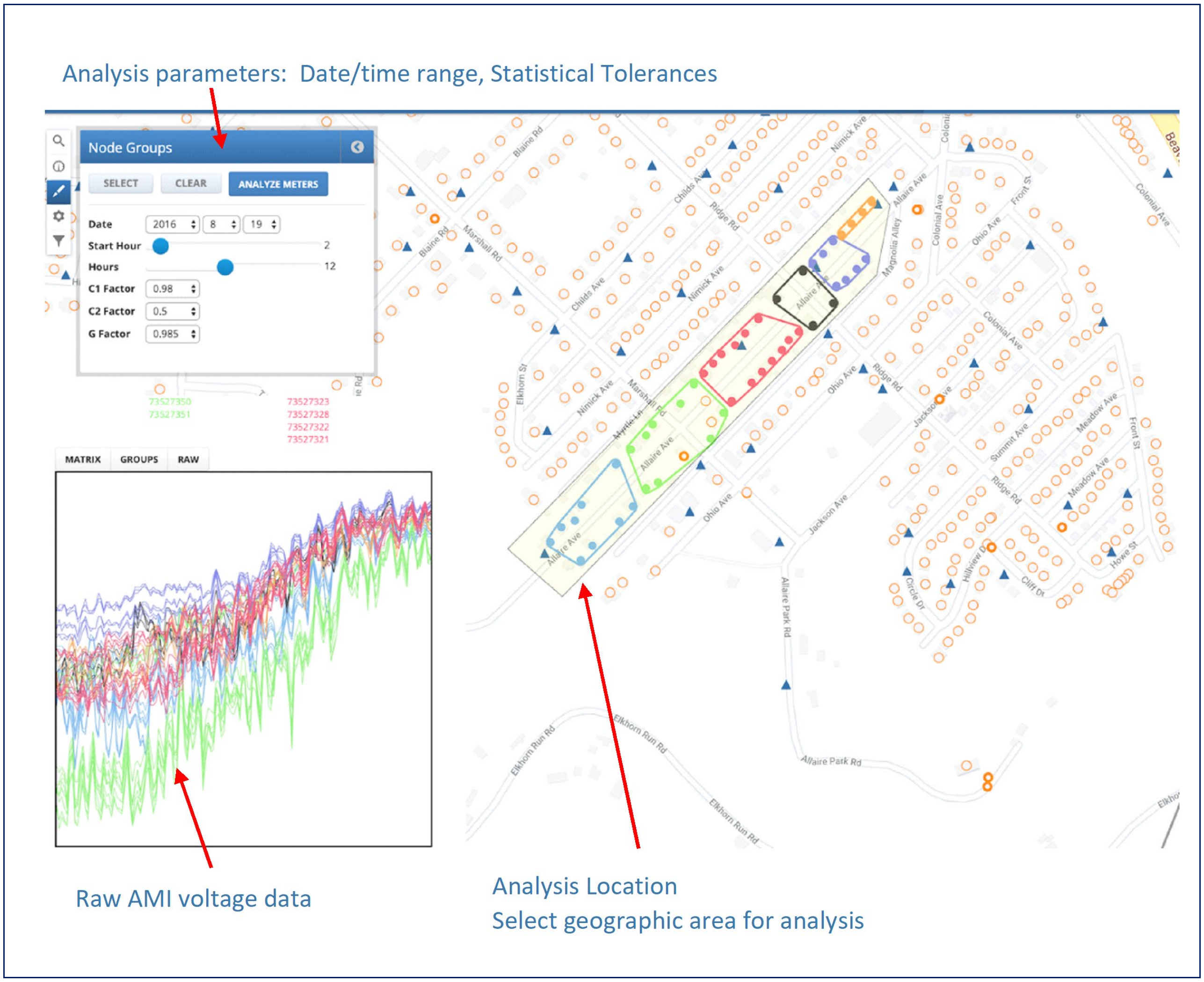


Figure 4: Options to Tune and Optimize the Algorithm - Engineering Tool 1

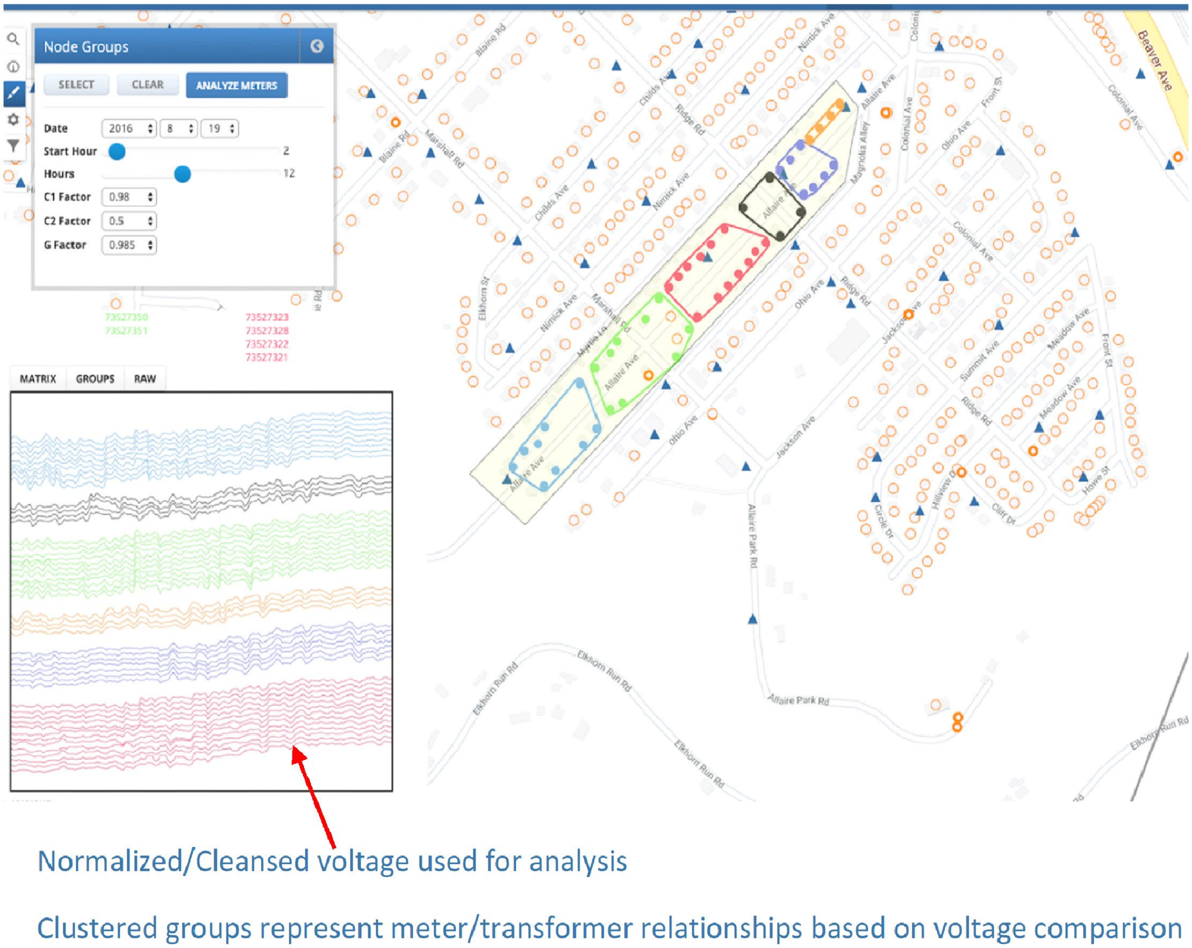
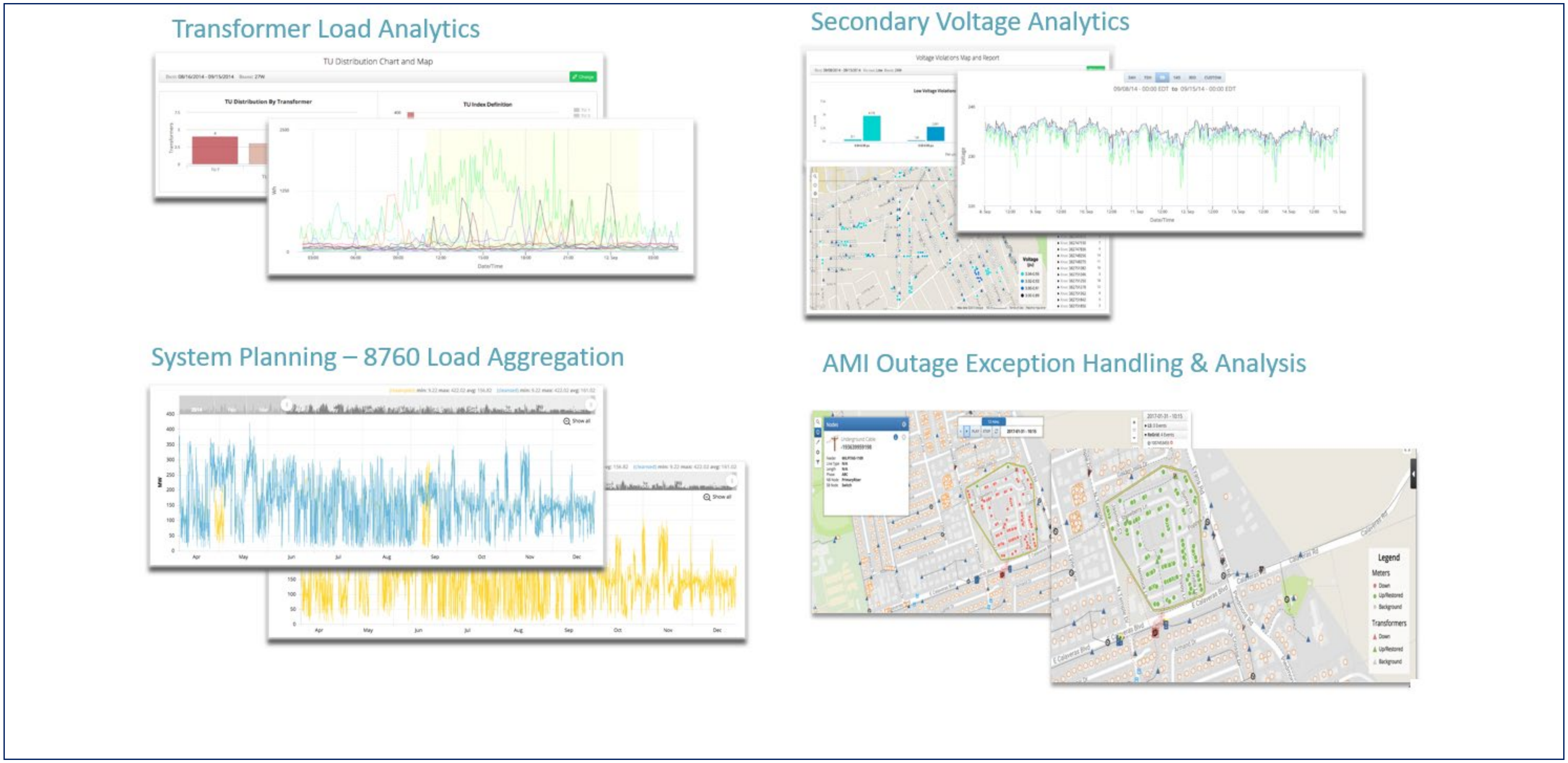


Figure 5: Options to Tune and Optimize the Algorithm - Engineering Tool 2

Part III Appendix B – Automated Mapping Extended Use Cases

This section highlights additional use cases that can be supported by extension of the AMI and SCADA data for operational purposes and thereby improve the overall return on investment in the project. These are recommended use cases for SDG&E's validation as part of the next steps.



Transformer Load Analytics (Transformer Utilization)

Use cases: Asset management, planning

Combining the increased adoption of distributed generation and electric vehicle (EV) systems on the grid with an aging utility infrastructure, the importance of monitoring transformer utilization is a growing necessity to mitigate against accelerated loss of life and prevent downstream impacts to customer reliability. The Transformer Utilization (TU) analytics focuses on evaluating overload conditions on individual transformers. The system collects meter load data and assesses the aggregate load at the transformer level. The meter-to-transformer connectivity hierarchy uses a known relationship model or leverages the output from the identified use cases. The TU application module interprets the connected aggregate load data and assesses the load condition based on load percentage above nameplate rating and relative time duration at each overload state. When ambient, top-oil, and/or winding hotspot temperature is available, we can overlay the temperature data to characterize the overload condition.

The analytics uses a ranking system based on a calculated "severity index" to prioritize overloaded transformers. A severity index is assigned to transformers that have encountered an extensive overload state over the given analysis period. As overload conditions are not necessarily always an issue, the system's severity index calculation uses a weighting algorithm to only rank and classify noteworthy overload conditions. The weighting system uses a combination of analyzing load percentage above nameplate rating, duration at each percentage level, and system peak load data.

The primary factors used to analyze and characterize transformer overload are aggregate meter load percentage above nameplate rating and time duration at each overload state.

System Planning Analysis

Use cases: Annual and monthly planning and capacity analysis support

System Planning focuses on profiling and normalizing interval load data at different aggregation points at the substation and/or along the feeder. With the increased adoption of distributed energy resources, the ability to understand its impact to the load curve has become more critical for system planning purposes. The data available within SDG&E from the current project can be used to aggregate and correlate against the network topology to a common point. The common point can be at the substation and/or a strategic node along the feeder, such as a recloser. After the aggregation is complete, an appropriate algorithm can be configured to identify load anomalies (i.e., switching events, load transfers, etc.) and normalizes the data to generate a representative load profile. The normalization process incorporates historical load pattern, seasonal load trends, and weather data to fill atypical load behavior, as well as using DER load shape library to disaggregate between gross and net loads.

Voltage Analytics

Use cases: Voltage quality, compliance and planning. With the emergence of distributed energy resources, increased customer demand, and continued initiatives in energy efficiency programs, secondary voltage management has become a critical task for electric utilities. Voltage Management Analytics is designed to monitor, analyze, and identify voltage issues for individual meters, transformers, and/or the full feeder. The purpose of the approach is to characterize voltage profiles along the feeder and identify meter and transformer voltage violations as defined by ANSI C84.1 specifications. Voltage issues are summarized and presented using various tabular reports, charts, bar graphs, and geospatial views.

The approach can establish voltage profiles for any grid-connected device with available time series-based voltage data. Grid-connected devices include but are not limited to smart meters, transformers, line sensors, capacitor banks, and line regulators. The algorithm uses a ranking system based on a calculated “severity index” to prioritize voltage performance relative to each transformer based on the voltage. measurements from connected meters. A severity index is assigned to transformers that have meters that have experienced a voltage violation (+/- 5% from nominal) over the given analysis period. To eliminate noise and excessive flagging of voltage violation anomalies, the severity index calculation uses a weighting algorithm to only rank and classify noteworthy voltage violations. The weighting system uses a combination of analyzing voltage magnitude, duration of voltage violation, frequency of violation, and coincidence violation between neighboring meters.

Voltage Management

Use cases: Asset management, capacity planning and additional analytics for AMI outage events

The AMI Outage Exception Analytics focuses on analyzing real-time outage exceptions received from meters and SCADA assets. Given the value of real-time outage notifications, system operators can be better equipped to utilize this data to improve operational efficiency and response time to outages. The algorithm processes the outage exceptions and uses a series of steps to confirm the outage, time bound the outage, quantify impacted customers, and identify a fault perimeter location.

PART IV

Part IV captures the results of the internal methodology executed by SDG&E personnel and describes the demonstration based on publicly available studies.

Part IV List of Illustrations

Part IV List of Tables

Part IV List of Acronyms

Acronym	Acronym Description
AMI	Advanced Metering Infrastructure
DER	Distributed Energy Resources
EPIC	Electric Program Investment Charge
EV	Electric Vehicle
GIS	Geographical Information System
L-L	Line to Line (phasing)
L-N	Line to Neutral (phasing)
MDMS	Meter Data Management System
O&M	Operations and Maintenance
OMS	Outage Management System
Phase ID	Phase Identification (meter to phase connectivity)
RFI	Request for Information
RFP	Request for Proposal

Acronym	Acronym Description
SCADA	Supervisor Control and Data Acquisition
SDG&E	San Diego Gas and Electric Company

1.0 Overview

The purpose of this internal methodology was to assess and demonstrate pre-commercial analytical approaches to phase identification to enhance utility system operations. Unlike the methodologies in Part II and Part III, this methodology focused on the internal effort by SDG&E personnel to identifying endpoint phasing based on publicly available studies. No work was done on meter-to-transformer mapping in this pre-commercial demonstration.

2.0 Methodology Approach

A single use case was demonstrated – analytic phase identification. This involved making predictions for the meter-to-phase connectivity within a feeder by using an internally developed algorithm based on the research and results in references, (Wenyu Wang, 2016) and (Roelofsen, 2018). On a feeder, electricity is typically distributed using three powered lines. Each line has a different phase of alternating current. Often these three phases are labeled A, B, and C. In between the powered distribution lines and residential electric meters, transformers are used to reduce voltages to operating levels. There are many ways to wire transformers between the power distribution lines. The result is the low voltage wires coming from a single-phase transformer can transmit electricity in one of six possible phases (A, B, C, AB, BC, AC), depending on the wiring configuration of the transformer. These phases are split into two groups. The L-N phases occur when the transformer is wired between a powered distribution line and a neutral line (phases A, B, and C). They conduct electricity with a phase corresponding to the phase of the powered line. The L-L phases occur when the transformer is wired between two powered distribution lines (phases AB, BC, and AC). They conduct electricity with a phase corresponding to the difference between the two powered distribution lines. Utilities typically keep track of the transformer to phase connectivity because all the meters connected to a single-phase transformer share the same phase. For this use case, however, meter-to-phase connectivity is predicted. The primary reason for this is the meter-to-transformer connectivity is also in question. Accurate meter-to-phase connectivity is sufficient for use in phase balancing. Meter-to-phase connectivity can also be used to cross-validate meter-to-transformer connectivity. Another reason that meter-to-phase connectivity is predicted, and not transformer-to-phase connectivity, is that voltages are not metered on the transformers.

2.1 Software Requirements

The internally developed phase clustering algorithm uses Python 3 for circuit analysis and the Julia Programming Language for voltage data analysis. Appendix A is provided as pseudocode to trace the logic of the algorithm. Voltage data is stored and preprocessed in a local SQLExpress instance. Results from the clustering algorithm and voltage data are displayed in a Power BI report.

2.2 Supporting SDG&E Infrastructure and Data Requirements

The internally developed clustering algorithm requires data found in the SDG&E OSI PI time series database, the SDG&E ESRI GIS system, and the SDG&E Engineering Data Warehouse.

The algorithm requires a voltage data extract from the OSI PI system containing five-minute interval Volt Hour readings over a time range. These data are stored in a relational database and used by the main algorithm written in Julia. The data are normalized to a per-unit voltage value based on nominal voltage. Meters with long periods of stale or missing data are removed from the analysis.

From the GIS system, an extract is pulled that contains data for service transformer and conductors in the GeoJSON format (GeoJSON, 2021). The attribute data from these sources are analyzed in the Python circuit tracing script to identify single phase branches in the circuit.

From the engineering data warehouse, a metadata extract is pulled which is used to map meter IDs to service transformer IDs. These data are stored in a relational database and joined with the voltage data.

2.3 Execution of Demonstrations

The algorithm used is a k-means constrained clustering algorithm. A k-means clustering algorithm is defined by (Pedamkar, 2020) as an unsupervised learning method that uses an iterative process in which the datasets are grouped into k number of predefined non-overlapping clusters or subgroups, making the inner points of the cluster as similar as possible while trying to keep the clusters at distinct space, it allocates the data points to a cluster so that the sum of the squared distance between the clusters centroid and the data point is at a minimum. At this position the center of the cluster is the arithmetic mean of the data points in the clusters.

The k-means algorithm is enhanced by generating constraints for the circuit programmatically using a GIS extract. The program starts at a chosen structure ID and recursively follows GIS conductors based on structure IDs. The program marks each conductor segment with a group ID. The algorithm reuses the last group ID only if both conductors are single phase and there are no multi-phase conductors attached to the structure. The program then outputs a mapping of transformer IDs to group IDs. The constraint data is then fed into the k-means clustering algorithm. Python and Julia pseudocode is contained in PART IV, Appendix A.

3.0 Results Discussion

3.1 Methodology Limitations

The internally developed phase clustering algorithm was designed to give the team a baseline metric of results accuracy using simple time-series clustering. Missing features of the internally developed solution compared to the vendor products are important to consider before looking at the accuracy of the results. The two main limitations of this algorithm are 1) the results output is provided as “phase groups” rather than “phase IDs” and 2) the analysis is currently restricted to single-phase, line to neutral meters.

The first limitation could likely be overcome by bringing in time series bus voltages and SCADA device voltages. After calculating a time series correlation coefficient between each phase group voltage and known phase voltages, a map between the predicted phase group and the actual phase ID can be created. With reasonable confidence in the existing GIS data, identifying phase IDs could also be accomplished by mapping the groups to the IDs that result in the least mismatched data. For demonstration purposes, this limitation was overcome using a manual analysis step.

The second limitation requires a more detailed understanding of the GIS data to ensure properly created constraints for meters electrically connected to more than one phase. The same clustering algorithm could then be run against the line-to-line meters to group them.

3.2 Results

The accuracy of the clustering algorithm for single phase meters on Feeder A and Feeder B was 72.5% (190/262) and 95.5% (741/776) respectively. Table 1 and 2 below provide the breakdown between predicted phase and true phase for each feeder.

Table 1. Feeder A Predicted vs. True Phase

Prediction Phase	True Phase	Count of Prediction
A	A	42
A	B	2
A	C	31
B	A	4
B	B	94
B	C	11
C	A	18
C	B	6
C	C	54
Total		*262*

Table 2. Feeder B Predicted vs. True Phase

Prediction Phase	True Phase	Count of Prediction
A	A	235
A	B	11
A	C	3
B	A	1
B	B	269
B	C	0
C	A	13
C	B	7
C	C	237
Total		*776*

When viewing the field confirmed phasing from Feeder A, it is clear that the algorithm struggled grouping A and C phase meters because of the similar voltage signature of the two phases. The reason for this can be seen visually when comparing Figure 1 and 2 below. Feeder A phases are much more tightly coupled than Feeder B phases.

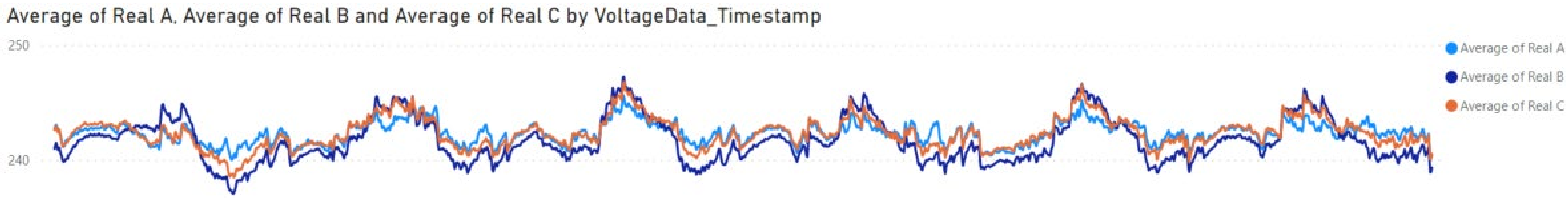


Figure 129. Feeder A Confirmed Phase Groups from 10/21/2018 to 10/26/2018

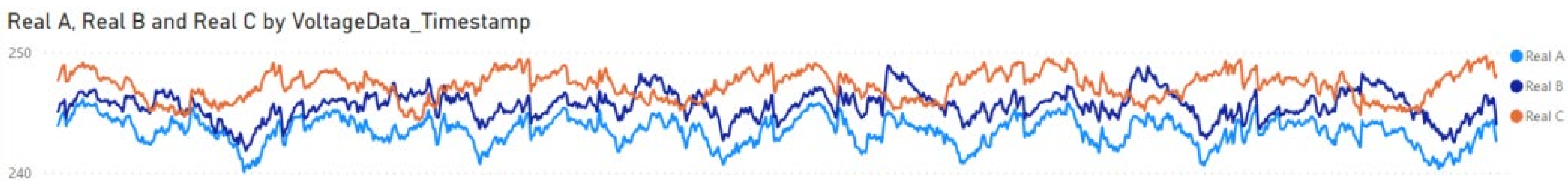


Figure 2. Feeder B Confirmed Phase Groups from 10/21/2018 to 10/26/2018

When running the algorithm, a metric is calculated indicating how consistently the meters were placed into the same bucket through multiple time ranges. For Feeder B, the consistency was 96.0%, while for Feeder A the consistency was only 84.8%. A confidence metric calculated based on the average Pearson correlation coefficient between each meter and each group it is not a member of, would also be a good indication of confidence in prediction accuracy. Meters that have close voltage profiles to other groups on average indicate the clustering algorithm is probably not a good choice for phase identification on a circuit.

4.0 Findings

Lessons Learned

The internally developed phase identification algorithm provided significant insight into the implementation of a simple, scalable solution for phase ID. One of the main lessons learned from this proof of concept is that a simple k-means clustering approach can be effective at phase ID in certain circumstances. Analysis of the results also indicates that it is possible to use confidence metrics from the results to decide whether voltage groups are unique enough to effectively cluster meters based only on voltage readings. Lastly, the results have sparked ideas on improving accuracy and confidence with different data preprocessing.

The difference in accuracy between the two circuits indicates that constrained k-means clustering is very effective in grouping meters within circuits that have a large sample size of meters and have distinct voltage signatures for each phase. For well suited circuits, accuracy in the mid-90% range can be achieved with this methodology. If changes to the GIS phasing data are only made in cases where the meter voltage signature is very similar to its group voltage signature while being relatively far from the other group voltages, confidence would be very high that the GIS model is being improved.

As discussed in the results section, one of the important findings from this proof of concept is there are circuits for which clustering is not as effective. In the case of Circuit A, there was difficulty in grouping meters between A and B phase because their voltage signatures were very similar. More detailed confidence metrics must be calculated with the results and confidence thresholds established so that phasing information isn’t changed to the wrong value.

Developing the phase clustering algorithm and analyzing the results have also brought forth different ideas on improving its accuracy. There are additional ways to identify constraints based on the GIS model that can be applied to the algorithm. By increasing the number of meter groupings, single meter spikes average out and the results are improved. There are also likely meters that can be guaranteed to not belong to the same phase based on the GIS model. These additional restrictions could improve performance of the analysis and improve accuracy. In addition to working on more GIS model analysis, improvements can be made to the algorithm by better selecting a time window to run the algorithm against. Depending on the time of year, weather, and many other factors the true phasing can vary in similarity. With a long time range of voltage data available, the algorithm can be run multiple times and the results with the most distinct phase characteristics can be used. The lessons learned from this process are valuable findings that can be used when analyzing an in-house developed phase identification algorithm or a vendor product using a similar method.

5.0 Conclusion

The internally developed phase identification algorithm has proven to be a very good baseline for which other vendor products can be compared. Keeping all preprocessing and GIS analysis done programmatically means the algorithm is easily scalable to all circuits without extensive cost. By understanding the shortcomings of the developed method, the team better understands where similar unsupervised methods may have accuracy issues. Analysis of the two circuit results has shown the importance of developing metrics and thresholds related to confidence of the groupings. It is also clear that more effort needs to be invested into static analysis of the GIS model to improve accuracy on circuits that are not as well suited to time series voltage clustering.

6.0 References

Reference	Document Title
1	Wenyu Wang, Nanpeng Yu, Brandon Foggo, and Joshua Davis, “*Phase Identification in Electric Power Distribution Systems by Clustering of Smart Meter Data”*, 2016 15th IEEE International Conference on Machine Learning and Applications (ICMLA).
2	Pjotr Roelofsen, 2018, “Time series clustering”, Vrije Universiteit Amsterdam Faculty of Science, De Boelelaan 1081a 1081 HV Amsterdam, https://www.math.vu.nl/~sbhulai/papers/thesis-roelofsen.pdf
3	Priya Pedamkar, 2020 “K-Means Algorithm”, EDUCBA, https://www.educba.com/k-means-clustering-algorithm/
4	Wikipedia contributors. (2021, November 3). GeoJSON In *Wikipedia, The Free Encyclopedia*. Retrieved 11:59, December 5, 2021, from https://en.wikipedia.org/wiki/GeoJSON

Part IV Appendix A – Python and Julia Algorithm Scripts

Note – This pseudocode cannot be run as-is, rather, it provides the logic that can be used in other programming languages and was derived from the publicly available studies - (Wenyu Wang, 2016) and (Roelofsen, 2018).

Python Circuit Tracing Algorithm

```
PROCEDURE MAIN

SET firstStructureID to the structure ID where the tracing should start on the circuit

SET conductors to the contents of the parsed conductor JSON file

CALL generateConstraints function with firstStructureID, conductors

SET transformers to the contents of the parsed transformer JSON file

FOR transformer in transformers

  SET allNodes to a list of conductors upstream or downstream from the current structure

  IF allNodes have matching groupIDs THEN

    APPEND transformer.ID to an array stored in groupData[groupID]

  ENDIF

ENDFOR

OUTPUT JSON file with the transformerID to groupID mapping


PROCEDURE generateConstraints

INPUT currentStructureID, conductorMap, branchID DEFAULT 0

SET conductor to conductorMap[currentStructureID]

SET conductor.branchID to branchID

SET connectedNodes to a list of conductors with IDs matching conductor.UPSTREAMSTRUCTUREID and
conductor.DOWNSTREAMSTRUCTUREID

SET maxPhases to the maximum number of phases designated to conductor and connectedNodes

FOR node IN connectedNodes

  CONTINUE IF node.branchid is set

  IF maxPhases is 1 THEN

    CALL generateConstraints with node.ID, conductorMap, branchID

  ELSE
```

CALL generateConstraints with node.ID, conductorMap, getNextBranchID()

ENDIF

ENDFOR

Julia Time Series Voltage Clustering Algorithm

PROCEDURE **MAIN**

SET data to a DataFrame containing columns MeterID, Timestamp, Vh, and TransformerID for a 3 month time period

SET constraints to the output data from the circuit tracing algorithm

JOIN data with constraints adding a new groupID column to data

SET dataGroup to data grouped by the id column

SET windowVotes to a zero matrix with dimensions (length(groupID), 3)

SET windowBreaks to a list of evenly spaced ranges for which the clustering algorithm will operate on

FOR windowRange IN windowBreaks

SET analysisDF to an empty dataframe

Iterate through each group in dataGroup and append the subset of data to analysisDF

SET groupedAnalysisDF to analysisDF grouped by the groupID column

CALL cluster WITH groupedAnalysisDF, 3, length(windowRange)

Calculate which permutation of the returned groups aligns most closely with windowVotes

Apply the permutation to the returned groups and add the votes to windowVotes

ENDFOR

OUTPUT a CSV file with each meter ID and the prediction containing the most votes from its row in windowVotes

PROCEDURE **CLUSTER**

INPUT groupedDataFrame, clusterCount, seriesLength

SET estimatedClass to a random selection of 1:clusterCount of size length(groupedDataFrame)

SET iterationNumber to 0

WHILE true

INCREMENT iterationNumber

Calculate the average voltages for each estimatedClass group at each time in the analysis window

FOR gdf in groupedDataFrame

Calculate the sum of the Pearson distance between each group member and each cluster group

SET estimatedClass[groupIdx] to the group with the smallest Pearson distance

ENDFOR

IF no group changes were made then break out of the loop

END WHILE

RETURN estimatedClass

PART V

PART V summarizes Module 2 project outcomes.

Part V List of Tables

1.0 Module 2 Findings

All three methodologies agree that automatic phase identification is achievable at acceptable levels of accuracy using data from only two meters per transformer, as the project module sought to confirm. Meter-to-transformer connectivity, however, proved less precise with demonstrations revealing added complexity when the use case included correction to meter-to-transformer mismatches. A summary of findings by methodology is provided in Table 1.

Table 1: Summary Findings by Methodology

	Methodology A		Methodology B		Internal Methodology	
	Circuit A	Circuit B	Circuit A	Circuit B	Circuit A	Circuit B
Accuracy Phase ID	98%	97%	83%	92%	72.5%	95.5%
Accuracy Meter-to-Transformer (two connected meters)	82%	79%	65%	89%	NA	NA
Accuracy Meter-to-Transformer (three connected meters)	95%		NA		NA	
Key Challenges	For meter-to-transformer mapping, a sufficient number of connected meters is necessary. At two meters per transformer, it is possible to detect the presence of a single error, but it is not possible to correct that error without introducing more errors into the system.		Quality of source data and data availability impacts accuracy results		Phase ID limited to line to neutral phasing. Line to line phase identification will require future research.	
Lessons Learned	For phase ID, the voltage correlation solution using data for two meters per transformer achieved accuracies on par with those of field verifications More tests are required to determine if voltage data for		The demonstration proved that using data analytics to automatically identify the phase of meters is possible. For meter-to-transformer, accuracy of the prediction correlated with the availability of AMI data as		The clustering algorithm can be effective at phase ID. Clustering is not as effective where meters have similar voltage signatures (A and B phase).	

	Methodology A		Methodology B		Internal Methodology	
	Circuit A	Circuit B	Circuit A	Circuit B	Circuit A	Circuit B
	two meters per transformer can be used to accurately predict and correct meter-to-transformer connectivity on a given feeder		demonstrated in circuit A which had only 13% coverage of voltage data resulting in lower accuracy compared to Circuit B.			
Future Considerations	To achieve data collection on every meter on a feeder, further research into the maximum network capacity is recommended. If it is the case that longer voltage intervals could reduce network traffic, then it is possible that the optimal data collection scenario on the given network requires longer voltage intervals.		Extension of the utilization of AMI and SDADA data for operational purposes beyond the Module 2 project scope (provided in PART III, Appendix B).		Use of different data pre-processing techniques for improving accuracy and confidence levels.	

2.0 Updated Value Proposition

If commercially adopted, each of these methodologies could improve workforce safety by reducing the frequency at which SDG&E employees and contractors must field verify phase ID, hence lowering the potential of hazard. In cases where manual verification is still needed, such as in situations where correct connectivity information affects safety, better understanding of the circuit distribution will help to streamline the process. The data analytics approach could also increase the safety for SDG&E customers by enhancing grid reliability.

Added value of the approach is improved reliability and power quality and improved performance of the distribution system by enabling better phase balancing and ensuring transformers are not over or underloaded by using an analytical approach. Accurate connectivity models also support a growing body of advanced data analytics for solving problems from load management issues with electric vehicle (EV) to outage management.

By reducing system electrical losses and enhancing grid efficiency, accurate connectivity models will help reduce the need for electric generation, thereby also reducing greenhouse gas emissions.

If operationalized, this project will lead to more efficient, reliable, and safe electric power, with lower cost and higher quality. All of these are consistent with the objectives of the EPIC program and provide value to SDG&E's customers.

3.0 Commercialization

The following discussions offer guidance and cost estimates for commercialization of the vendor and internally developed methodologies.

3.1 Methodology A

Commercial adoption of the system used in this methodology should include ongoing analysis of phase identification and meter-to-transformer on a regular basis. This analysis is important to ensure utility enterprise systems that increasingly rely on these data are correct and up to date as new customers come online, crews perform maintenance, and proactive activities like phase balancing and feeder reconfigurations occur.

Commercial cost components:

1) Data loading package, and initial endpoint configuration and subscription to AMI headend system. This is a one-time cost to set up a service to load initial and ongoing AMI measurements.
2) One-time cost: approximately $100,000
3) Support services for systems integration and data validation
4) Annual services contract: approximately $75,000 - $120,000
5) Software as a Service (SaaS) subscription to cloud-based analysis software, including web-based user interface and reporting: Annual SaaS subscription approximately $700,000 - $1,200,000
6) Ongoing analysis of phase identification and meter-to-transformer connectivity
7) Internal resources

3.2 Methodology B

Strong emergence of data analytics, information technology (IT) and operations technology (OT) convergence is helping utilities capitalize inherent value of data aggregated and maintained in AMI, SCADA, GIS, enterprise asset management (EAM), and customer information systems (CIS). The demonstrated methodology highlighted the commercial elements of various components for consideration. Table 2 below highlights the commercial implications and consideration for full-scale implementation of this methodology.

Table 2. Methodology B Commercial Considerations

Project Component	Commercial Implications	Recommendations and Opportunities
Technology platform to support data ingestion, processing, and aggregation	SDG&E to consider investment in base technology platforms that support enterprise grade ETL, hosting the solution in a big	Commercial options exist for either hosted services as demonstrated in the project or investment in the full license of

Project Component	Commercial Implications	Recommendations and Opportunities
	data platform and visualizing in an intuitive interface	the platform within the SDG&E on-premises environment.
Proven algorithm that can be configured, improved, and include visualization of results	SDG&E to consider proven algorithm that can be easily configured and scaled for their service territory	Market offers configurable algorithms that can be deployed on-premises or as demonstrated through this project in a SaaS model.
Prepare, validate, and define data transport to SDG&E's source data (AMI, SCADA, GIS etc.)	SDG&E to plan to build the data bridges to continuously move data to the platform solution	A recommended approach is to plan for professional services to build scalable bridges to ingest data from the source system. Ideally, the solution chosen for the automated mapping will offer the capabilities for SDG&E's consideration.
Address gaps in data quality that may limit the accuracy of automated approach	SDG&E to carefully evaluate the source data quality that might prevent the required level of accuracy for automated mapping. This is a key component that should be budgeted and addressed effectively.	Level of data quality and source of the issue drives the cost of resolution. SDG&E should also carefully consider the critical data gaps vs. non-critical in consultation with the chosen partner solution for optimal accuracy in prediction. SDG&E should also evaluate the needs for deploying sensors at bellwether asset locations to address the gaps in voltage data.

3.3 SDG&E Internally Developed Methodology

The unsupervised nature of the internally developed algorithm allows scale up of phase identification to all circuits for a relatively low cost. All the steps taken during the data pre-processing phase would be trivial to automate for any number of circuits. An estimated 370 hours of work with an internal developer, GIS analyst, and engineering resource would be sufficient to automate the current algorithm to run for all circuits.

In the results discussion in Part IV, two limitations were discussed that would need to be addressed for commercialization. The first limitation of the groupings to phase translation would require more collaboration between engineering groups and IT. If SCADA data or a static circuit analysis tool proves sufficient, this solution would take an estimated 90 hours.

The second limitation to overcome with this solution is to include line to line and polyphase meters in the analysis. This could be overcome easily with some additional analysis of the circuit and meter metadata. Incorporating this into the existing algorithm would take an estimated 160 hours.

Prior to commercialization, some additional postprocessing metrics would be required to gauge confidence in the results of the clustering algorithm. The time series clustering algorithm works much better in circuits with a greater distance, or differentiation between the voltages of each group. Because of this, it is important to provide additional confidence metrics to get an idea on when the algorithm might have done a poor job at grouping meters. These simple calculations would take an estimated 10 hours of work.

The last requirement prior to commercialization is to enhance the results display to allow for more detailed analysis of the algorithm output. A Power BI and ArcGIS map layer would provide out of the box functionality to display the results geospatially with added context from existing circuit and service transformer layers. Enhancements to the result dashboard would take an estimated 120 hours of work with out-of-the box solutions although this cost could grow if a custom application with alternate functionality is required.

In total, the enhancements and changes needed for an adequate internally developed phase identification solution would start at an estimated 370 hours of work with an internal developer, GIS analyst and engineering resource. A project champion and funding sources would need to be determined if this methodology is pursued.

4.0 Tech Transfer Plan

The results of this project will be disseminated throughout the industry in several ways.

SDG&E Website

This comprehensive final project report is the main tech transfer documentation for the project. All EPIC final project reports are posted to the SDG&E website at: https://www.sdge.com/epic. The website also includes annual updates that were made over the life of the projects. These documents are also filed with the CPUC.

EPIC Symposium

The project results will be shared with California Investor-Owned Utilities through the annual EPIC symposiums. During these meetings, information on various EPIC projects is shared with the personnel from the other IOUs in the state.

Industry Conferences and Publications

SDG&E personnel worked with the product vendors to develop presentation material outlining the results of this report. These

presentations will be offered, as may be appropriate, for inclusion at industry conferences such as DISTRIBUTECH, IEEE conferences, Utility Week, Grid Modernization Forum, and others. Papers may also be submitted to industry publications, such as IEEE Transactions.

5.0 Recommendations

5.1 Transition for Commercial Use

Based on the findings and results in this demonstration, phase identification and meter-to-transformer mapping are not ready for commercial use with the given constraint of two meters per transformer. While phase identification has shown promising results with this constraint, meter-to-transformer mapping has not. To achieve higher levels of accuracy for meter-to-transformer mapping, this constraint must be removed and data from as many meters as possible used in calculations.

5.2 Implementation Recommendation

Advancements in machine learning, advanced data mining, and artificial intelligence coupled with reduced data storage costs and improved network throughput have created numerous opportunities to use AMI data beyond the use case of meter reading and billing. The successful use case in this demonstration, analytical based phase identification, is just one example of this, but there are many more. Pursuing only this singular use case would be an inefficient use of resources when additional valued could be derived from the data collected. The key recommendation for this study is to identify additional use cases that use AMI data, and then to pursue an application or suite of applications that can fulfill them. This will require further investigation and coordination with operations personnel. At a minimum, the following high-level activities should be pursued:

Use Case Development/Business Case

Identify a core team of human resources (internal staff supported by consultants) with expertise in various areas of business operations. These areas may include distribution grid operations, distribution planning, AMI operations, Electric Regional Operations, and others. Conduct a brainstorming session to determine various use cases that could potentially use AMI data as its source. Sample use cases are listed in Part I, Section 6.1.2. Part and parcel to identifying the use cases ensuring that operational requirements are identified for each use case. This is where the minimum acceptable accuracy for each use case must be identified in addition to other functional and non-functional requirements. From these use cases, a business case must be developed that clearly identifies the benefits and the associated cost.

Request for Information/Request for Proposal

Once the use cases are identified, further investigation will be required to determine the availability of products or services that can satisfy each use case. Steps to accomplish this task include requirements gathering (beyond those that are identified for each use case); preparation and submission of the

Request for Information (RFI) or Request for Proposal (RFP); evaluation of the vendor/service provider responses; and finally, vendor selection.

Future potential use cases have a wide variety of organizations across the enterprise that will benefit from implementation. However, solving the needs of all potential users may be too large of an endeavor. The project team therefore recommends limiting use cases to organizations that perform planning functions and grid modernization functions. It is recommended that the stakeholder business units in SDG&E that served on the team for this EPIC project, define and implement an action plan to pursue the steps outlined above.

EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-3, Project 4**
Project Name	**Safety Training Simulators with Augmented Visualization**
Module Name	**Module 1, Focused Patrol Simulator**
Date	**December 31, 2021**

Attribution

This comprehensive final report documents the work done in this EPIC activity.

The project team for this work included the following individuals, listed alphabetically by last name.

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EXECUTIVE SUMMARY

Project Objective

The objective of SDG&E's EPIC-3 Project 4 was to demonstrate and evaluate augmented reality applications for field focused design, operations, and asset monitoring and management solutions in utility power systems. The project was split into two modules. Module 1 was center on focused patrol for the benefit of operator trainees. Module 2 was centered on safety procedures for underground distribution field work. Module 1 is the focus of this document and Module 2 is covered in a separate report. Both are available on SDG&E's public website.

This report covers the work done in Module 1. The objective of Module 1 was to conduct a pre-commercial demonstration of a functioning fault location system that was utilized to create a training stimulator for electric distribution system operators and other prospective users.

Approach

When outages occur on the distribution system, there are many steps required to correct the underlying cause and restore power. The typical restoration process stages are 1) Detection, Prioritization and Queuing; 2) Dispatching & Patrolling; and 3) Restoration Plan & Restoring the Service. The goal of this demonstration project is to investigate additional tools that can be used to optimize and reduce the "Dispatching & Patrolling" times.

A pre-commercial demonstration system was constructed that included a replication of the commercial Advanced Distribution Management System (ADMS) environment with new software modules and integrations with new sensors including: 1) Wireless Fault Indicators (WFI), 2) Advanced Metering Infrastructure (AMI) Low Voltage (LV) alarms, 3) Weather Data, 4) Advanced Protective Relays, and 5) Phasor Measurement Units (PMU)s.

The most valuable data sources were incorporated into training scenarios that can be used to train system operators on how to use the data to direct field crews to patrol the most likely faulted locations first. And finally, the training scenarios were demonstrated to a team of experienced system operators and trainers to review and critique the findings and potential training scenarios.

Recommendations

The following recommendations are determined based upon the analysis done as part of this project:

- Establish and maintain a permanent Training Simulator in a non-production environment and mirror the production system
- Add new data sources to the production system (weather data, AMI low voltage alarms, Wireless Fault Indicators)
- Maintain a regular training program for the operators, reviewing scenarios analyzed during this project
- Continue to investigate new scenarios and new data sources (including Phasor Measurement Unit (PMU) data) in an Innovation Lab environment, as a continuous improvement practice to feed the Training Simulator with new valuable scenarios

Conclusions

In order to incorporate existing multiple new and enhanced data sources that can assist in identifying the most likely locations of faults to reduce restoration time, additional training for system operators is required to properly interpret the new data sources. In addition, new User Interface (UI) configurations can assist in limiting the clutter caused by the presentation of too much information. These user interface enhancements can reduce the amount of training required for operators to properly interpret the additional data.

The Training Simulator provides a controlled environment to test scenarios with current and future sensor data. With the addition of more devices and more data, operators can be overwhelmed with information that is difficult to interpret and utilize. Analyzing data, simulating scenarios and training in a non-production system provides the foundation to build a process before additional data is displayed in a production system. Additionally, the training simulator enables operators to be trained on relatively rare and numerous unique fault situations.

Overall, the recommendation is made for commercial adoption of this technology solution. It is recommended that the stakeholder groups within SDG&E who participated in this project pursue commercial adoption by organizing a commercialization team and appointing one key stakeholder group to lead the effort. A commercial adoption plan should be developed as a next step.

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List of Acronyms

Acronym	**Acronym Description**
AC	Alternating Current
ADC	Analog to Digital Converter
ADMS	Advanced Distribution Management System
APR	Advanced Protective Relay
AMI	Advanced Metering Infrastructure
ARP	Auto Reclose Process
API	Application Program Interface
CAIDI	Customer Average Interruption Duration Index
CEV	Compressed Event Report
COMTRADE	Common Format for Transient Data Exchange for power system (COMTRADE)
CPUC	California Public Utility Commission
DA	Distribution Automation
DER	Distributed Energy Resource
DOE	Department of Energy
DSO	Distribution System Operator
EAM	Enterprise Asset Management System
EMS	Energy Management System
EPIC	Electric Program Investment Charge
ETS	Electric Troubleshooters
EV	Electric Vehicle
FCI	Fault Current Indicator
FLA	Fault Location Analysis
GIS	Geospatial Information System

Acronym	Acronym Description
HV	High Voltage
HMI	Human Machine Interface
IEEE	Institute of Electrical and Electronic Engineers
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
NMS	Network Management System
OMS	Outage Management System
OTV	Onramp Total View
PDC	PMU Data Concentrator
PDO	Predicted Device Outage
PMU	Phasor Measurement Unit
PQ	Power Quality
PQM	Power Quality Meter
PSO	Predicted Service Outage
RDO	Real Device Outage
RMO	Real Momentary Outage
RTAC	Real Time Automation Controller
SA	Substation Automation
SDG&E	San Diego Gas and Electric
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
TOU	Time of Use
WFI	Wireless Fault Indicators

SECTION 1. INTRODUCTION

Project Objectives

The objective of SDG&E's EPIC-3 Project 4 was to demonstrate and evaluate augmented reality applications for field focused design, operations, asset monitoring, and management solutions in utility power systems. The project demonstrated the ability of the latest simulator technologies to train utility industry personnel on safety-related issues, including electric potential zones and grounding techniques associated with construction work practices. Capabilities demonstrated included the utilization of augmented reality tools to visualize and provide rich contextual information at the point of work.

The project was divided into two modules. Module 1 conducted a pre-commercial demonstration of a functioning fault location system that was utilized to create a training stimulator for electric distribution system operators and other prospective users. The system simulator integrated input from multiple sources that utilize different technologies. This document is the comprehensive final report on Module 1.

Module 2demonstrated the use of virtual-reality visualization tools to aid in training field employees in safe practices for working in situations where there is the possibility of unexpected hazardous levels of electric potential. A separate final report has been prepared for Module 2 and is posted on the SDG&E EPIC internet site.

Issues and Policies Addressed

In the context of electric utilities and wildfire risk, improving operator situational awareness is a key aspect of safe, successful real-time operations. This addresses a major California Public Utility Commission (CPUC) focus.

The 2018 California Senate Bill 901 requires all utilities to create an annual wildfire mitigation plan [1]. The Office of Energy Infrastructure Safety approves the plans from each utility, and they are then certified by the CPUC.

Grid Operations and Protocols are a required element of the wildfire mitigation plan and identifies risk and mitigation efforts. This project provides insight into new technologies and training techniques that could potentially be deployed to further mitigate wildfire risks and improve customer and field personnel safety. Enhancing the training experience for operator trainees will improve the pipeline of new operators and help to ensure adequate staffing for real-time operations, keeping operators rested and fresh as they begin each shift.

Project Focus

The focus of the project was to present actionable data from disparate sources to system operator trainees, in a unified manner, for improved situational awareness, and improved safety and reliability outcomes. The more reliable the system becomes, the greater the public safety.

Technical Issues

A Distribution System Operator (DSO) is responsible for planning and executing operational functions associated with an electrical distribution system. DSOs operate and maintain the local distribution area, separate from the transmission operator, and are responsible for providing a highly safe and reliable distribution service.

The DSO strives to improve the quality of the service and the safety of the public and field crews. DSO also work to minimize the overall Customer Minutes Interrupted (CMIs) and shorten the time that is required to restore an outage.

Currently, there are multiple tools available for utilities to manage the reliability of the distribution system including:

- Substation Automation (SA) to monitor voltages, currents, and control device operations inside distribution substations.
- Distribution Automation (DA) monitors and automatically controls devices along the distribution circuits, such as switches, reclosers and auto-sectionalizers.
- Outage Management System (OMS) is used to manage the restoration process; the process is triggered by a customer reporting an outage via a phone call, or other electronic reporting methods through a website, text message, mobile application, etc.
- OMS tied with an Automated Metering Infrastructure (AMI) solution can automatically identify the meters that are out and those that are restored.
- Distribution Supervisory Control and Data Acquisition (SCADA) that remotely monitors device operations and measurements at select points on a feeder and enables switchable devices to be opened and closed remotely.

There are several key performance metrics related to system reliability that all Load Serving Entities (LSEs) use to measure their performance and benchmark their current reliability against past performance and other utilities. The most used metrics are:

1. SAIDI (System Average Interruption Duration Index) – minutes of sustained outages per customer per year.
2. SAIFI (System Average Interruption Frequency Index) – number of sustained outages per customer per year.
3. CAIDI (Customer Average Interruption Duration Index) – is the average time required to restore service to a utility customer.
4. MAIFI (Momentary Average Interruption Frequency Index) – number of momentary outages per customer per year.

These four metrics are used in the electric utility industry to measure its reliability and quality of its service at the distribution system level as defined in The Institute for Electrical and Electronic Engineers (IEEE) Guide for Electric Power Distribution Reliability Indices (IEEE Standard 1366).

Reducing the amount of time to perform restoration has a direct impact on customer service reliability as measured by SAIDI and CAIDI. It is important to understand the overall restoration process and the individual steps that are part of the process so that it can be systematically analyzed and improved.

The common or typical restoration process steps are explained in *Table 1 Outage Restoration Steps*.

Table 1 Outage Restoration Steps

Stage	**Time Steps**	**Description**
Detection, Prioritization and Queuing	T0	Start of the outage
	T1	Outage “Ticket” generation in OMS
	T2	Outage created and prioritized in OMS
Dispatching & Patrolling	T3	Electric Troubleshooter (ETS) crew dispatched
	T4	ETS crew arrives on-scene

Stage	Time Steps	Description
	T5	ETS crew completes patrolling and troubleshooting of outage
Restoration Plan & Restoring the Service	T6	ETS Crew performs partial or full restoration, if possible
	T7	Additional crew(s) assigned in OMS (if required)
	T8	Additional crew(s) dispatched
	T9	Additional Crew arrives on-scene
	T10	Crews perform full restoration

The relevant times in the process are described in further detail in *Table 2 Outage Process Time Steps*.

Table 2 Outage Process Time Steps

Time:	Outage Process Activity
T0	The time the outage begins, this is the time the outage is identified by customer calls, AMI, or SCADA.
T1	The time the outage is created in the Outage Management System (OMS).
T2	The outage priority will be analyzed based upon policies by dispatchers. This is the time that the outage is assigned a priority. Based upon priority, the outage may be queued behind other outages waiting for a crew to be available.
T3	This is the time ETS crew is actually dispatched to location of outage determined by OMS. Typically, this is the location of a protective device (i.e., fuse) that operated to isolate a faulted section.
T4	The time the ETS crew arrives on-scene at the location provided by the OMS.
T5	The time the ETS crew completes patrolling downstream of the protective device and identifies the actual fault location(s) and damage location(s); the outage cause is determined at this time.
T6	The time when ETS crew completes partial or full restoration (if possible). ETS crews are only able to restore certain types of outages that do not require multi-person crews or special equipment.
T7	The time additional crew(s) are assigned (if required). The crew(s) assigned are based upon the specific outage location, cause, and damage.
T8	The time additional crew(s) are dispatched to the location of fault and/or damage.
T9	The time the additional crew(s) arrives on-scene.
T10	The time of full restoration. This occurs after the additional crew(s) arrive. The crews may perform some step (partial) restoration to restore customers outside of the faulted and damaged area before addressing the fault, repairing the damage and performing the final full restoration.

This project investigated additional tools that can be used to optimize and reduce the “Dispatching & Patrolling” times. These “tools” used information from new sensor technologies to supplement current fault location analysis and provide additional fault location information before the patrolling begins. The proposed approach was to train operators to use computer systems to analyze and present information from new sensor technologies that can provide additional insight into the location and cause of the outage before the crew is dispatched, ultimately reducing the patrolling time required (T4-T5).

Project Scope and Benefits

The scope of this module was to demonstrate a functioning pre-commercial training simulator that can help instruct system operator trainees how to narrow the patrol or search location of a fault for a set of selected test circuits. This new training simulation platform was utilized to teach the system operators/trainees as well as other prospective users to recognize, understand, and utilize the signals provided by new sensor data sources, including an installed array of Wireless Fault Indicators (WFI's). The training was in conjunction with existing SCADA, WFI's, upgraded AMI functionality, and a revamped Advanced Distribution Management System (ADMS) with built-in algorithms. This scope was intended to enhance the ability to more quickly and accurately predict the region of a fault. The use of real-time data from the AMI was incorporated, along with advanced SCADA functionality (i.e., synchrophasors). Minimizing the duration of fault location process and allowing operators to dispatch fewer, more-focused field personnel more strategically to the scene was the scope of the project with the following targeted benefits:

- Safety to SDG&E's Personnel

  Because the training simulator is based on a more efficient approach for determining fault location and directing field personnel to the fault location, it inherently improves safety for field personnel, reducing their driving exposure especially into more rural areas and sometimes dangerous weather conditions. Nighttime operations will especially be improved.

- Safety for the Public

  The new training process and improved field equipment allows the operators to locate wire down events quicker, reducing public exposure to a potentially energized system. Any system that hastens service restoration inherently improves safety to the public, ensuring local infrastructure operates as intended (e.g., lighting, communications, water and sewer systems, traffic signals, and fire-fighting equipment), after faults of any kind cause service interruptions.

- Risk Reduction

  Since a fault location can be identified more quickly, and the correct personnel deployed with greater accuracy and speed to that location, it:

  - Enables the organization to be better prepared for the future by offering more measures to mitigate/decrease the risk of starting fires due to wire down or possibly other events, thus significantly reducing the overall risk that the company and its customers face as it relates to wildfires.

  - Reduces the need for test closures, which could make a more resilient utility by extending the life cycle of distribution equipment. Test closures into faults are extremely violent events and contribute to wear and tear on equipment. Reducing the frequency of test closures improves safety, reduces operating costs, and improves power quality.

- Reduced Cost

    - Focused patrol training allows for quicker fault identification, effectively reducing crew effort and therefore potentially reducing the overall System Average Interruption Duration Index (SAIDI) impact of outages, making the DSO more efficient. It will also increase customer satisfaction and reduce their exposure to wildfire-related issues and other risks associated with outages.
    - This training module naturally leads to process improvements, which allow a utility to do the same job with fewer resources (i.e., if the location of the fault is determined more quickly, personnel can be deployed to the location more quickly, and released from duty earlier so they can be assigned to subsequent tasks as needed).

- Improvements in Training Efficiency

    - Improved training outcomes in terms of training effectiveness and speed, student learning outcomes.

SECTION 2. APPROACH

The project started with a list of Use Cases and a proposed set of sensor data sources that would be used in the Training Simulator environment. During the set-up of the new Training Simulator environment, the use cases were reviewed, and information was gathered on the data sources. This initial data analysis and discussions with operators showed potential value from creating multiple fault location and detection scenarios, with and without new sensor data. A significant amount of time was spent analyzing the new data sources, comparing current fault location processes and identifying real situations where devices tripped or did not trip, as well as situations where faults occurred but were not detected. The analysis details are provided in Section 3 – Demonstration Development.

Fact Finding

The team reviewed and detailed the initial **seven use cases** that represented areas of focus. The use cases were developed based on the review of fault events. The use cases were prioritized based upon potential benefits and applicability to the focus of the project. The following lists the use cases in priority order:

- UC1: Wire Down
- UC2: Proactive Fault Detection
- UC3: Foreign Object in line
- UC4: Tree/Vegetation Contact
- UC5: Overload Mitigation
- UC6: Underground distribution
- UC7: Primary Voltage Customer Problem

Data from five new sensor types were used in the analysis

- Wireless Fault Indicators (WFI)
- Advanced Metering Infrastructure (AMI) Low Voltage (LV) alarms
- Weather Data
- Advanced Protective Relays

- Phasor Measurement Units (PMUs)

See **Appendix A** for the details of each of the Use Cases. The Demonstration Development section includes the detailed analysis performed on each new sensor type as well as the simulations and specified findings.

Potential Benefits Identification

At the beginning of the project, the targeted benefits identified in the project scope were reviewed with the detailed use cases. The process aimed to produce a list of potential benefits that would result from the commercial adoption of the demonstrated training solution in the EPIC-3, Project 4, Module 1, Focused Patrols of Distribution System Overhead Lines. These initial benefits identified were used as guide in the demonstration phase of the module.

Due to the intangible nature of this project (Staff Training), the plan was to document the current fault location process (establish the baseline) and compare how the training simulator helps train DSO's to improve the process of conducting fault location analysis. The benefits gained by the implementation of the training stimulator were the focus of this study.

This is supported by the findings from a Department of Energy (DOE) study in 2014 [2] from seven successful projects from the Smart Grid Investment Grant (SGIG) program across the US in five distribution operating companies. Similar fault restoration technologies that reduced outage durations found that significant process changes were required and that greater expertise in information technology, database management, and grid analytics necessitated new educational and training programs [2]. Leveraging these "lessons learned" from other utilities, the training simulator and associated training programs are necessary. The following fault location process was documented and referenced in determining the benefits defined in the scope of the project.

When an outage occurs, the DSO begins service restoration as soon as possible. Unless damage reports indicate where the cause is located, the DSO directly uses non-tripped fault targets (when available) from the distribution line SCADA site(s) to determine if a line segment is free of faults. For all other cases, and during the non-fire season outside of fire zones, as allowed by protocol, the location of faults is sometimes confirmed through test closure of the feeder breaker or service restorer. The current process not only diminishes the resiliency of the system by weakening it each time a test closure into a fault occurs, but also increases inefficiency in the work force. Given that multiple field personnel must arrive on scene before any testing occurs, the duration of the outage is prolonged with multiple electric troubleshooters driving from device to device. System operator practice also demands that individuals check in from the field on an outage, to be confirmed in the clear by company radio before any closure attempts are made, sometimes extending the time for ultimate restoration.

Reduced Cost

During the project, scenarios were developed in the training simulator using a copy of production data with and without the addition of new sensor data. Through the addition of new sensor data, it was apparent that reduced cost would result from the addition of new sensor data to the existing process with the appropriate training for the operators. Below is a list of the reduced cost benefits identified:

- Focused patrol training will allow for quicker fault identification, effectively reducing the patrol time required to find the fault location, isolate the fault and restore service more quickly. Faults often occur after normal work hours, and thus crew call outs to restore outages are often associated with overtime labor rates. Shortening the restoration will reduce overtime costs and can reduce the number of crews called to help patrol the line. During normal work hours crews will become more efficient in the restoration, allowing them to get more work done during their workday or shift.

- By using the training simulator to improve the fault identification process, faster arrival at the actual fault location reduces the duration of power interruption and the overall System Average Interruption Duration Index (SAIDI) impact of outages is reduced, improving reliability and reducing lost revenue.
- Using the training simulator will also increase customer satisfaction and reduce utility company exposure and costs associated with wildfire-related issues and other outage related risks.
- This training module will naturally lead to process improvements, which will allow a utility to do the same job with fewer resources (i.e., if the location of the fault is determined more quickly, personnel can be deployed to the location more quickly, and released from duty earlier, or assigned to subsequent tasks as needed).

Improvements in Training Efficiency

Focused Patrol reduces the overall time needed to accomplish the training of new operators.

Metrics

One outcome is the improvement in the ability to more easily simulate and configure the training simulator. This will result in improved student learning outcomes with greater improvements in operating practices that achieve the metrics of improved SAIDI and fewer test closures.

Pre-Commercial Demonstration

A pre-commercial demonstration system was constructed that included a replication of the commercial ADMS environment and new software modules listed below:

- Network Management System (NMS) – Network Management System is another name for an Advanced Distribution Management (ADMS) System.
- Outage Management System (OMS) – This is the module of the ADMS/NMS that is used to manage grouping of customer calls, AMI events and other inputs into logical outages, as well as support the prioritization of outage restoration, tracking of the progress of outages and the restoration processes.
- Fault Location Analysis – This is a module of the ADMS/NMS that is used to identify the location of an electrical fault. This is done based upon an electrical connectivity model combined with measured fault currents and electrical impedances of every element in the electrical model.
- Training simulator – This module of the ADMS/NMS that supports the development of scenarios and simulation of actual power system behavior for the purposes of training system operators.
- Power flow – The Power Flow module of the ADMS/NMS analyzes the electrical power flow and voltage profile of every element in the distribution system using available measurements, an electrical connectivity model, electrical impedances, and load information.
- SCADA adapter – The SCADA adaptor of the ADMS/NMS, provides the ability for the ADMS to obtain information from one or more external Supervisory Control and Data Acquisition (SCADA) systems.

- Analytics - The Analytics module of the ADMS/NMS provides the ability to analyze historical data captured in the ADMS and produce reports and other analysis of the data in a summarized fashion. This allows managers, engineers, and other people to identify trends and potentially take action to improve aspects of the system in the future.
- Operational Technology Message Bus – The Operational Technology Message Bus is a module of the ADMS/NMS that connects the ADMS to multiple other internal and external systems, typically other operational technology (OT) systems.

Additional data sources were part of the demonstration. The new data sources included:

- WFI data – Wireless Fault Indicator data is information that comes from fault indicators in the field that are connected via a wireless communications network.
- AMI LV Alarms – AMI Low Voltage alarms are generated from AMI meters when they detect that the voltage at the meter drops below a predetermined threshold.
- Weather data – Incorporate direct integration of relevant weather data into the NMS for easier operator training and improved operator usability.
- Advanced Protective Relay data – Advanced Protective Relay data is information from microprocessor-based protection relays with embedded sensors that provide advanced data streams such as fault currents and other protection information.
- Phasor Measurement Unit (PMU) data – Phasor Measurement Units collect measurements of voltage and current at very rapid rates that are GPS time synchronized.

The diagram in **Fig. 1** represents the high-level view of the software that was deployed as part of this EPIC project. The system was deployed on two additional servers.

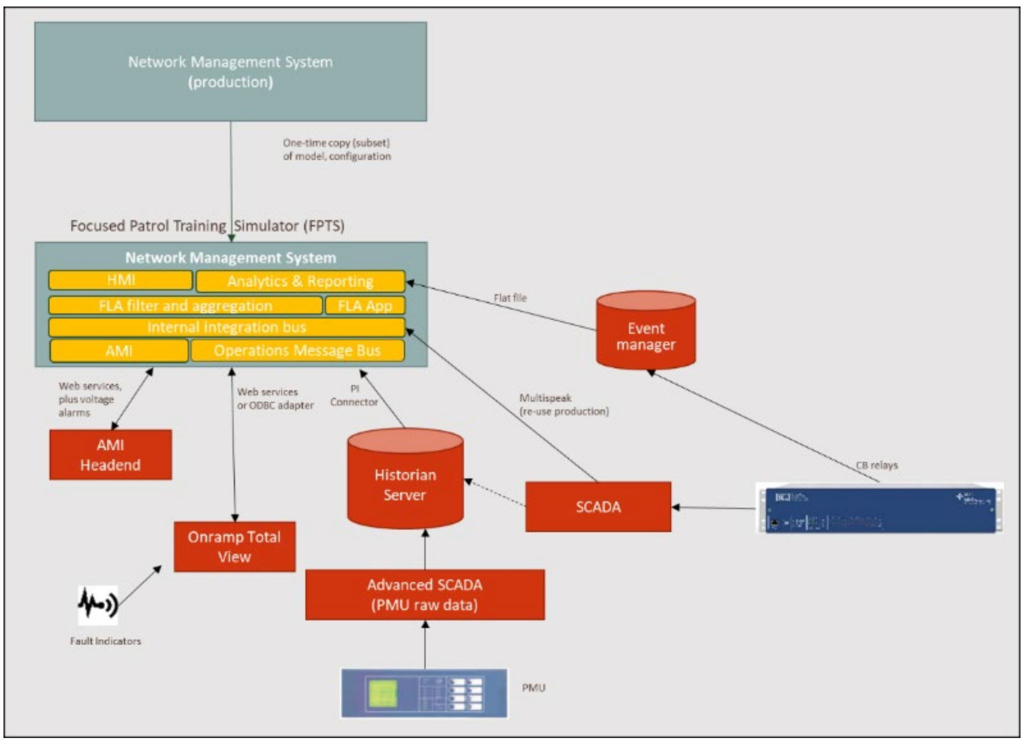


Fig. 1. Software Architecture

SECTION 3. DEMONSTRATION DEVELOPMENT

Approach and Description of Demonstrations

The final approach utilized in this project was to analyze each of the data sources identified and determine the use cases impacted and demonstrate how they could be used to improve operator response. This section of the report describes how each data source was investigated, the impacted use cases and the findings associated with that data source. The following data sources were investigated and demonstrated:

1. Wireless Fault Indicators (WFI)
2. Advanced Metering Infrastructure (AMI) Low Voltage (LV) alarms
3. Weather Data
4. Advanced Protective Relays
5. Phasor Measurement Units (PMU)s

The following sections cover the details of each of the investigations done for each data source itemized above.

Wireless Fault Indicators

Wireless Fault Indicators – Introduction

Fault indicators are a common device placed on distribution overhead conductors and used in the field to assist in trouble shooting by indicating that fault current has been detected and the actual fault should be downstream of any fault indicator that reported a fault current. Fault Indicators are typically located on the feeders and present status of the fault current detection in a way that can be seen by a patroller with a flag or light. Wireless Fault Indicators are battery-operated and have a radio allowing them to reach out through a wireless network and provide the status back to the NMS. The communications network is designed to provide data within a few seconds allowing the data to be used in the FLA algorithm similarly to how it is used in the field. Several typical wireless fault indicators as deployed in the field are shown in **Fig. 2**.

Fig. 2. Wireless Fault Indicator (WFI) Devices installed in the field

Since the Fault Location Analysis algorithm often produces multiple possible fault locations, which requires field crews to patrol multiple branches to confirm a fault location, it is desirable to add sensors to assist in further narrowing down the possible fault locations. Fault indicators are a sensor device that detects the presence of a fault current at the location they are installed on the distribution system. A simple state of fault current was detected or not detected is all that is needed to improve the fault location algorithm.

Placing WFIs at strategic locations such as at the bifurcation of branch segments can help identify which branch should be patrolled. This is because the fault indicator will have a positive state at the head of the branch where the fault occurred and a negative state at the head of all other branches that didn't see the fault current. When one branch segment is directly downstream from another segment, the fault indicator status also indicates the upper and lower bounds of a fault location when the upstream fault indicator reported a fault current detected and the downstream fault indicator indicates no fault current detected. See **Fig. 3.** for an example of placements of WFI devices at branch locations of a feeder.

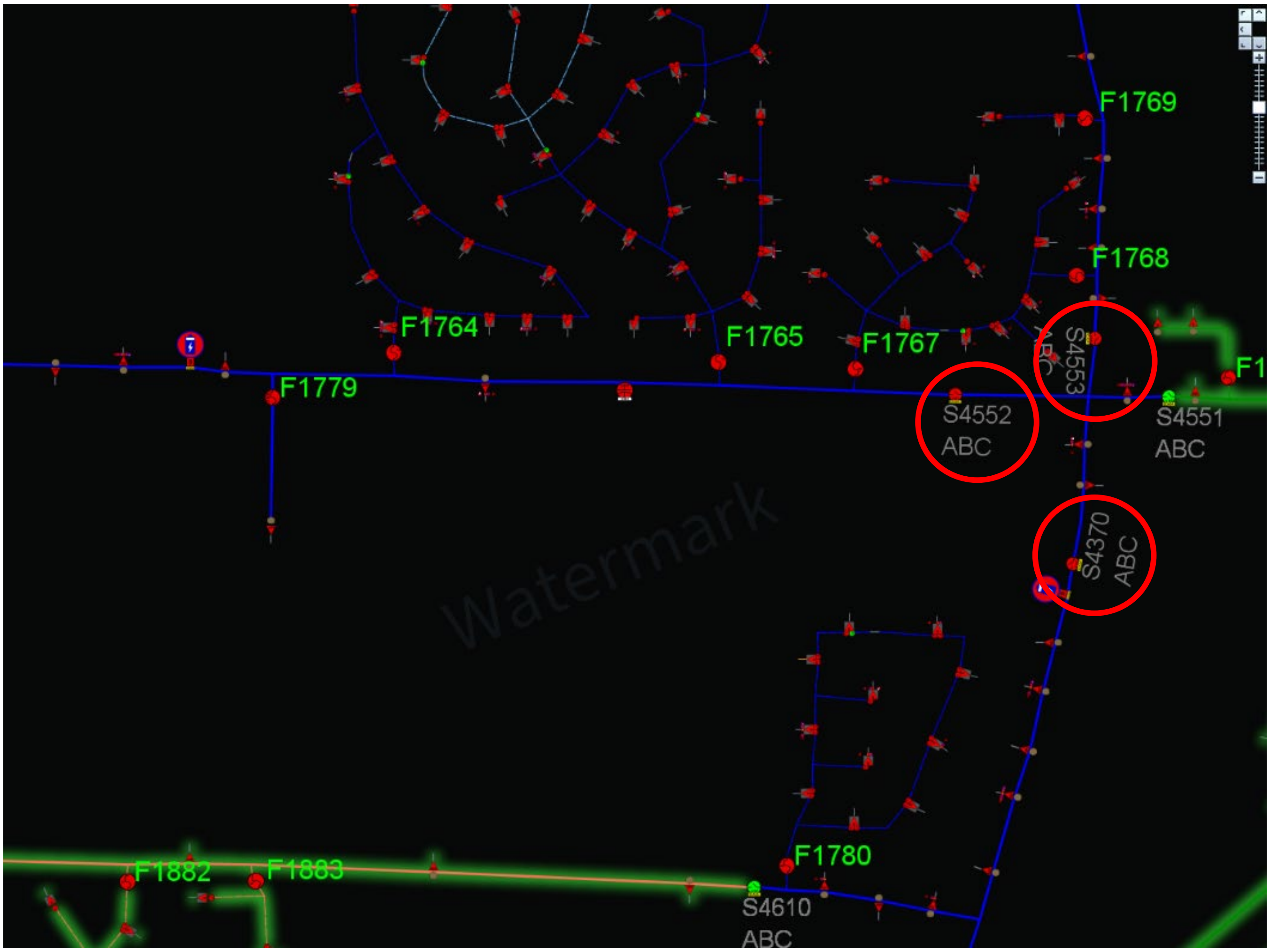


Fig. 3. Strategy for Locating Wireless Fault Indicators (WFI)

Wireless Fault Indicators - Data Source Analysis

The following describes the use of an ADMS Fault Location Analysis (FLA) function, first without any Wireless Fault Indicators (WFI) and then with the WFI data source added to the FLA function.

Fault Location Analysis without WFI

Fault Location Analysis (FLA) is a standard function in modern ADMS platforms. It uses short circuit analysis and three-phase telemetered fault currents measured at a circuit breaker to calculate the distance to a fault. The calculated distance to the fault is a function of the measured fault currents, and the impedance to the fault and the location of the fault as well as taking into consideration the loading on a circuit at the time of the fault. This approach has been researched extensively and implemented successfully [9] [10] [11]. Since distribution circuits typically branch out in many different directions, with various conductor sizes and configurations, the fault location algorithm potentially will identify more than one possible fault location. The predicted locations can also potentially be different distances from the breaker if the impedances differ on each path. An example where FLA identifies multiple fault locations on different branches at different distances is shown in **Fig. 4** and **Fig. 5.**

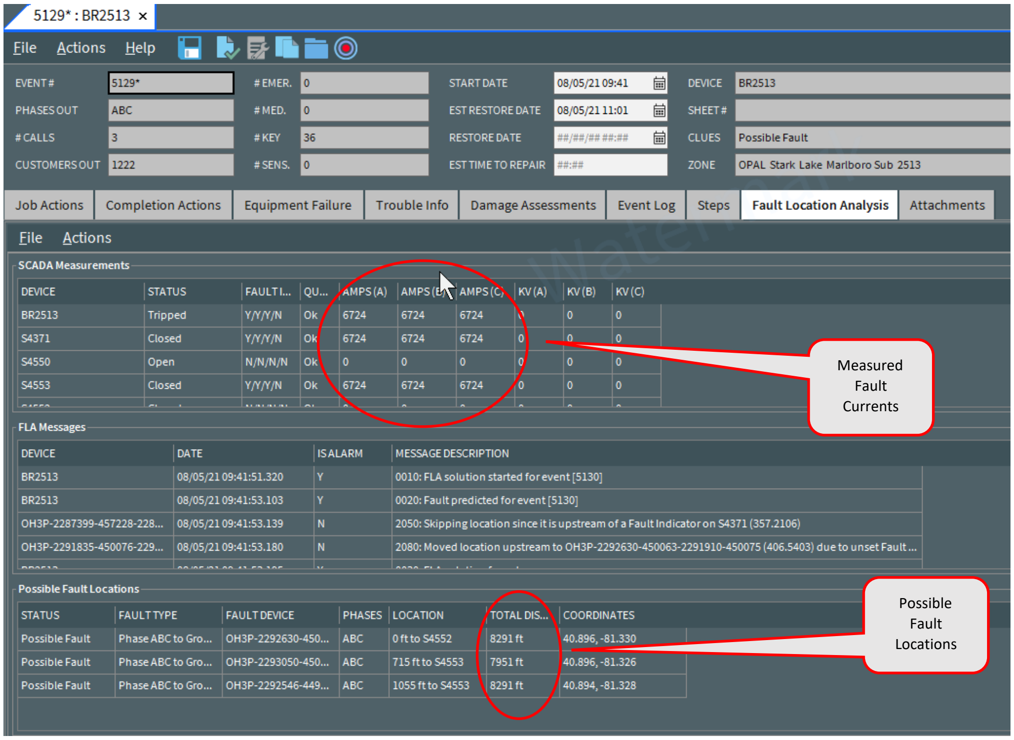


Fig. 4. Fault Location Analysis Calculation Results

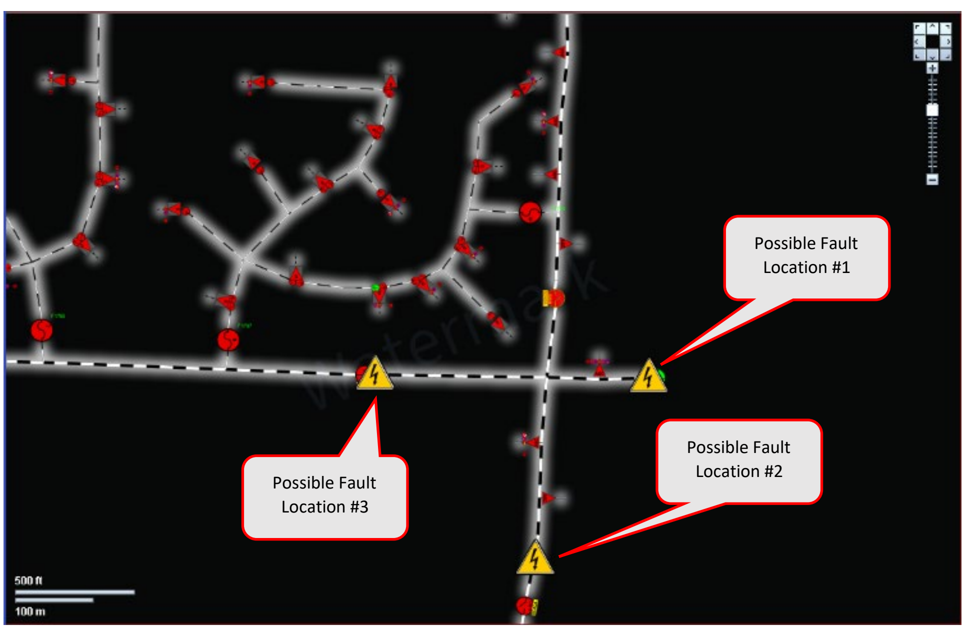


Fig. 5. Graphical Results of FLA showing three possible fault locations

In situations where the FLA algorithm identifies multiple fault locations, dispatching a crew to patrol the different branches is required to determine the correct location. Within the NMS, the operator can confirm, mark “incorrect” or “correct” the fault location based upon information provided by the crew in the field. An example of the dialog used to report this information is shown **Fig. 6**

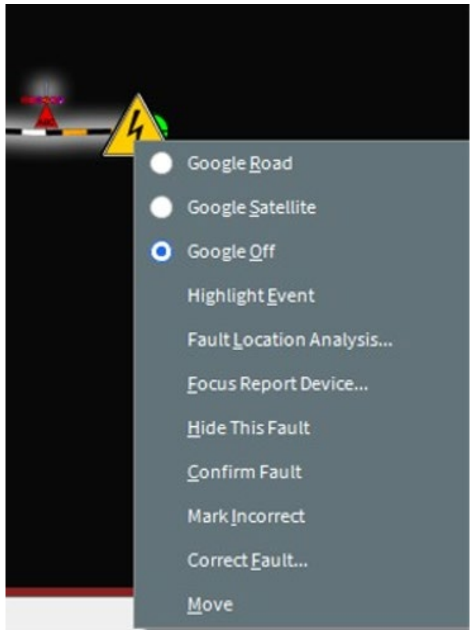


Fig. 6. Fault Location Options

After the fault the has been confirmed at the correct location, the symbology changes to indicate the confirmed fault location, as shown in **Fig. 7**. The FLA function is also able to indicate that the other possible fault locations are incorrect as shown in **Fig. 8**.

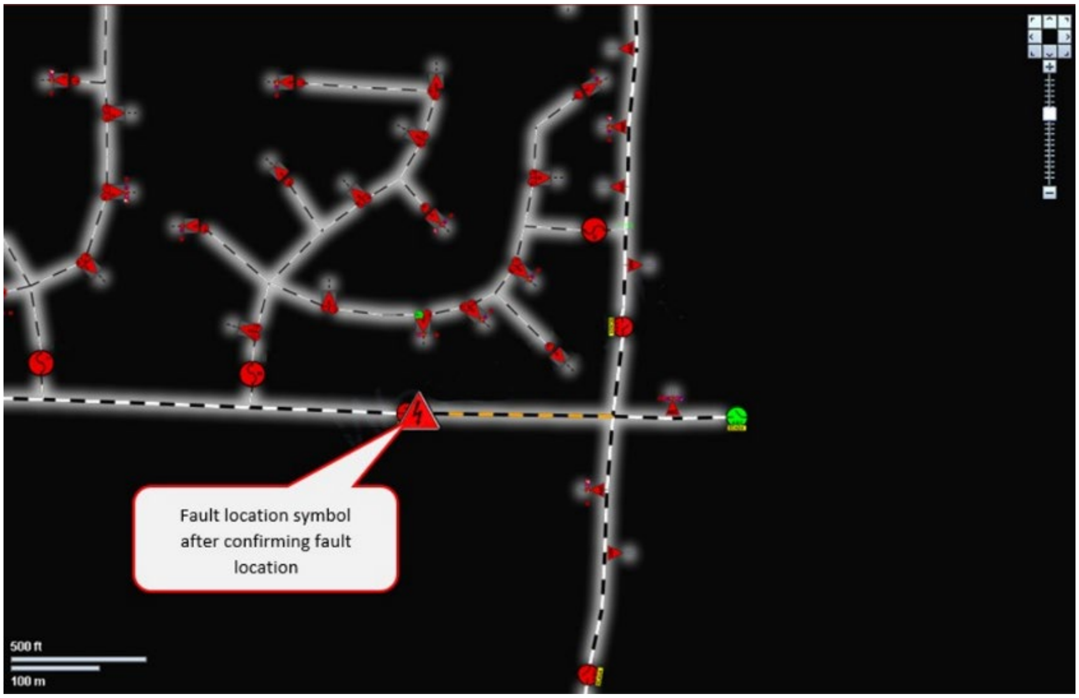
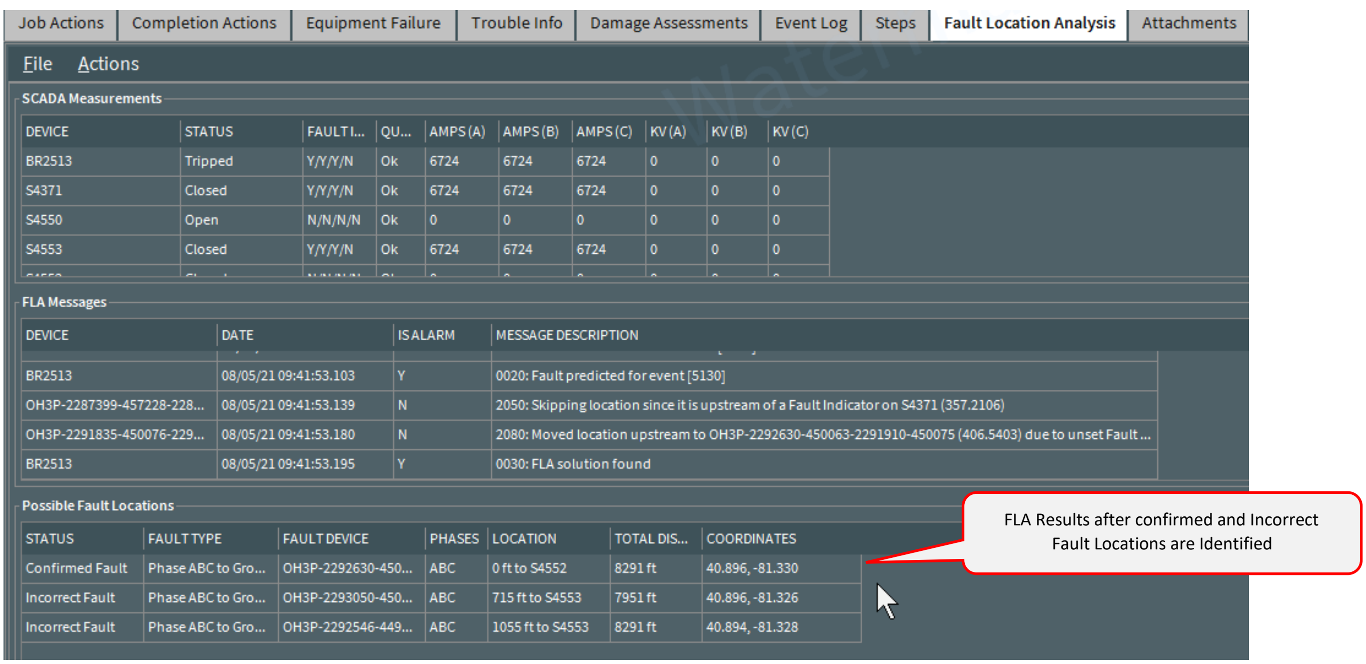


Fig. 7.   FLA Results After Confirming Actual Fault Location



DEVICE	STATUS	FAULT I...	QU...	AMPS (A)	AMPS (B)	AMPS (C)	KV (A)	KV (B)	KV (C)
BR2513	Tripped	Y/Y/Y/N	Ok	6724	6724	6724	0	0	0
S4371	Closed	Y/Y/Y/N	Ok	6724	6724	6724	0	0	0
S4550	Open	N/N/N/N	Ok	0	0	0	0	0	0
S4553	Closed	Y/Y/Y/N	Ok	6724	6724	6724	0	0	0

DEVICE	DATE	IS ALARM	MESSAGE DESCRIPTION
BR2513	08/05/21 09:41:53.103	Y	0020: Fault predicted for event [5130]
OH3P-2287399-457228-228...	08/05/21 09:41:53.139	N	2050: Skipping location since it is upstream of a Fault Indicator on S4371 (357.2106)
OH3P-2291835-450076-229...	08/05/21 09:41:53.180	N	2080: Moved location upstream to OH3P-2292630-450063-2291910-450075 (406.5403) due to unset Fault ...
BR2513	08/05/21 09:41:53.195	Y	0030: FLA solution found

STATUS	FAULT TYPE	FAULT DEVICE	PHASES	LOCATION	TOTAL DIS...	COORDINATES
Confirmed Fault	Phase ABC to Gro...	OH3P-2292630-450...	ABC	0 ft to S4552	8291 ft	40.896, -81.330
Incorrect Fault	Phase ABC to Gro...	OH3P-2293050-450...	ABC	715 ft to S4553	7951 ft	40.896, -81.326
Incorrect Fault	Phase ABC to Gro...	OH3P-2292546-449...	ABC	1055 ft to S4553	8291 ft	40.894, -81.328

Fig. 8.   Fault Location Analysis Tabular Results

FLA Using Wireless Fault Indicators (WFI)

When WFI devices are placed strategically and included in near real-time data in the FLA algorithm, the ADMS can identify the potential branches where the fault occurred and then eliminate the branches where the WFI data indicates that no fault occurred. An example of the results of FLA disregarding potential branches based upon fault indicator data is shown in **Fig. 9.**

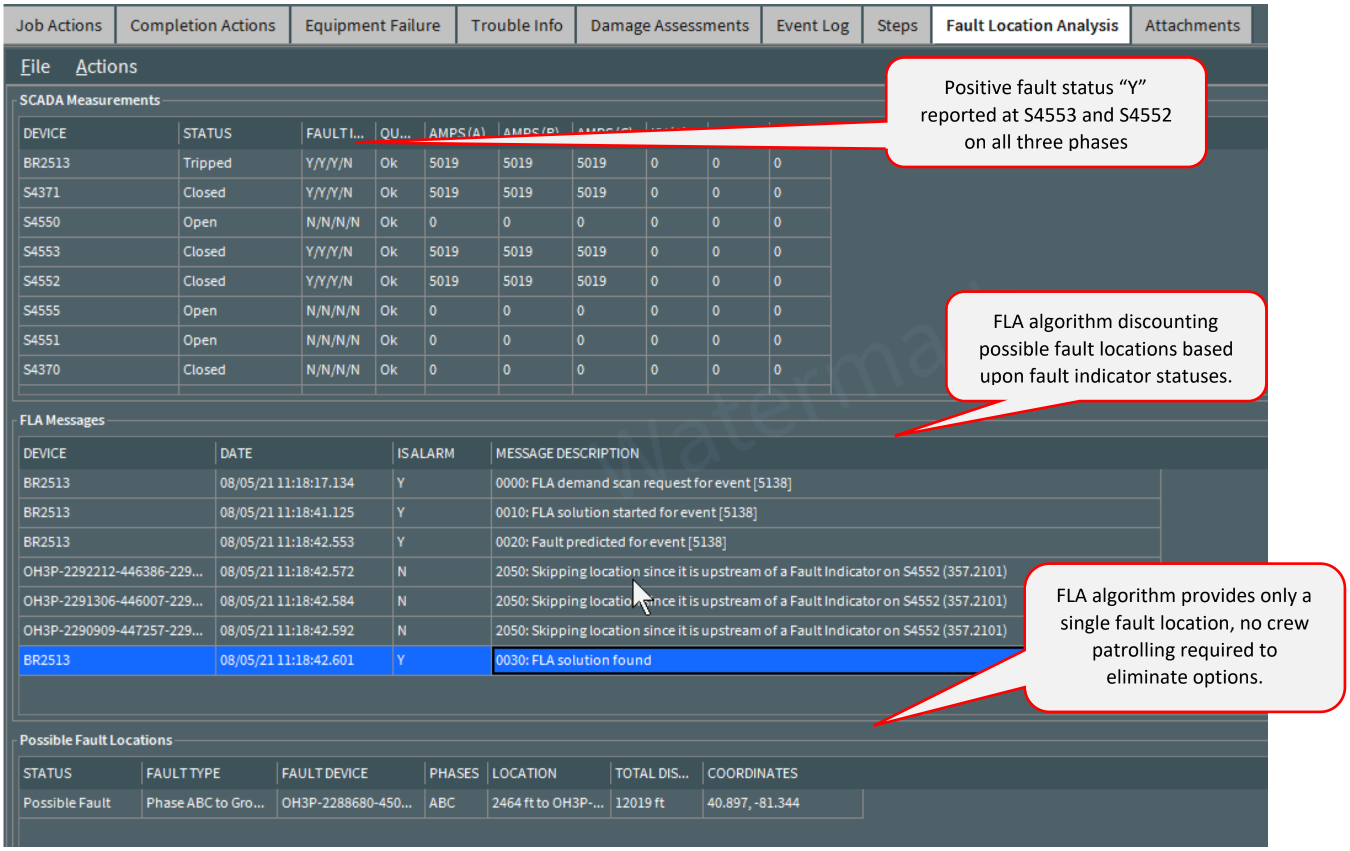


Fig. 9. FLA Tabular results of Fault Location showing additional WFI analysis

The single fault location is shown graphically in the map viewer in **Fig. 10.** Although the FLA has not confirmed the location and it still requires the crew to patrol the branch with the identified fault, it is still valuable because the need to patrol multiple branches is eliminated and the crew can focus on confirming the location of actual fault on a single branch. A reduction in patrol time and driving incident exposure will be realized.

Fig. 10. FLA graphical results with WFI analysis

Wireless Fault Indicators – Data Source Findings

The standard FLA functionality in NMS can be setup to do a traditional demand scan via SCADA to ensure all SCADA data is current before calculating fault locations. Since WFI communications are event driven and not performed with traditional SCADA, a demand scan is not possible. There are two possible alternatives that could be implemented: 1) the FLA algorithm could be modified to support waiting for WFI device response instead of or in addition to a demand scan, or alternatively, 2) the FLA could perform the fault location analysis and initially provide multiple fault locations and then using the WFI events correct and eliminate any possible faults that are not consistent with the WFI event data.

Even without the modified FLA algorithm, NMS can be configured to prominently show the locations of all WFI, providing the operator with visual indicators of WFIs that should be examined for fault reports before dispatching crews to patrol multiple branches. This would be considered a manual equivalent to the automatic mode described above. The software could be configured to be modal and support both the manual mode and the automated feature.

AMI Low Voltage Meter Alarms

AMI Low Voltage Meter Alarms - Introduction

Automated Meter Infrastructure (AMI) systems are used to automatically collect meter readings from the point of connection between the distribution system and the point of service for a customer. Initially developed for the purposes of automatically reading power demand and consumption for the purposes of billing, AMI systems are also able to provide additional data from the meters that can be used in electrical operations. The use of AMI data for multiple purposes is often called smart metering.

AMI meters can report the loss of power, sometimes called a “last gasp” message because it is the last message that can be sent due to the loss of power. They also can report the energization of the meter after power is restored. These two messages from an AMI system are often sent to the Outage Management System (OMS) functions of an ADMS.

Additional messages from AMI meters such as the detection of low voltage and high voltage events are also available from an AMI system. Low Voltage Alarms are potentially valuable during fault scenarios because the fault conditions can cause sustained or momentary low voltage situations during the time the fault is present.

AMI Low Voltage Meter Alarms - Data Source Analysis

Current as-is Use Cases for patrol work, other sources of information not currently being sent to the NMS system but available through other systems/means were investigated. Low voltage meter messages fall into this category. The investigation carried out was to identify any benefits to focused patrol teams, narrowing down potential fault areas allowing the team to isolate the fault area in the quickest possible time. This kind of data would be specific to “downed conductor/open jumper outages” and, more importantly, “energized downed conductor”.

Table 3 shows the current meter Power Off message filters currently used in the NMS software. This will be used as a reference and may be useful to apply to any additional meter messages.

Table 3 Current LV Meter Power Off Message Filters

Category	Rule Name	Rule processing order	Power off/on or both	Description
Unplanned	Correct message	1	Both	Ensure it's a correction message: power off/on
	Old Alarms	2	Both	If the new ‘Timestamp’ field on the alarm is >15min old, discard the alarm. Power off and on.
	Dups – Same Meter	3	Both	Filters out duplicate alarms based on distinct (ESN + Power Off/On) if within 10min.
	Dups - Same Outage ID	4	Both	Filters out duplicate alarms based on distinct (Outage ID + ESN) as unique key on which to

Category	Rule Name	Rule processing order	Power off/on or both	Description
				filter. The Outage Filter would discard any duplicates received within 60min.
	Service Orders	5	Both	Look for existing service order for that ESN, +/- 2 days (uses date only, not time), then discard power on/off.
	Power Off - Active Outage Filter	6	Power Off	Compares the Power Off message to the OUA Active Outages view. If the Power Off message timestamp is either (1) at or before the outage start time or (2) is >=10min after the outage start time, the message will be discarded
Planned	Power Off - Planned Outage Filter	7	Power Off	Filters Power Off alarms that have a related planned outage record in Planned Outages view.
	Power On - Restored Outage Filter	8A	Power On	Filters Power On alarms that have a related restored outage record in OUA Restored Outage view.
	Power Off - Restored Outage Filter	8B	Power Off	Filters Power Off alarms that have a related existing restored outage record in OUA Restored Outage view.
	Power Off - TLM process	9	Power Off	Gets Transformer Load Management data for power off - to get the transformer. If no matching transformer found, discard power off
	Single power off	12	Power Off	Wait for a 2nd power off on a transformer before sending it to NMS.
	Single Meter on Transformer	13	Power Off	Outage Filter will check if that meter is the only meter on the transformer/primary meter. If it is, it will send through.
	Duplicate Filter - Single Meter	14	Power Off	Will not allow duplicate meter through within 2 mins

Relevant Use Cases

The following use cases were identified for investigation into the value of AMI Low Voltage messages:

- Use Case 1: Wire Down
- Use Case 3: Foreign Object in line
- Use Case 4: Tree/Vegetation Contact

- Use Case 6: Underground distribution – need to investigate (might depend on transformer type delta vs wye primary)

Current State

LV meter messages are currently sent from smart meters within the network. The system has practically a full rollout of smart meters throughout the network. At present, loss-of-power messages are sent from the Meter Management system to the NMS system and are used to help determine the scope of a fault/de-energized section of the network. Low Volt messages are sent from the meters but are currently not sent on to the NMS system. This concept was recently proposed and validated on several distribution systems [3]. This investigation was to determine if receipt of such messages in the NMS system will benefit the patrol crew dispatch.

Network Area

An area of the network was identified from a list of potential substations and circuits provided by the customer. This area has been selected as it has good power flow information and is an overhead section of the network abundant with distribution transformers with associated customers, several protection devices, and several lateral lines being fed from the main feeder with different phase configurations. The environment is primarily rural, typical of the eastern sector of the county. The area selected is:

- Substation R, Feeder: 6, Feeder Head Breaker: 12kv-111
- Downstream Normally Open Points:
    - NOP point: 6-T2-9 (Gang-operated OH LB switch)
    - NOP Point: 6-T3-10 (SCADA Fault Interrupter)

Simulations

Several scenarios in line with the Use Cases were identified and demonstrated to determine the value of AMI low voltage messages.

Fig. 11 shows a simulation where the star symbol represents a potential wire down location. At the time of the fault, the DSO would be unaware of the fault location.

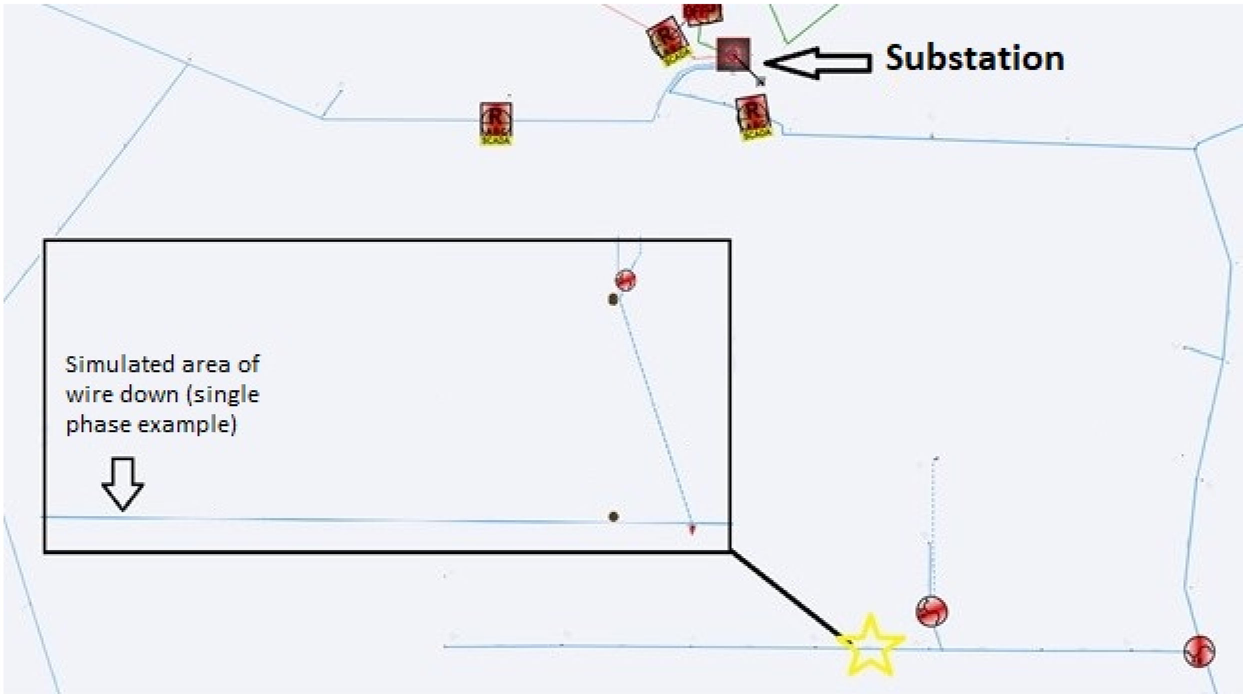


Fig. 11. Wire Down Simulation in NMS

Use Case #1, Scenario 1: Trip and Successful Reclose

In this scenario, it is assumed the recloser upstream of the fault trips and after one or more attempts successfully recloses. The assumption is that the protection device at the start of the lateral has operated on one of the phases clearing the fault and allowing the recloser to successfully reclose. Alternately, a foreign object such as a tree branch could have cleared itself from the line. The lateral line is 2-phase (Phases A and B). For these purposes, we will assume Phase A fuse has operated.

As documented in ***Use Case #1 of Appendix A – Use Cases***, several tasks will be carried out by NMS regarding the managing of the successful reclose (capture of a momentary outage). As only one phase fuse has blown, there will be no *complete* "Loss of Power" messages received from any downstream meters. Until a customer calls in, the operating staff will not be aware of the outage.

Table 4 shows how to perform the steps to simulate this Use Case scenario.

Table 4 Test Steps for Use Case Use Case #1, Scenario 1: Trip and Successful Reclose

Basic flow			
Step	Actor	Action	Expected result
1	NMS simulator	Action	Simulated Trip open on Recloser 1
		Expected Result	NMS shows nothing. Recloser timer is started
At this stage Phase A fuse operates. This device is not SCADA capable so the operator will be unaware			
2	NMS simulator	Action	SCADA recloser 1 automatically recloses

Basic flow			
		Expected result	The recloser closes and remains closed. The timer in NMS expires. A momentary outage is opened to manage the momentary outage caused by the recloser open in the previous step.
3	NMS Simulator	Action	After an amount of time calls are received from customers on lateral #2 Customer Account #: Call 1 – Customer 1 Call 2 – Customer 2 Call 3 – Customer 3 ***See note***
		Expected result	The first call would result in a PSO event being raised. This would be associated with transformer Tx 1 – the Tx the customer is associated within the system. Second call is associated with transformer Tx 2. This would extend the scope of the PSO to a PDO. Both calls would be associated to this PDO. The predicted scope would be up to Fuse 1. The 3rd call is within the scope of the PDO and would be automatically associated with it.
4	Tester	Action	Clear all events and calls
		Expected results	All events and calls are cleared.
Alternative flow This flow assumes we are receiving “Low Voltage” messages from meters within the scope of this network area			
2a	NMS Simulator	Action	Within minutes of the recloser closing and the timer expiring, meter “low voltage” messages are received from meters Meter 1, Meter 2, Meter 3.
		Expected results	As with calls, the first meter message would create a PSO associated with Tx 1. The second message would extend the scope of the PSO to a PDO. Both meter messages would be associated to this PDO. The predicted scope would be up to Fuse 1. The 3rd meter message is within the scope of the PDO and would be automatically associated with it.

Note: There are only 4 customers fed from this lateral line. This reduces the likelihood of calls arriving close to the time of the initial recloser action.

Findings – Use Case #1, Scenario 1

In this scenario, a single fuse has operated (blown), but the power is not actually out due to the other phase being live. This is due to the 2-phase supply and the wiring at the sites on the line and use of Delta transformer configurations. No “Loss of Power” messages would be received from meters as they would not completely lose power. The earliest time the operators are alerted to the fuse blown event is when customers or bystanders call in to report an issue with their supply or a dangerous situation. Due to the low number of customers on this lateral, the time to realize the issue and report it is a factor in the time to realize there is a fault situation, possibly with an energized conductor down. There’s no doubt that a service interruption has occurred, but the exact nature of the interruption/system failure is not understood until later, perhaps much later in areas of sparse customer density.

The alternative test shows if “Low Voltage” messages were received from the meters along this line, the operators would be alerted to the situation potentially within minutes of the fault. There would be an improvement in the fault realization time and therefore a quicker response to the fault than just relying on on/off AMI or caller information. There are other situations where this is valuable such as when no power-off messages are received because no meter sees an absolute zero voltage. This would reduce the outage duration and potentially reduce the duration of any dangerous situation. The configuration of SDG&E’s AMI system is that the meters will continue to communicate even during periods when the voltage is as low as 50% of nominal.

Use Case #1, Scenario 2 - Trip and Lockout

Using the same area of network as before, this scenario sees the SCADA Recloser 1 trip and after one or more attempts to reclose remains in an Open state. In this scenario, all areas of network downstream to the open points would be de-energized. Meter “Loss of Power” messages would be received and sent to the NMS system using the meter notification rules. With this information and SCADA information related to the recloser, the operator would know the recloser has tripped and the circuit is de-energized. There would be no Low Voltage messages from meters as they are all in a de-energized state, and no longer communicating. The as-is process would then be used to find the outage would be required.

Operators would be looking out for any additional information in the scope with regards to dangerous situations. This may give good indications/clues to the location of the fault area.

Findings Use Case #1, Scenario 2

In this scenario, no “Low Voltage” situation on meters would be detected, therefore the addition of these types of messages would not reduce the time or change the process of discovering the fault area.

Dangerous-situation or damage calls are currently received but may not automatically be associated with an event. It is currently up to the operators to recognize this event, potentially using the “hazard” column in the work agenda. Currently, SDG&E has audible alarms disabled on the NMS system. A potential improvement would be to enable audible alerts for damage calls, etc. to improve operator awareness

Use Case #1, Scenario 3 Non-SCADA device operates

Refer to use case #1. Same results but without the SCADA momentary operation

Use Case #1, Scenario 4: Breaker does not trip, fuse does not open

Typical examples of this type of fault would be high impedance faults. These faults occur when a conductor touches the ground surface or a tree. The fault current generated is minimal and may not cause protection equipment to operate.

- Location for Test: Substation W, Feeder 1, Break between Pole 1 and Pole 2 Phase A (line to Ground)

There would be no FLA help in this scenario due to no SCADA trip and no WFIs are present. Meters downstream of the break may detect low voltage (fed from Phases A and B). A Predicted Device Outage (PDO) is automatically created based on Meter LV calls. As shown in **Fig. 12**, the scope of the outage prediction is extensive with the magenta highlighted section downstream of the PDO.

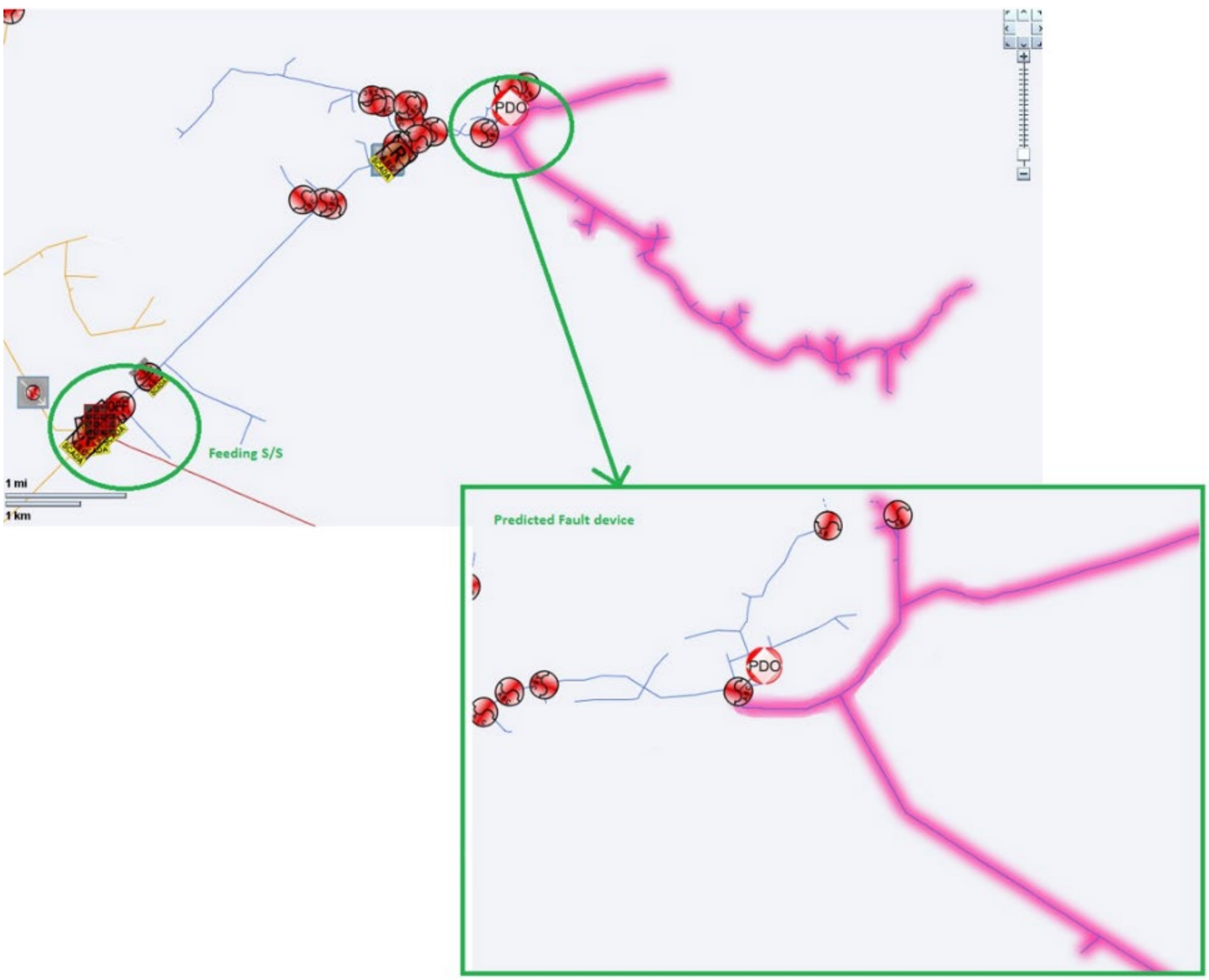


Fig. 12. Use Case #1, Scenario 4: Breaker does not trip, fuse does not open

Using the Hide/Display tool, the operators can turn on the AMI LV message indications. This will show the LV messages and their location and narrow down the search. Operators would see the first meter LV messages downstream of the wire down location as shown in **Fig. 13**.

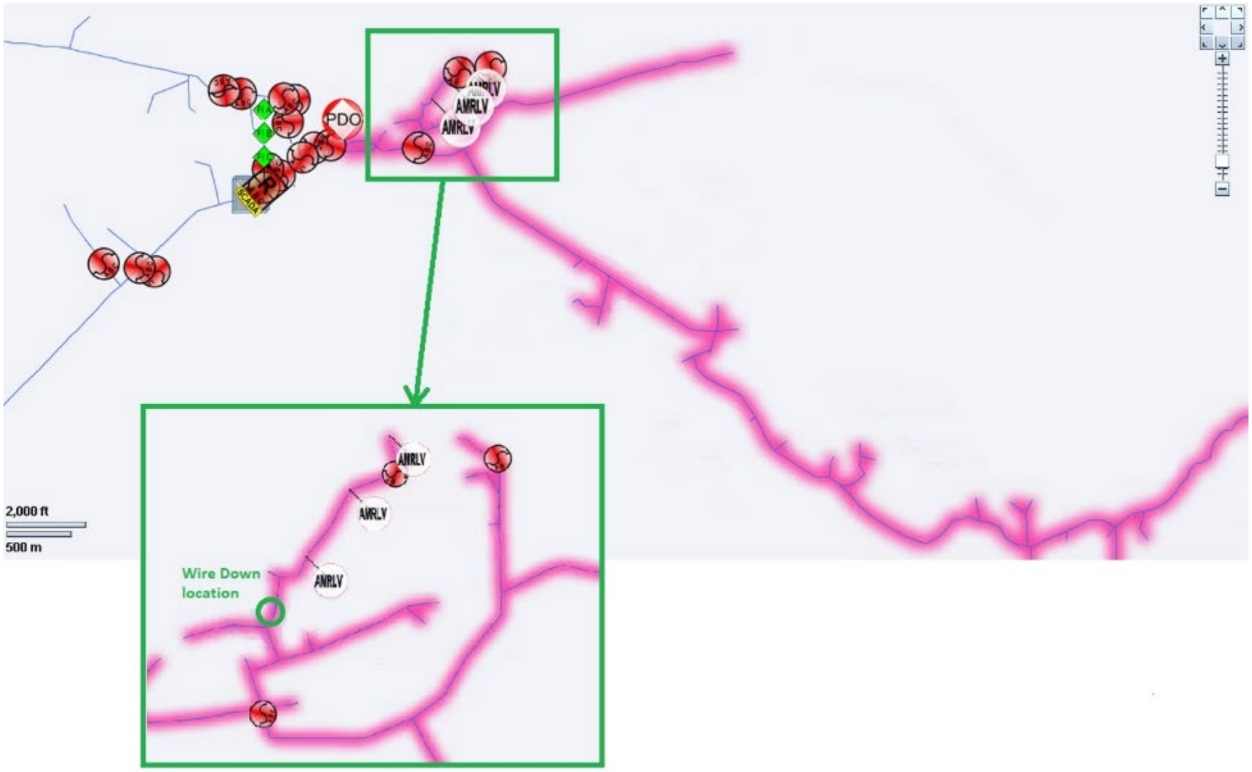


Fig. 13. AMI LV messages for Use Case #1, Scenario 4: Breaker does not trip, fuse does not open

Patrol crews can then be sent to this location and work upstream to find the fault.

Note – PDO created with meters – otherwise they would have to wait for customer calls to even realize there is a fault. Only 4 customers reside on this lateral. So, a lengthy time lapse may occur before the fault may be realized depending on time of day, residency status of customers, etc.

Fig. 14 and **Fig. 15** shows a similar simulation but where the fault is on Phase B, between two poles. As before the Meter messages are received and a Predicted Device Outage (PDO) is automatically created with a downstream highlighted area in magenta.

Fig. 14. Phase B Fault for Use Case #1, Scenario 4: Breaker does not trip, fuse does not open

Again, the scope is significant with lateral lines going in different directions causing potential difficulties in finding the fault location.

Switching on the AMI LV messages significantly reduces the search area as shown in **Fig. 15**

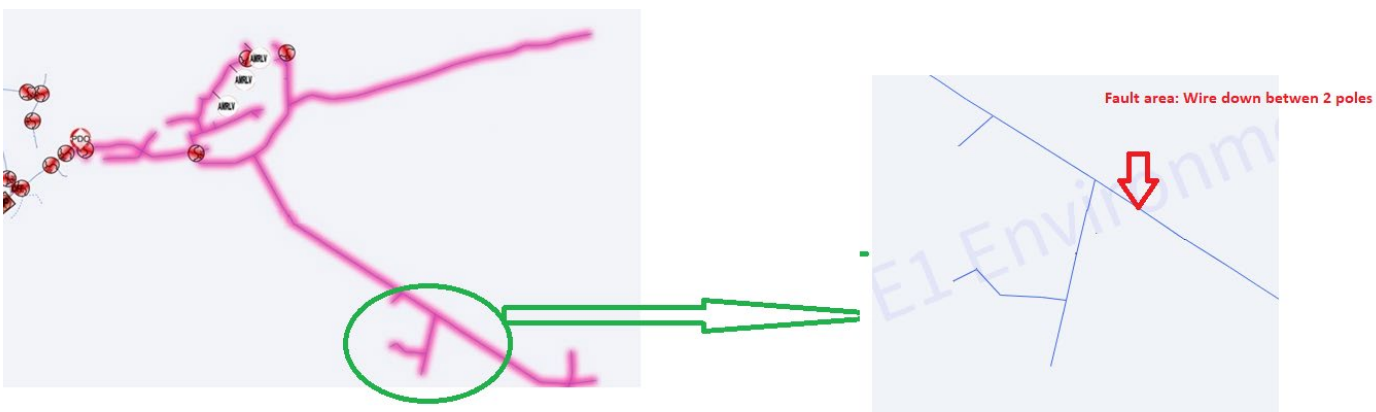


Fig. 15. AMI LV messages for Use Case #1, Scenario 4: Breaker does not trip, fuse does not open

In this scenario, we have simulated some meter messages but not messages from every meter within the fault scope. This is to simulate the fact that not all meter messages will arrive, due to communication issues.

In this case, the first meter downstream of the fault fails to communicate. The presence of the other meter LV reports would enable the Operator to go to the first AMI LV message and work upstream, either pinging/requesting voltage from meters upstream initially and dispatching patrols.

In the current situation, the system operator would have to wait for customer calls. Many more customers may call in, but it is likely that meter messages would arrive first.

Findings – Use Case #1, Scenario 4

Low Voltage messages downstream of the fault would be received and will significantly aid in identifying the fault area. It would save time in identifying if there actually is a fault. Even when some meters fail to communicate, there are likely to be enough messages to determine the best location to start the search.

Note: Use Case #3, Foreign Object in Line and Use Case #4 Tree/Vegetation Contact have similar findings to Use Case #1.

Use Case #6, Underground Distribution

The underground network uses a combination of delta and wye transformers. In the case of the delta transformer configuration, the Low Voltage message may give an indication of an outage in a similar way to the Overhead network as described in Use Case #1 in Appendix A – Use Cases. The following areas have been identified as potential test areas:

- Underground distribution section (dashed conductors) shown downstream of the fuse.

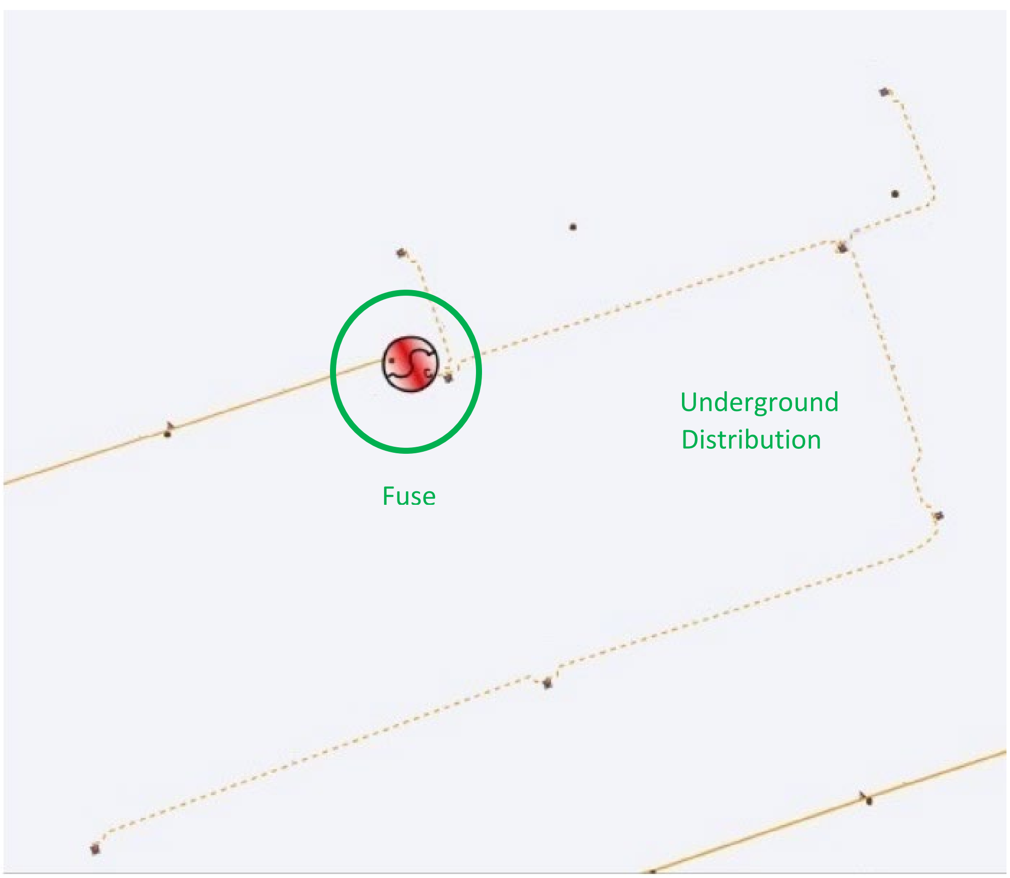


Fig. 16. Use case #6, Underground Distribution

Expected results would be that Low Voltage messages would not help in the case of a wire down as this area is single phase. One would expect Loss of Power messages would be received.

Fig. 17 shows the area around a Transformer fed from a Substation.

Fig. 17. Location of Transformer in Use Case #6, Underground Distribution

Findings – Use Case #6

Enabling and testing scenarios on the underground network is required to further identify if the use of Low Voltage messages will aid in the identification of a fault that may be reliant on the receipt of customer calls.

AMI Low Voltage Meter Alarms - Data Source Findings

Low Voltage (LV) messages from meters can enhance the operator's current ability to diagnose potential fault areas by providing this additional information.

In conditions where a non-SCADA device has operated on a single phase where there are multiple phases on the line, operators may only be made aware of the outage via customer calls. The timing of these calls will vary depending on time of day and number of customers affected and location. For example, on a rural network in the middle of the night, customers may not call for some time.

Where the configuration of the transformers is Delta, low voltage would be detected from meters. If these messages were passed to the NMS, this would result in automatic outage events being raised in the area of the fault. This would alert operators within minutes (depending on configuration rules) to the fault. This has the potential for saving time and minimizing dangerous situations where an energized line is down, etc.

Dangerous situation or damage calls are currently received but may automatically be associated with an event. It is presently up to the operators to spot that this has occurred potentially using the "hazard" column in the work agenda. Currently SDG&E has audible notifications disabled on the NMS system. A potential improvement would be to enable audible alerts for damage calls, etc. to enhance operator awareness.

Fig. 18 shows how the LV Meter messages can help with location finding when used in conjunction with FLA.

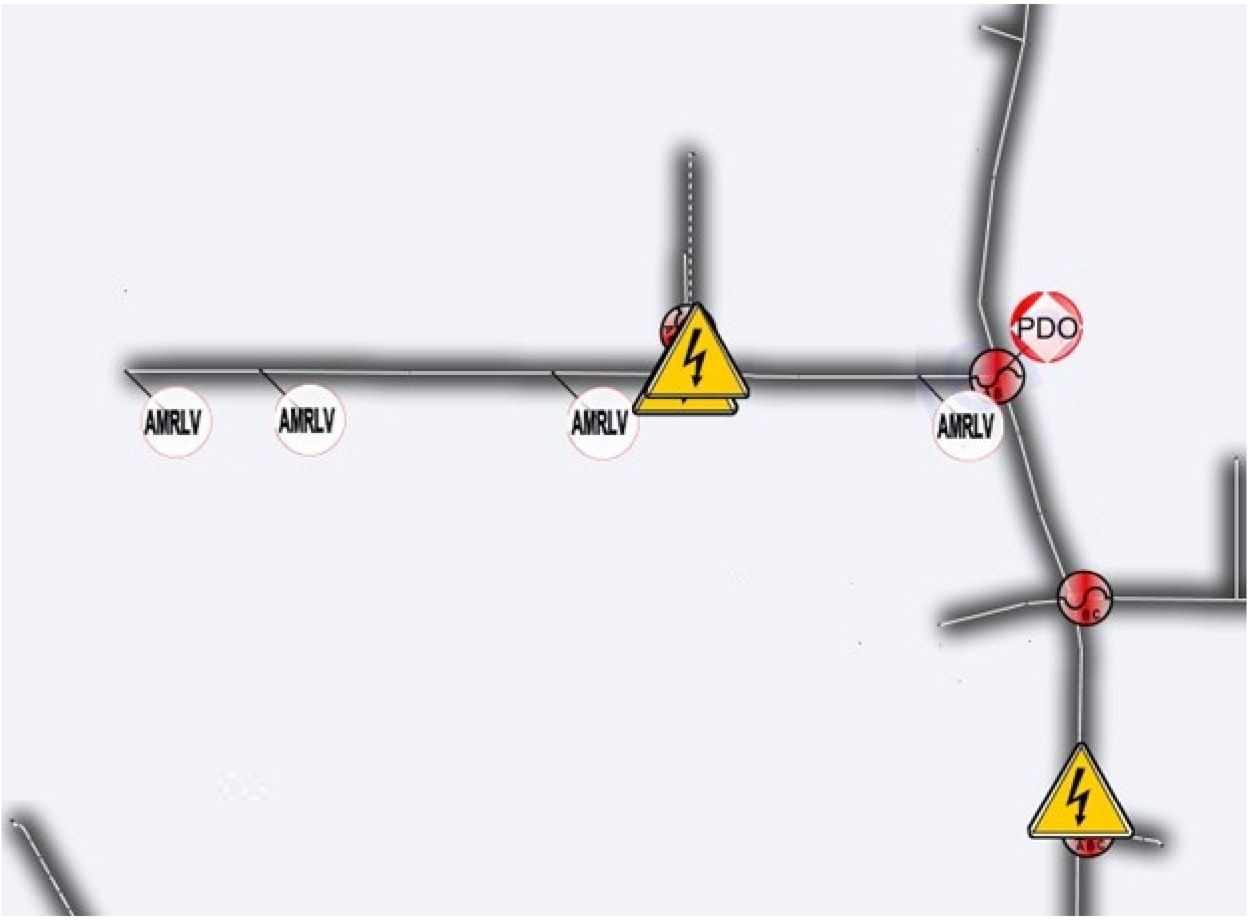


Fig. 18. FLA with LV Meter messages, yellow triangles show the potential fault locations

The yellow triangle symbols are the FLA potential locations. As you can see, there are 3 possibilities. When used in conjunction with AMI LV messages shown in the figure with white circles, you can see the likely location will be the lateral, not the main line in this case.

Configuration of Low Voltage messages and rules associated with them should be defined and configured to allow further testing. From the analysis, the following regulations/requirements have been identified. The “In scope” requirements should be included where possible within the scope of the Focused Patrol project. “Future” requirements identify features that have the potential to be included in the NMS product, although where possible, will be demonstrated via a temporary configuration.

Table 5 Proposed Configuration of Low Voltage Messages

Rule ref	Details	When?	Comments
1	Enable Low Voltage messages to be passed from the AMI system to NMS	In scope	
2	New meter message type to be created for Low Voltage messages	In scope	
3	Define rules for the passing of LV messages from AMI. (Use Power Off filters as a guide)	In scope/future	Some rules can be identified and simulated within the project
3a	Low Voltage messages only when no "Loss of Power" exists on any phase of same feeder/lateral	In scope	If this can be done via configuration for demo purposed
3b	Low Voltage only when Delta configuration is used	In scope	If this can be done via configuration for demo purposed. This is only when more than one phase exists on the line
4	No low voltage messages on wye transformer configuration	Future	But can avoid this configuration during demo
5	Method to group meters and request Voltage measurements from each in the group	Future	Mentioned by SDG&E. Would benefit investigations
6	Method to group meters and send a batch ping to each meter in a cluster (clusters to be defined or made configurable)	Future	May be simulated by a configuration change, possibly
7	Ability to display Low Voltage message indications on supplying transformer on the NMS diagram	Future	Explore configuration with current software
8	Ability to toggle display of Low Voltage Messages on and off from the NMS diagram display	Future	Explore configuration with current software

Weather Sensors

Weather Sensors – Introduction

There are weather sensors that are electronically monitored available from external sources/systems that can be interfaced with NMS to provide additional information to users of the NMS.

SDG&E has approximately 220 weather stations located close to the overhead network. These stations monitor several weather datapoints as shown below:

Fig. 19. Typical Weather Station Details

This data could potentially be accessed by NMS since the weather stations send data at least every 10 minutes. Some data can also be set to temporarily poll much more frequently when needed. Data available includes:

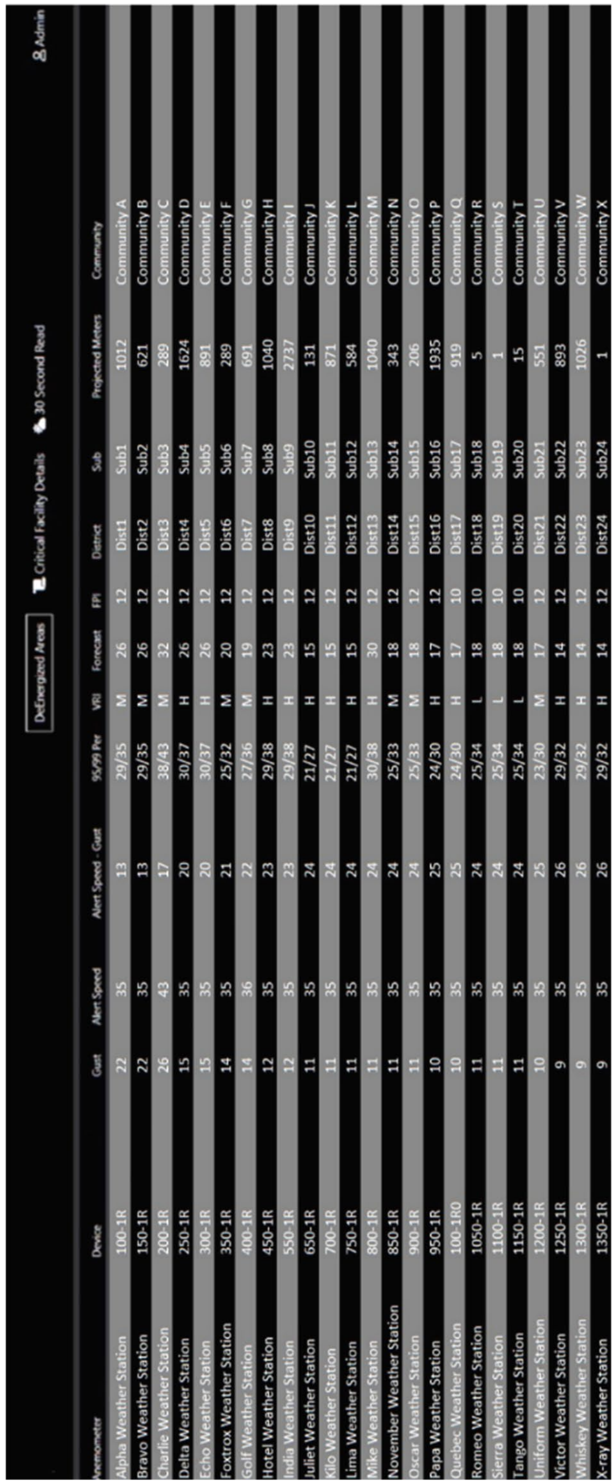
- Station name
- Temperature
- Humidity
- Wind Speed
- Wind Gust
- Wind Compass (N,S,E,W,SE,SW etc.)
- Wind Direction (degrees true)

- Decommissioned
- Latitude
- Longitude
- Retrieval time

Weather Sensors - Data Source Analysis

Weather data is currently used to support processes that improve fault response times and reduce fire risks. The current practice is that when high winds are forecast, patrols are dispatched to areas of high winds to try to position them in the best possible places to locate faults as soon as possible. Lines are also patrolled days in advance of a forecasted event to look for areas of potential trouble. This practice is seasonal, just before and during the times of the year when high winds are expected. If high winds are detected unexpectedly, exceptions will be made, and patrols will be dispatched to these areas. This weather-based dispatching of crews is done proactively and will be done even if no fault has been identified. This is a mitigation strategy that enables crews to get to a fault location as fast as possible. Or, in some cases, avoid a fault from occurring entirely. Faults under these conditions are commonly the result of debris on the lines, vegetation contact, or conductor failure and have a risk of potentially causing fires, as a function of weather and other factors.

Design standards exist for the distribution system that are based upon expected extreme weather conditions and “known local conditions”. However, weather conditions do occur that exceed the design standards (i.e., winds in excess of 100 mph). Weather stations are used to identify areas with a regular history of occurrences of conditions with excessively high winds to use as proactive measures to do additional hardening above the design standards. The accepted design and regulatory guidelines state if weather information is available, then local guidelines can be established that are unique to the conditions in that region. The term used in the regulatory regime is “known local conditions.”



Anemometer	Device	Gust	Alert Speed	Alert Speed - Gust	95/99 Per	VRI	Forecast	FPI	District	Sub	Projected Meters	Community
Alpha Weather Station	100-1R	22	35	13	29/35	M	26	12	Dist1	Sub1	1012	Community A
Bravo Weather Station	150-1R	22	35	13	29/35	M	26	12	Dist2	Sub2	621	Community B
Charlie Weather Station	200-1R	26	43	17	38/43	M	32	12	Dist3	Sub3	289	Community C
Delta Weather Station	250-1R	15	35	20	30/37	H	26	12	Dist4	Sub4	1624	Community D
Echo Weather Station	300-1R	15	35	20	30/37	H	26	12	Dist5	Sub5	891	Community E
Foxtrox Weather Station	350-1R	14	35	21	25/32	M	20	12	Dist6	Sub6	289	Community F
Golf Weather Station	400-1R	14	36	22	27/36	M	19	12	Dist7	Sub7	691	Community G
Hotel Weather Station	450-1R	12	35	23	29/38	H	23	12	Dist8	Sub8	1040	Community H
India Weather Station	550-1R	12	35	23	29/38	H	23	12	Dist9	Sub9	2737	Community I
Juliet Weather Station	650-1R	11	35	24	21/27	H	15	12	Dist10	Sub10	131	Community J
Kilo Weather Station	700-1R	11	35	24	21/27	H	15	12	Dist11	Sub11	871	Community K
Lima Weather Station	750-1R	11	35	24	21/27	H	15	12	Dist12	Sub12	584	Community L
Mike Weather Station	800-1R	11	35	24	30/38	H	30	12	Dist13	Sub13	1040	Community M
November Weather Station	850-1R	11	35	24	25/33	M	18	12	Dist14	Sub14	343	Community N
Oscar Weather Station	900-1R	11	35	24	25/33	M	18	12	Dist15	Sub15	206	Community O
Papa Weather Station	950-1R	10	35	25	24/30	H	17	12	Dist16	Sub16	1935	Community P
Quebec Weather Station	100-1R0	10	35	25	24/30	H	17	10	Dist17	Sub17	919	Community Q
Romeo Weather Station	1050-1R	11	35	24	25/34	L	18	10	Dist18	Sub18	5	Community R
Sierra Weather Station	1100-1R	11	35	24	25/34	L	18	10	Dist19	Sub19	1	Community S
Tango Weather Station	1150-1R	11	35	24	25/34	L	18	10	Dist20	Sub20	15	Community T
Uniform Weather Station	1200-1R	10	35	25	23/30	M	17	12	Dist21	Sub21	551	Community U
Victor Weather Station	1250-1R	9	35	26	29/32	H	14	12	Dist22	Sub22	893	Community V
Whiskey Weather Station	1300-1R	9	35	26	29/32	H	14	12	Dist23	Sub23	1026	Community W
X-ray Weather Station	1350-1R	9	35	26	29/32	H	14	12	Dist24	Sub24	1	Community X

Fig. 20. Tool used to show weather impact and forecasting (rotated to improve readability)

Existing tools used for weather-related fault risk mitigation include a dashboard that provides quick summary information of weather and associated risk factors including VRI (Vegetation Risk Impact) and FPI (Fire potential index). These are calculated based on the geographic information of the locations and the current weather information. Line items are automatically sorted in terms of highest to lowest maximum wind gust.

Asset condition status is also considered in weather-related fault risk analysis. Any equipment that is not at 100% condition (i.e., poles that may be pending replacement, or are under temporary construction configuration) are marked as a candidate for patrol locations in high winds and operators are informed of these sites.

Weather and equipment not in top condition may ultimately result in operations making the decision to de-energize a section of network that may not be currently experiencing faults, but as preventative measures due to fire risk/safety. This practice is used as the last resort when no other mitigation practice is deemed sufficient. In California, this is known as Public Safety Power Shutoff, or PSPS.

Weather Sensors – Data Source Findings

There is an opportunity to integrate weather data and make it readily available to operators using NMS. This would streamline and improve the accessibility of this data enabling weather related fault mitigation decisions to be made faster and based upon more complete information.

In the NMS the following items are recommended:

- Create a new symbol to show the location of each weather station
- Have condition symbols that show locations where wind speed is greater than a pre-configured threshold, temperature and humidity exceed pre-configured high/low thresholds and gusts higher than a pre-configured threshold at the weather station locations.
- Bring dashboard data into NMS and potentially use the data to influence fault location prediction.
- Show FP and VRI heat map directly within NMS viewer.

Advanced Protective Relays

Advanced Protective Relays – Introduction

Protective relays are devices that trip a circuit breaker when a fault is detected. Early protective relays were electromechanical devices. To protect the distribution equipment on a circuit, protective relays often need to respond and trip a breaker within a few thousandths of a second. Advanced Protective Relays (ARP) are microprocessor-based devices that mimic the behavior of the original electromechanical protection devices. The microprocessor based protective relays are more flexible and have many advantages over the older electromechanical devices. In addition to the savings associated with lower maintenance costs and flexibility, the microprocessor-based relays are often coupled with communications equipment, enabling them to provide data back to a centralized location.

Advanced Protective Relays - Data Source Analysis

SDG&E utilizes advanced protective relays extensively in the protection and control of their distribution and transmission grids. Advanced protective relay manufacturers provide software tools that allow users to analyze system conditions and determine the root cause of relay operations. Event reports from an advanced protective relay contain the date, time, current, and voltage information and the status of multiple relay word bits. An event report can be triggered manually or by predefined programmable logic. Once an event is triggered, the essential data to understand and troubleshoot the system operation are archived for retrieval and analysis. These event archives can be viewed using the proprietary APR software. The following are two file types that APR event viewer software imports for event analysis [4]:

1. Compressed Event Report (CEV)
2. Common Format for Transient Data Exchange for power system (COMTRADE)

The compressed event report (CEV) is unique to APR devices. However, COMTRADE files comply with IEEE C37.111 [5]. This standard allows system events to be digitally stored in a common format. Compressed event reports are essential when analyzing system events, but COMTRADE files can provide additional benefits. Following the current process in the SDG&E operation, per each event these CEV files will be created by APRs and distributed to the different teams: such as operators, protection and control engineers, etc., as shown in **Fig.21**.

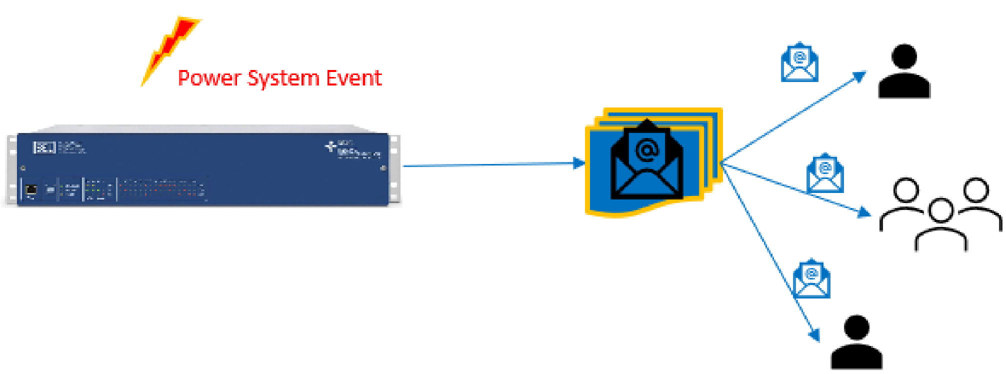


Fig. 21. Submission of CEV file distribution, per each power grid event.

The goal of the investigation was to determine how the information of these CEV files can be helpful for the online operation of the power distribution network by the NMS.

Advanced Protective Relay (APR) File Configuration

To read and visualize the APR files, proprietary software is required to view the following components and capabilities (in basic and advanced):

- Analog and digital charts,
- Harmonic and spectral analysis,
- Phasor value derivation and display,
- Automatic calculation of symmetrical components,
- Reconfigurable display,
- ACB or ABC phase rotation support,
- Searchable signal lists and relay settings,
- View COMTRADE ASCII format event reports.

Sample Advanced Protective Relay File

One sample APR file had been selected to read and investigate in detail.

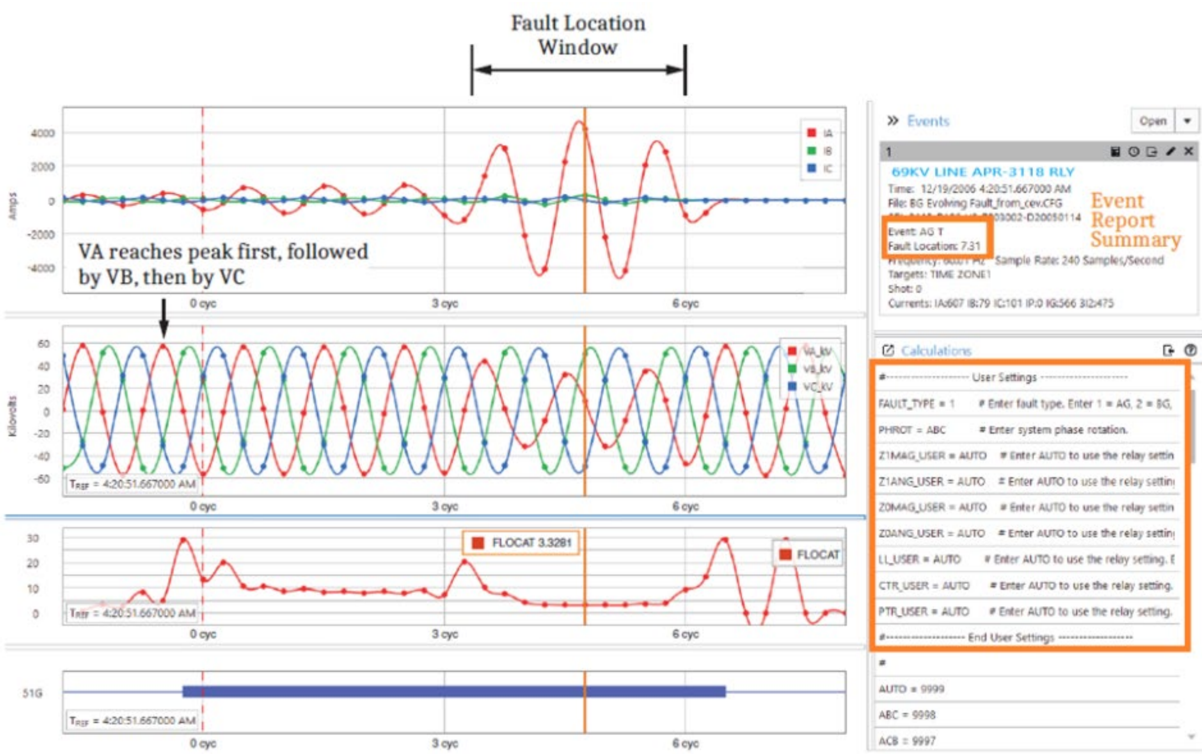


Fig. 22. Sample Advanced Protective Relay file, reference: [3]

In the example in **Fig. 22**, you can tell that the fault evolved from a high resistance to a bolted fault, based on the fact that the A-phase current was only slightly greater than the other phase currents at the beginning of the report and then dramatically increased around Cycle 3.25. That is why we designate Cycle 3.25 as the start of the fault location window. Cycle 6, when the fault is interrupted, marks the end of the fault location window.

In this example, the custom calculations estimate the fault location to be 3.33 miles from the relay. The actual fault location was 3.6 miles from the relay. The event summary shows that the relay estimated the fault to be 7.31 miles away from the relay, meaning that the fault location error was 3.71 miles. Because the relay does not have the benefit of human analysis when determining a fault location, its ability to accurately perform the steps described in this section is limited during an evolving fault. The relay uses the status of fault detectors, typically overcurrent and distance elements, to determine how long the fault was present and the length of the fault location window. Then it calculates fault location with voltage and current data in the middle of that window. In this case, the fault initially started as a high-impedance fault. Relay word bit 51G asserted at around Cycle 0 in Figure 22. It de-asserted when the breaker opened and interrupted the fault at around Cycle 6.5. This resulted in the relay using a fault location window of 6.5 cycles. Notice that right at the middle of this window, the fault evolved from a high resistance to a bolted fault. This dramatic evolution of the fault and its unlikely timing led to the significant fault location error from the relay. Challenging faults like this require manual analysis. These settings are used to calculate the positive and zero-sequence line impedance in primary ohms per unit line length.

This example highlights the importance of the quality of each impedance value and correct configuration of Advanced Protective Relays to detect and identify power system faults.

SDG&E's Advanced Protective Relay files

SDG&E team provided their sample relay files at its distribution networks, as shown in **Fig. 23**:

D SUB-C CIR3 APR-351 2014 Aug 03 12 08 57 663 1.cev	CEV Relay Event file
D SUB-R CIR6 APR-351 2020 Oct 12 08 45 04 659 10230.cev	CEV Relay Event file
D SUB-R CIR6 APR-351 2020 Oct 12 08 45 25 496 10233.cev	CEV Relay Event file
D SUB-C CIR3 APR-351 2014 Jul 11 01 11 22 294 3.cev	CEV Relay Event file
D SUB-C CIR3 APR-351 2014 Jul 11 03 10 22 303 2.cev	CEV Relay Event file
D SUB-R CIR6 APR-351 2021 Jan 19 22 16 19 325 10275.cev	CEV Relay Event file
D SUB-R CIR6 APR-351 2021 Jan 20 00 37 36 576 10276.cev	CEV Relay Event file
D SUB-S CIR2 APR-351-6 2020 May 20 14 10 31 277 10417.cev	CEV Relay Event file
D SUB-S CIR2 APR-351-6 2020 May 20 14 10 33 835 10418.cev	CEV Relay Event file

Fig. 23. Sample Advanced Protective Relay files

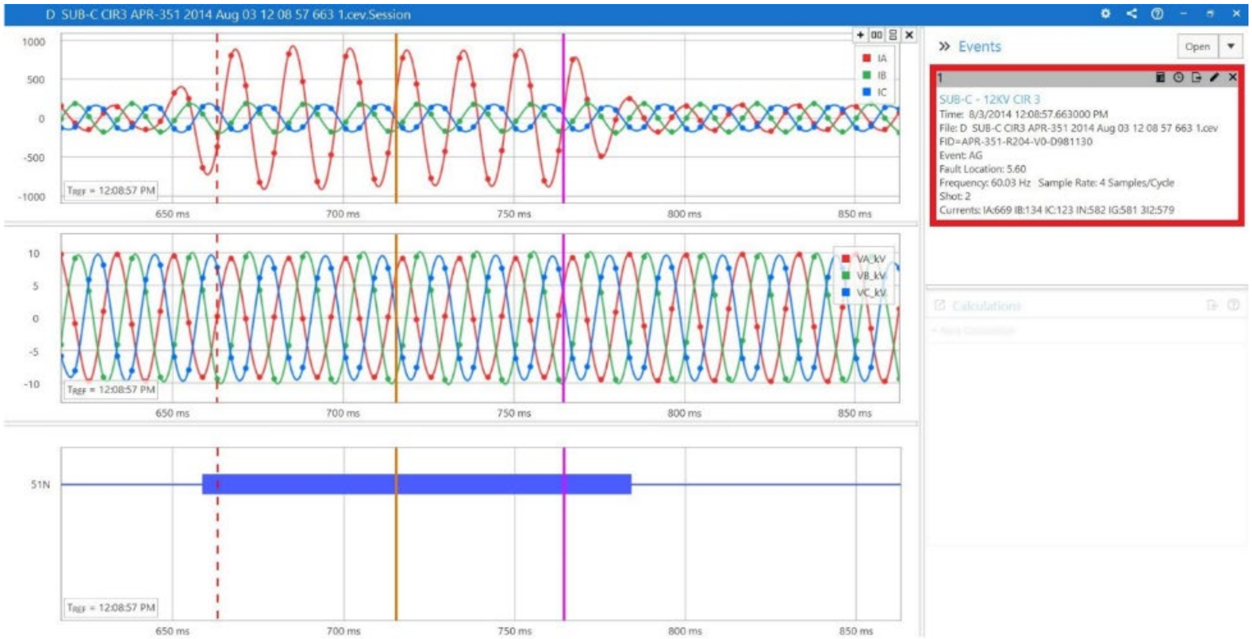


Fig. 24. Sample Advanced Protective Relay file for A-351 at 2014 Aug 03.

The figure above shows the single phase to ground (AG) event on an SDG&E circuit on Aug. 03, 2014. In the summary of this file, this information can be parsed:

- Affected System: C 12 kV CIR-3
- Event Time: 8/3/2014 12:08:57.663000 PM
- Relay Name: FID=APR-3-R2
- Event Type: AG
- Fault Location: 5.60 miles
- Frequency of Measurements: 60.03 Hz   Sample Rate: 4 Samples/Cycle
- Shot: 2
- Event Currents: IA:669 IB:134 IC:123 IN:582 IG:581 3I2:579

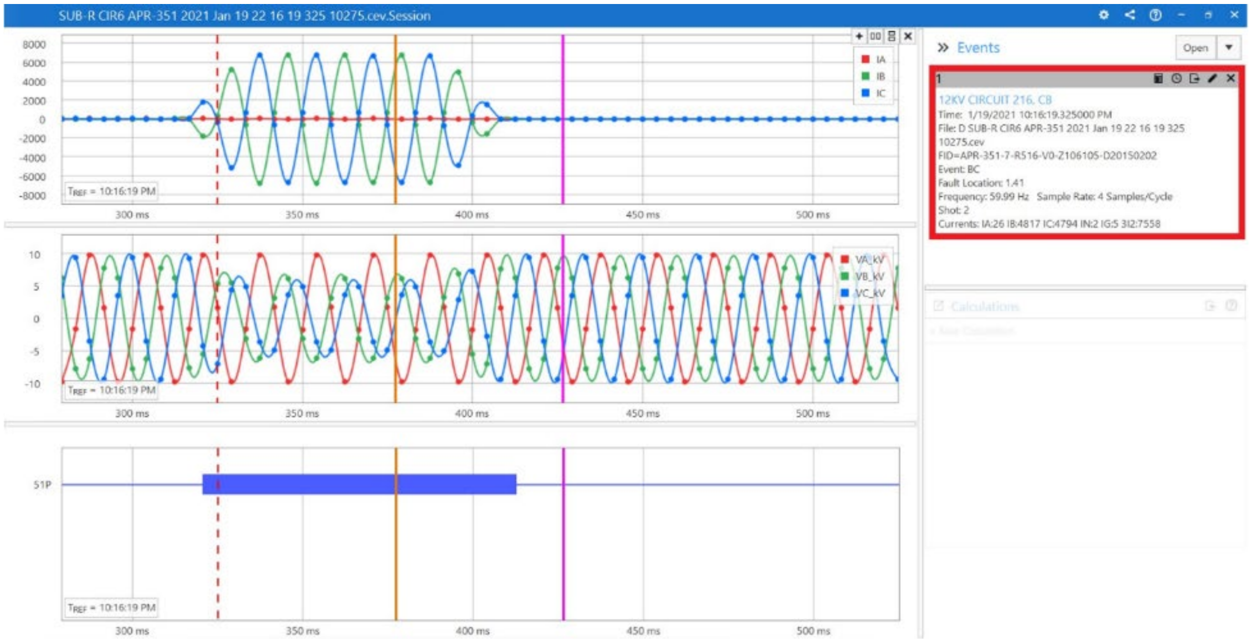


Fig. 25. Sample Advanced Protective Relay file for APR-351 at Jan 19, 2021.

A more recent Advanced Protective Relay file is shown in **Fig. 25**. The event was recorded on Jan. 19th, 2021, at one of the SDG&E distribution feeders, the summary of the event:

- Affected System: 12 kV CIR 6, CB
- Event Time: 1/19/2021 10:16:19.325000 PM
- Relay Name: FID=APR-3-R5
- Event Type: BC
- Fault Location: 1.41 miles
- Frequency of Measurements: 59.99 Hz   Sample Rate: 4 Samples/Cycle
- Shot: 2
- Event Currents: IA:26 IB:4817 IC:4794 IN:2 IG:5 3I2:7558

For both events, the affected system, time of the event, detected relay, type of the event, location of the event, the frequency of measurements with sample rate including shots, and finally event (fault) currents are reported. The format of the file is text ASCII, and this information can be parsed from the body of the file.

Advanced Protective Relay – Data Source Findings

After an internal review of a sample of SDG&E's Advanced Protective Relay files and a meeting with the Protection & Control team of SDG&E, these observations have been identified:

- Due to the complexity of distribution system modeling in SDG&E's service territory, the impedance values for each distribution system phase and their mutual impedance are not accurate enough to determine the fault location properly by using Advanced Protective Relay methodology.
- Impedance models can be changed due to the "Switching Events," which can change the whole circuit impedance model.

- Current settings are based on the fault short circuit duties in the distribution system, not based on impedance calculation and model, which is common on transmission system short circuit modeling and calculation.

Table 6 compares the relay file information with SCADA information regarding the distribution faults.

Table 6 Advanced Protective Relay file information vs SCADA for distribution faults

Inputs	APR files	SCADA	Note
Affected System	Yes	Yes	
Event Time	Yes	Yes	
Reported/ Operated Relay	Yes	Yes	
Event Type	Yes	Yes	
Fault Location	Yes	No	Currently it is not reliable; it should be configured with accurate impedance values.
Event Fault Currents	Yes	Yes	

In conclusion, with the current settings of the Advanced Protective Relay, fault location information is not reliable for the operation purposed due to the aforementioned reasons. In the future, with detailed and accurate impedance models for distribution networks, this feature can be utilized in the ADMS/NMS. In addition, further investigations will be needed to determine the value by considering the communication network latency to integrate with ADMS/NMS solution.

Phasor Measurement Units

Phasor Measurement Units – Introduction

This section describes the applications and analysis of distribution-level Phasor Measurement Unit (PMU) data, deployed across a few feeders in the service territory.

A PMU is an instrument that measures the voltage and/or current waveforms of the electrical power system. SDG&E has deployed many PMUs across its service territory. The measurements are synchronized to a global time standard, Coordinated Universal Time (UTC), using GPS technology.

PMUs digitize the input waveforms, usually all three phases. These digital samples represent the analog input signals as numerical values, which are processed by the PMU. The PMU calculates the amplitude and a phase angle; these two quantities are known as a phasor. The waveforms are sampled and synchronized with a global time base and each phasor is marked with a time code. The combined result is known as a synchrophasor.

The voltage and current waveforms are sampled by using an Analog-to-Digital Converter (ADC). An ADC takes an input and transforms it into a series of numerical values at discrete instances in time. This process is known as sampling, and the series of numerical output data from the ADC are known as sampled values (SV) as shown in ***Fig. 26***

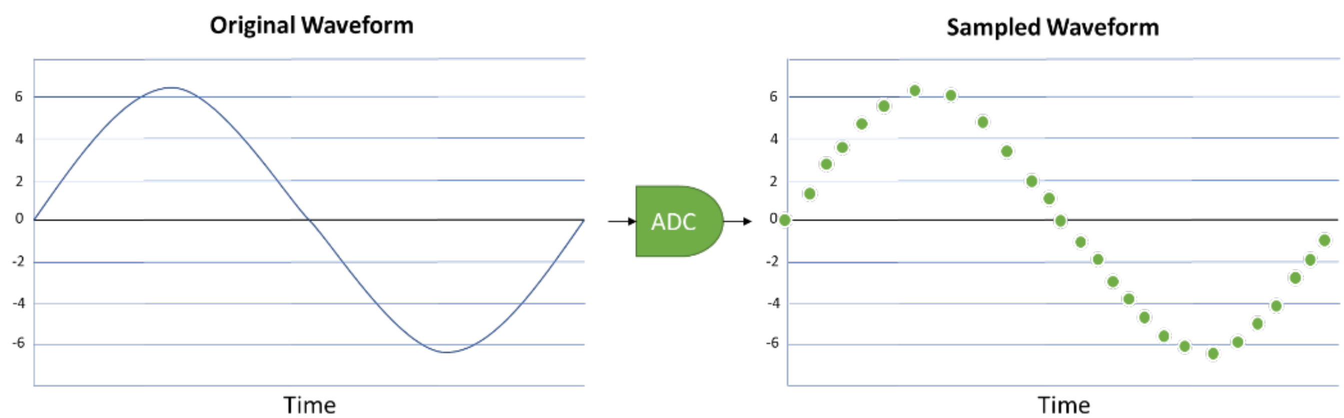


Fig. 26. ADC Process: Sampled Values from Original Waveforms

The difference between the numerical value produced by the ADC and the original waveform is known as the quantization error. The quantization error may be reduced by increasing the bit-depth of the ADC. The required sampling rate is a subject of the Nyquist-Shannon sampling theorem. In brief, one must sample it "at least twice" the frequency of the maximum frequency one wishes to recover. In practice, it is necessary to sample at significantly higher frequencies than the "Nyquist rate." A phasor represents two of the parameters of a sinusoidal waveform, described below:

$$x(t) = A_m \cos(2\pi f t + \varphi)$$

where $x(t)$ is the amplitude of the waveform at time t, A_m is the amplitude of the waveform, f is the frequency, and φ (phi) is the phase angle. Phase must be measured between two things. In the PMU, the phase is measured between the applied signal and a hypothetical reference signal whose frequency is exactly the nominal value of the power system (50 or 60 Hz) and whose cosine peaks at exactly the "tick" of the second of the UTC time base. The objective of the phasor estimator is to adjust the parameters A_m, f and φ until the resulting waveform matches the acquired sample values, as shown in *Fig. 16.*

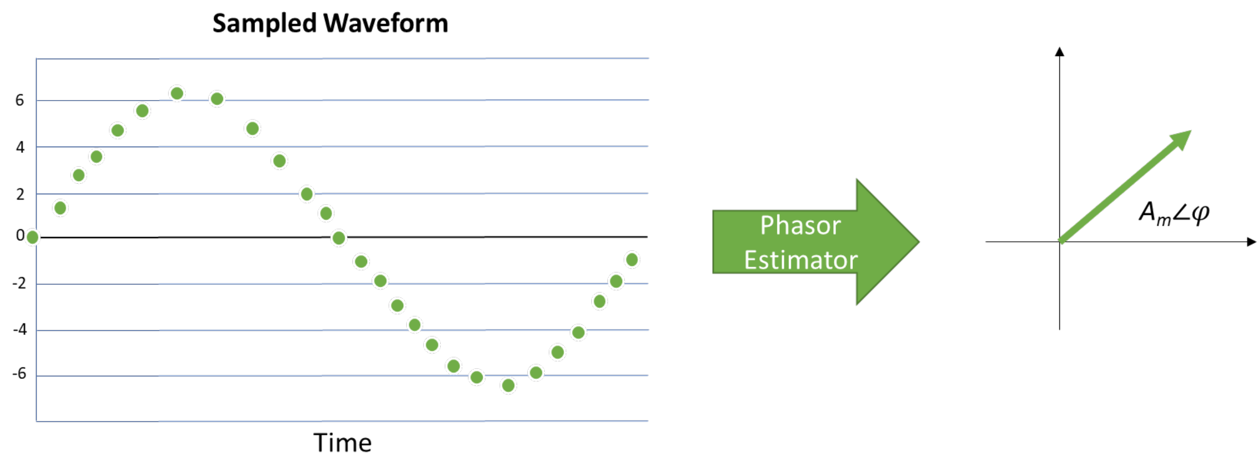


Fig. 27. Phasor Estimator

PMU Applications Background

Historically, electric grid planners and operators had limited information for understanding the status and behavior of the electric grid. Available information included measurements from supervisory control and data acquisition (SCADA) systems, typically available at several-second intervals from substations, and model data based on equipment ratings and specifications. The physical state variables of the AC network–specifically, the complex voltages, or time-shifted voltage waveforms at every node–were not directly observable but could be estimated through these models. This solution worked well enough for many years. But given the growing uncertainties and complexities in grid planning and operations, these methods are increasingly becoming inadequate in time resolution, precision, accuracy, and scope [7].

Transmission planners and operators were the first to recognize the need for new tools that rely on advanced sensors and more comprehensive monitoring to better observe, understand, and manage the grid. The challenge in transmission systems was comparing measurements across long distances (hundreds of miles) that would reveal physical interactions such as oscillations between generators and be able to describe power flows and stability across an entire synchronous AC network. By comparison, distribution systems were simple and posed little need to observe their operation with much granularity in space or time.

With the rapid growth in deployment of distributed energy resources, two-way electricity flows and new customer devices such as electric vehicles, there is a growing interest in sharper observation tools for the distribution grid. The possibility of unanticipated interactions among new and legacy devices, along with opportunities for more active and intelligent control, delivers value from measurements that are both precise and time-synchronized, making electrical events and responses observable and comparable between locations.

A high-value grid monitoring system will possess several characteristics:

- A high degree of time granularity, on the order of a sample per cycle or better, compared to current SCADA and EMS, which provides samples every few seconds.
- Fast communications access for real-time streaming of data for system recovery following disturbances.
- High-resolution data for off-line engineering analysis, and preferably in near real-time to enable operation support analytics.
- Deployment of many measurement devices across the system, which implies both low-cost devices and installation.
- Precise time synchronization of measured data to enable comparison across many electrical locations on the grid.
- Data quality, availability and volume that are appropriate to serve the high priority uses and monitoring needs of operational and planning functions and tools.

A substantial fraction of electric utilities' financial and capital assets is spent on distribution networks. Despite good design, installation, operation, and maintenance efforts, over 90% of customers' electric outages occur due to problems occurring on the distribution system (rather than from transmission-level or generation-level issues). Yet many North American utilities have limited amounts of monitoring on their distribution systems. Typically, there are some SCADA devices on sub-transmission elements and a growing number of advanced meter deployments that provide 15-minute power or energy readings (although often with delayed data delivery).

It is difficult to know what is happening on the distribution system without monitoring and measuring distribution-level and grid-edge activity. Distribution system managers could use high-quality, high-speed, wide-scale distribution-level monitoring (as feasible from a distribution-tailored synchrophasor network), planners and operators could use the data and appropriate analytical tools for many purposes including:

- State or condition monitoring of the distribution system.
- Monitoring and analysis of customer-owned, behind-the-meter distributed generation and energy storage devices, enabling better forecasting and integration of those devices.
- Measurement and verification of customers' energy efficiency, demand response and load management activities (subject to appropriate privacy protections).
- Monitoring and analysis of significant end-user loads (for example, clusters of electric vehicle chargers).
- Identification of asset and equipment problems, including detection and advance warning of equipment operational issues and failures.
- Fault detection (including high-impedance faults), location and event forensics.
- Anomaly detection, including potential cyber-intrusions.
- Detection of previously unknown dynamic events (for example, control instabilities or oscillations) that are not recognizable with traditional monitoring.

Phasor Measurement Units - Data Source Analysis

The PMU data is collected by a PMU Data Concentrator (PDC) using an industry standard approach [8]. This work sets the foundation for a deeper dive analysis to evaluate whether the gathered data is sufficient to meet the requirements of several key use cases including:

- High-Accuracy fault detection and location
- Advanced distribution protection and control

The PMU data will be explored in two parts in the following sections: (1) no disturbance in grid operation and (2) incidence in grid operation.

PMU Data without Disturbance

Circuit 5 has been selected for further investigation. The circuit has one circuit breaker and four reclosers as well as two tie-switches, as shown in **Fig. 28.**

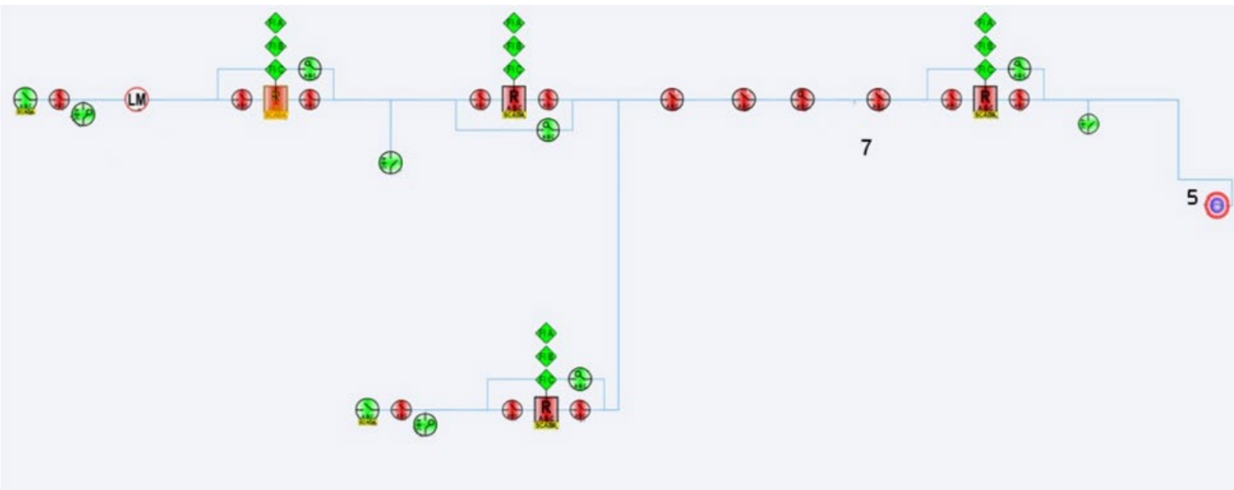
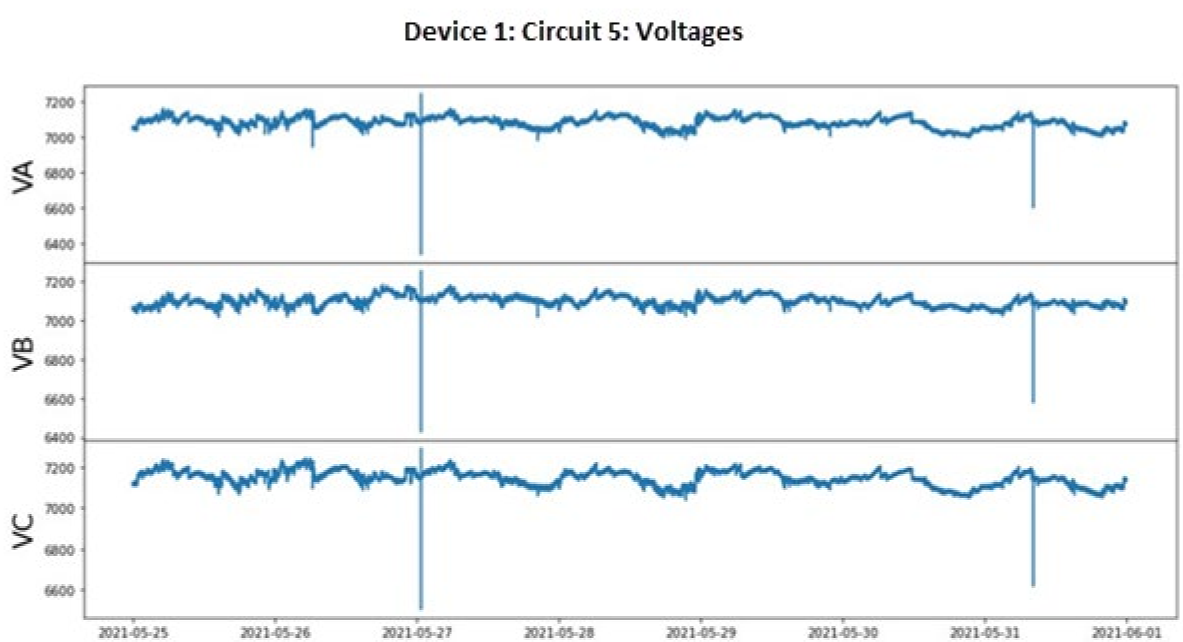


Fig. 28. Circuit 5

The PMUs are placed at the beginning of the circuit and at the tie-switches. The measurements are captured from May 25, 2021 to May 31, 2021.



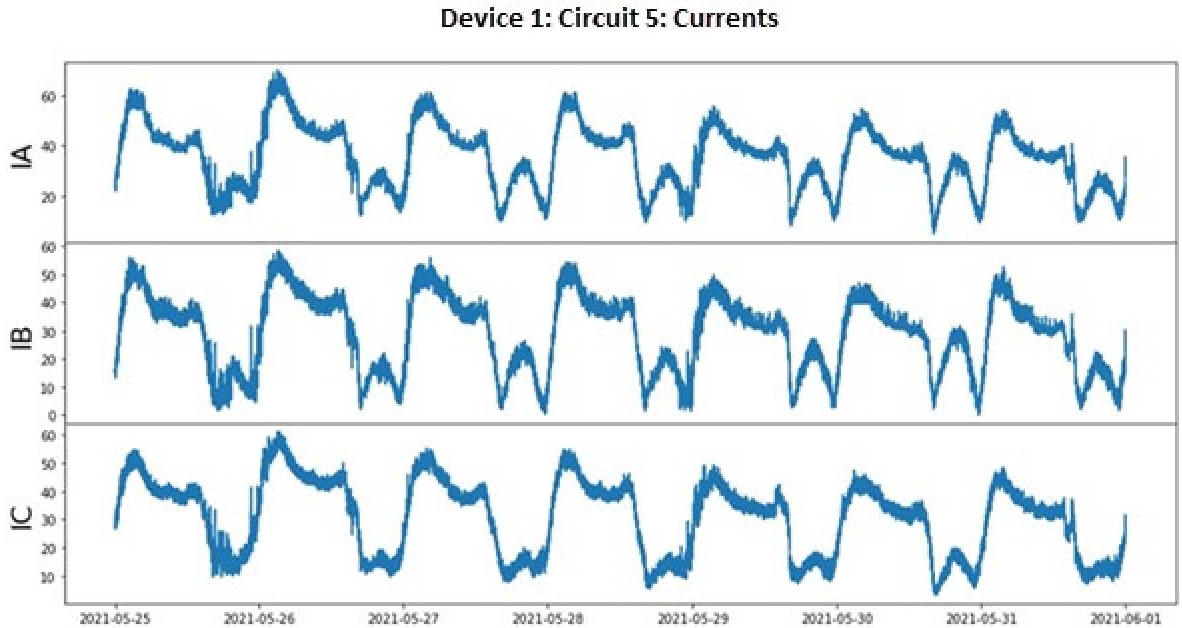
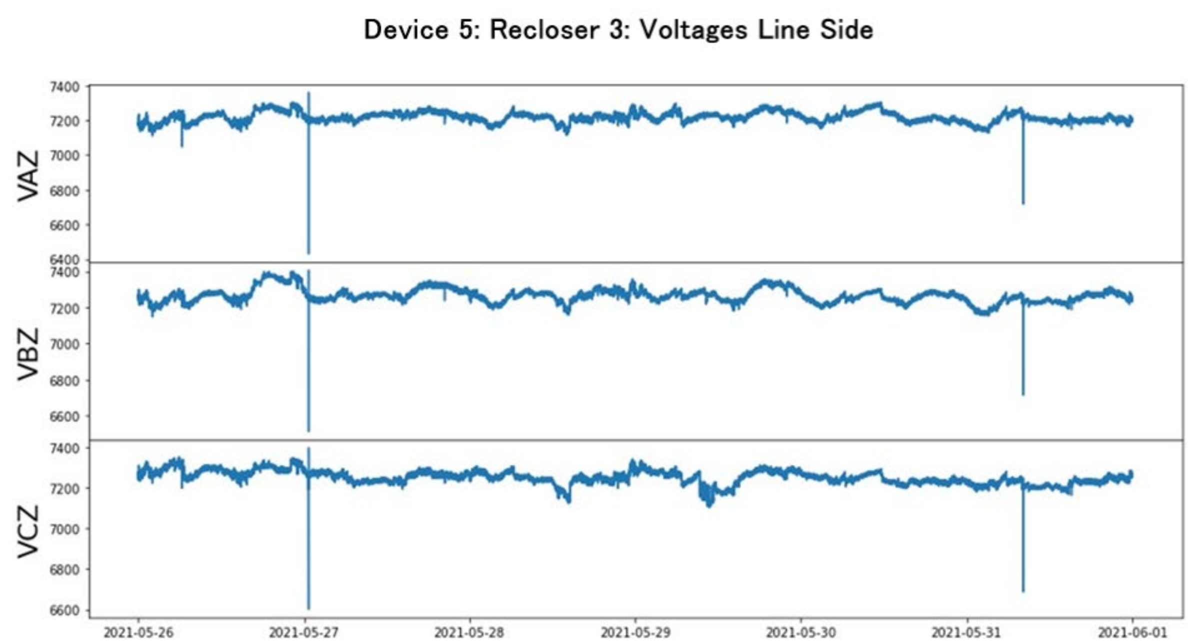


Fig. 29 Voltage and Current Measurements from PMU at Circuit 5's circuit breaker

PMU measurements at Circuit 5's circuit breaker for current and voltage magnitude are presented in **Fig. 29**. As can be seen no major power system incident can be detected.

Along this distribution circuit, PMU measurements at the Recloser 3 for current and voltage magnitude are presented in **Fig. 30***.* A similar pattern has been observed for the Recloser 4 in **Fig. 31** with lower loading condition.



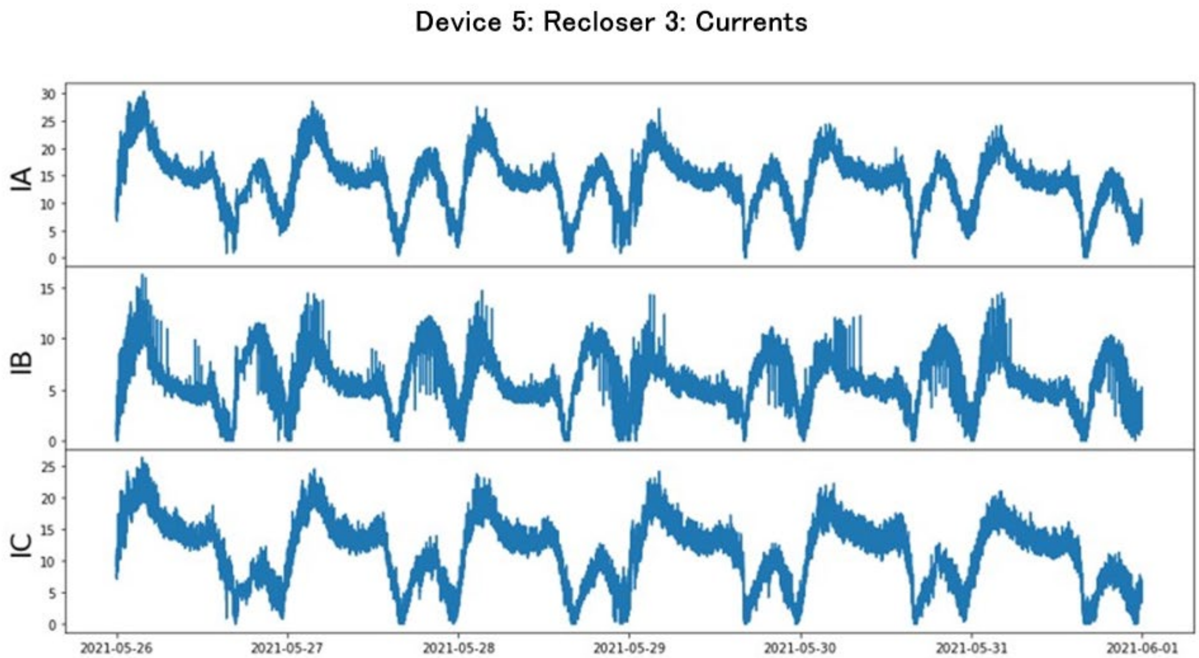
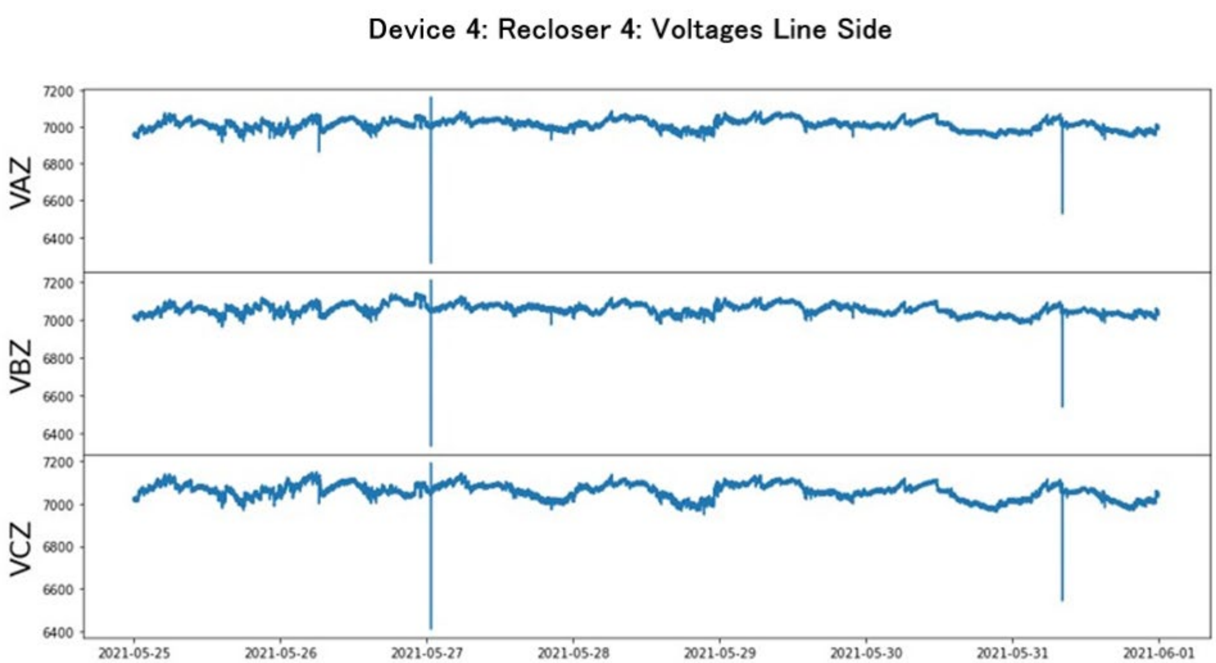


Fig. 30. Voltage and Current Measurements from PMU at Recloser 3.



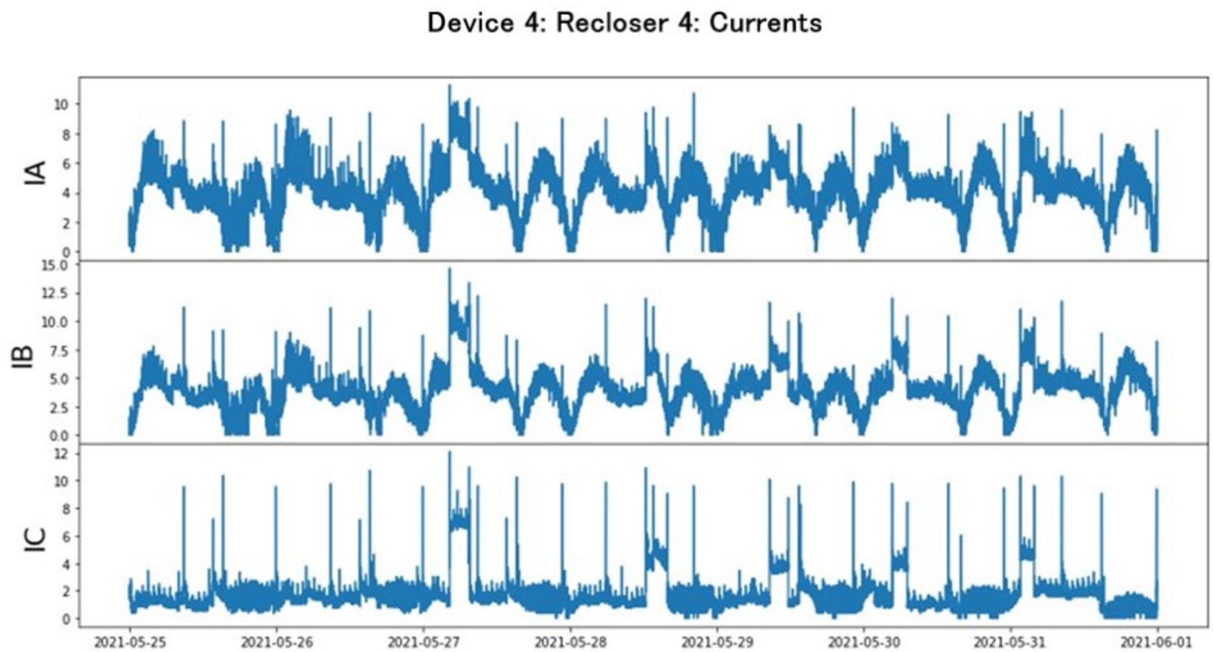
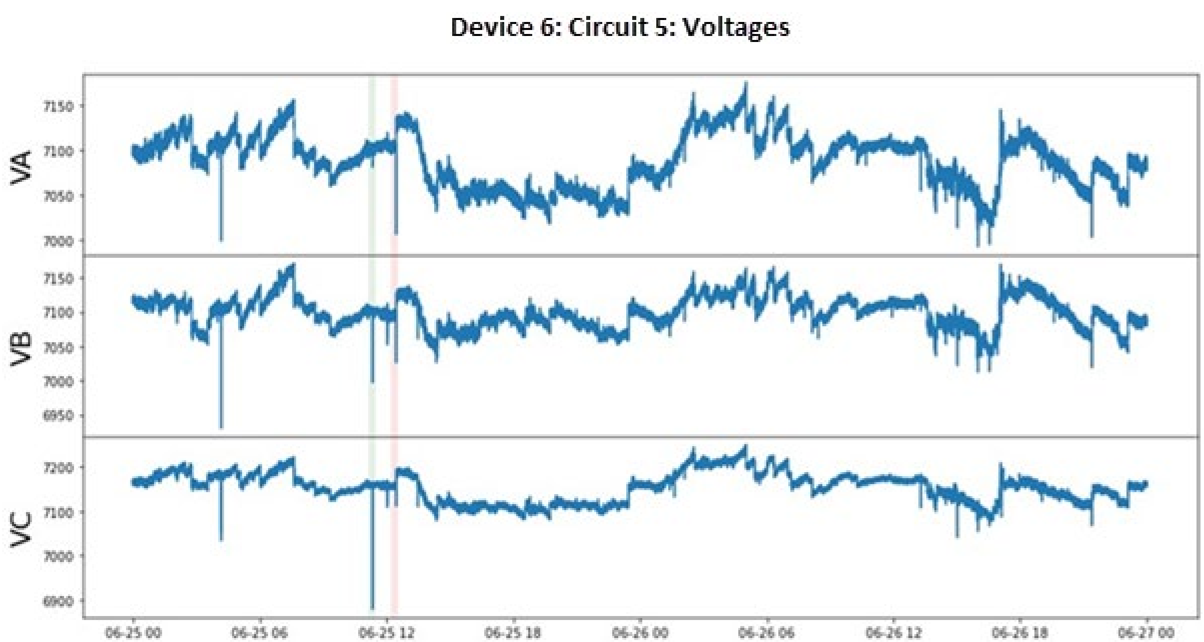


Fig. 31. Voltage and Current Measurements from PMU at Recloser 4.

To check any switching event, PMU measurements at one of the Tie-Switches (T1) for current and voltage magnitude are shown in **Fig. 32**. This Normally Open (N.O.) switch had not closed and current values remained at zero for this period.



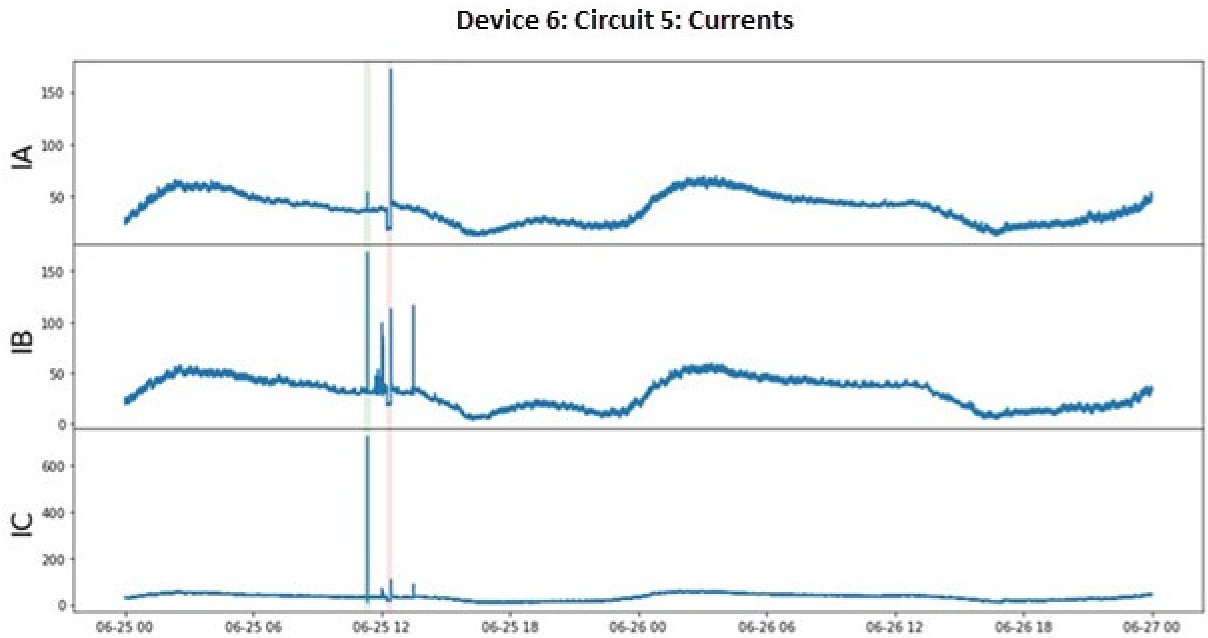


Fig. 32. Voltage and Current Measurements from PMU at Tie-Switch T1.

As can be seen from these previous measurement sets, no events occurred between May 25 to May 31, 2021 on Circuit 5.

In the next section, PMU measurements will be analyzed during an event on the circuit.

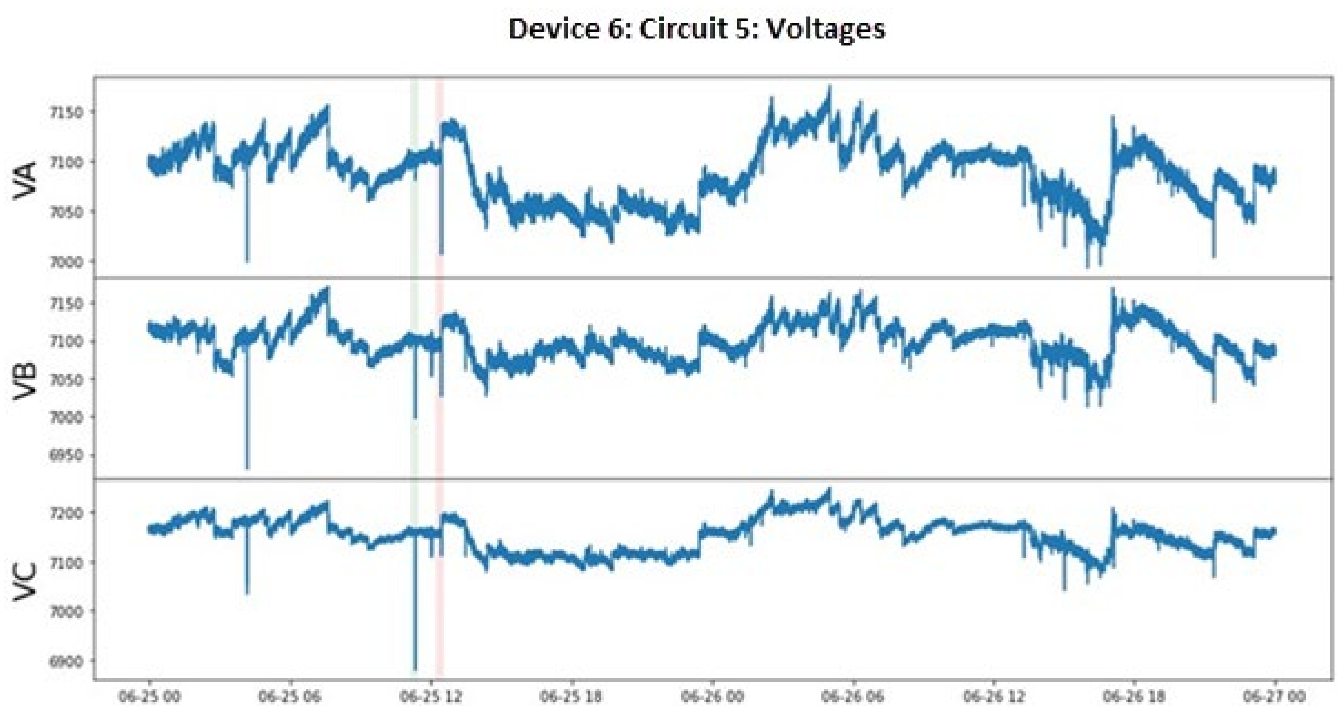
PMU Data with Disturbance

At 5:17 AM, June 25, 2021, SDG&E customers called and reported a fire on one of the poles (P5) associated with Circuit 5. Here, PMU measurements for different devices during this incident were investigated as shown in the details below. It is also worth noting that any of the protective devices along the feeder had not cleared the fault automatically. An operator opened Recloser 2 by SCADA. The series of events were extracted from the NMS has shown in **Fig. 33.**

	Version	Operation	Device	Structure	Details	Status	Instructed Date
Default	1						
1	1	CAUSE	Fuse 3	Pole 5	ETS REPORTS C/O WAS ON FIRE ON POLE 5 - NEED TO DE-ENERGIZE FOR SAFETY	Completed	06/25/21 5:17
2	1	Open by SCADA	Recloser 2	Pole 6	DE-ENERGIZED FOR SAFETY	Completed	06/25/21 5:14
3	1	Block Sensitive Ground Protection	Recloser 3	Pole 7	SS#12	Completed	06/25/21 5:15
4	1	Block Sensitive Ground Protection	Recloser 2	Pole 6	SS#24	Completed	06/25/21 5:15
5	1	Block Sensitive Ground Protection	Recloser 5	Z61	SS#48	Completed	06/25/21 5:16
6	1	Open	Fuse 3	Pole 5	CENTER PHASE FUSE WAS BURNING BUT DID NOT BLOW OPEN - OK TO OPEN REMAINING 2-50A FUSES	Completed	06/25/21 5:25
7	1	Close by SCADA	Recloser 2	Pole 6	RESTORING PARTIAL SERVICE	Completed	06/25/21 5:26
8	2	OK to Patrol	Fuse 3	Pole 5		Completed	06/25/21 5:29
9	3	Remarks	#2 AR BC 118.2		ETS REPORTS ROLLED F/I GOING SOUTH AT POLE 8, BUT NOTHING FOUND	Completed	
10	3	Close	Fuse 3	Pole 5	3-50A FUSES RESTORING ALL SERVICE	Completed	06/25/21 5:23
11	4					Completed	
12	4	Block Sensitive Ground Protection	Recloser 5	Z61	SS#48	Completed	06/25/21 5:43
13	4	Block Sensitive Ground Protection	Recloser 2	Pole 6	SS#24	Completed	06/25/21 5:43
14	4	Block Sensitive Ground Protection	Recloser 3	Pole 7	SS#12	Completed	06/25/21 5:44

Fig. 33. NMS Incident Report for June 25th, 2021

PMU measurements at Circuit 5's circuit breaker for current and voltage magnitude are presented in **Fig. 34.** *.*



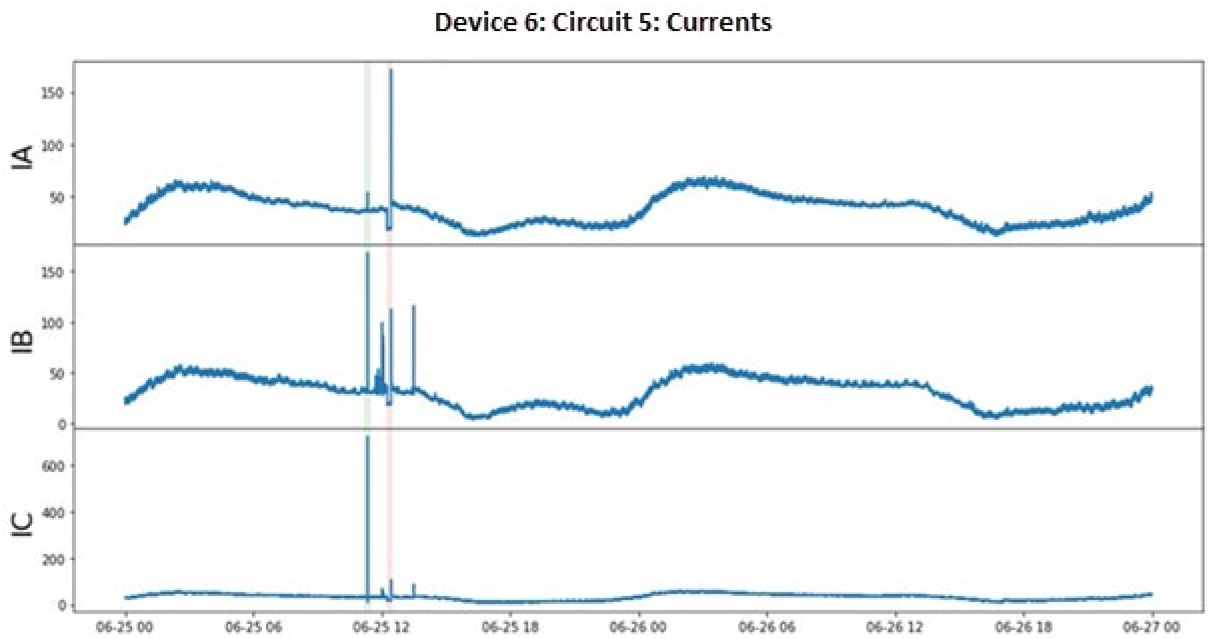
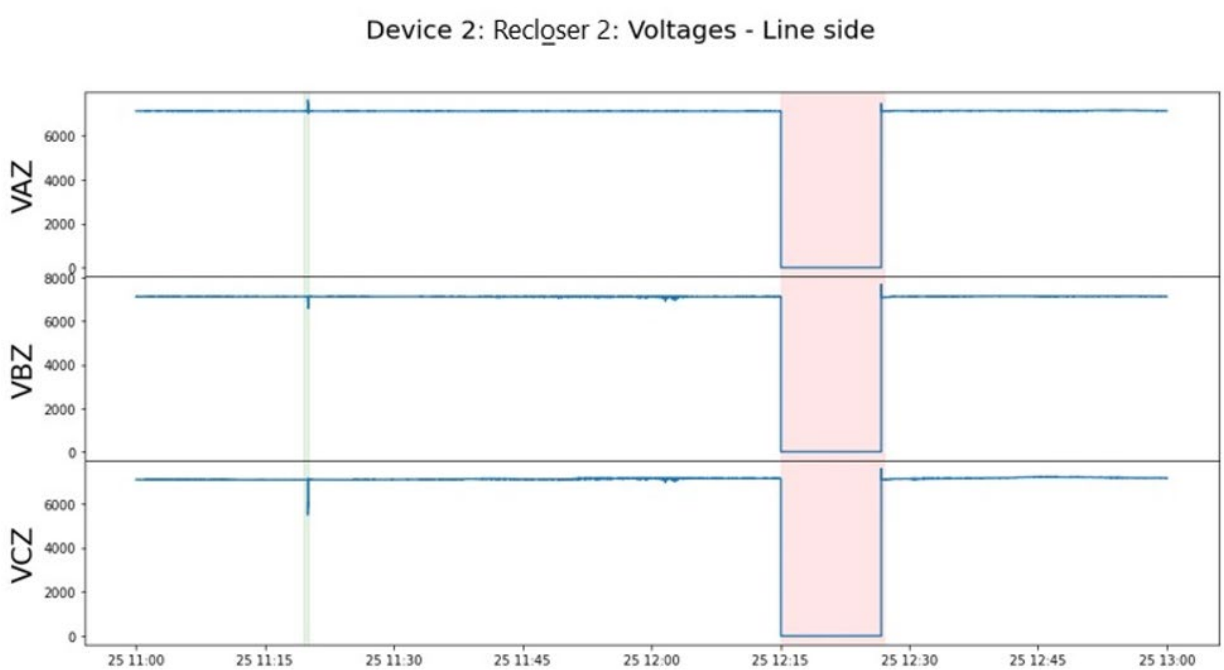


Fig. 34. Voltage and Current Measurements from PMU at Circuit Breaker Circuit 5's circuit breaker for June 25 and 26, 2021.

As shown in **Fig. 35** current spikes can be detected along with voltage drop, light green and red boxes in the Figure. Accordingly, the relay setting circuit breaker could not pick up the fault and clear it, i.e. high impedance fault.



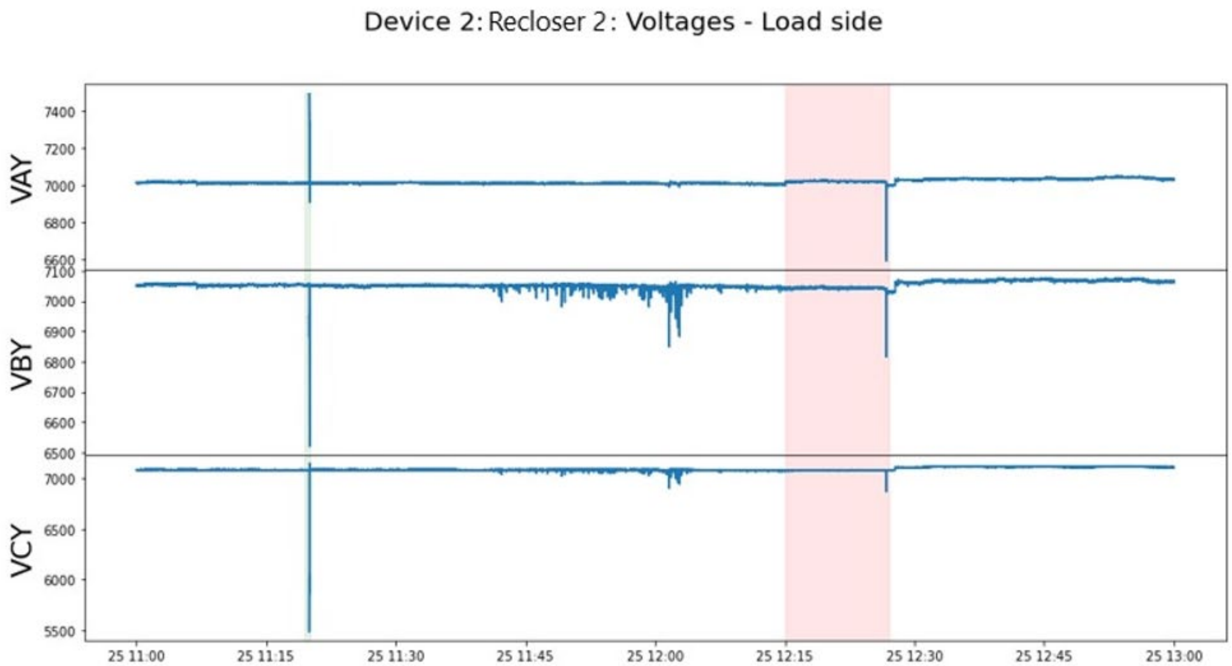


Fig. 35. Voltage Measurements from PMU at the Recloser 1531R for June 25, 2021 in two hours window for both sides: Line and Load.

To investigate in more detail, the PMU measurements near to the incident were explored. **Fig. 36** presents the voltage values in two hours windows for both the line side and load side.

The initial incident has started by highlighting in green and opening of the Recloser 2 is highlighted in red for about 10 minutes. The Line Side voltage had dropped to zero by opening the associated recloser. With this action, the recloser downstream of 2, Recloser 3 had been opened as well.

Along with the distribution Circuit 5, PMU measurements are available from at the Recloser 4 in parallel operation with the Recloser 2. **Fig. 36** shows the voltage values at both Load and Line sides. The voltage variations during the initial incident and switching can be seen in the green and red shading.

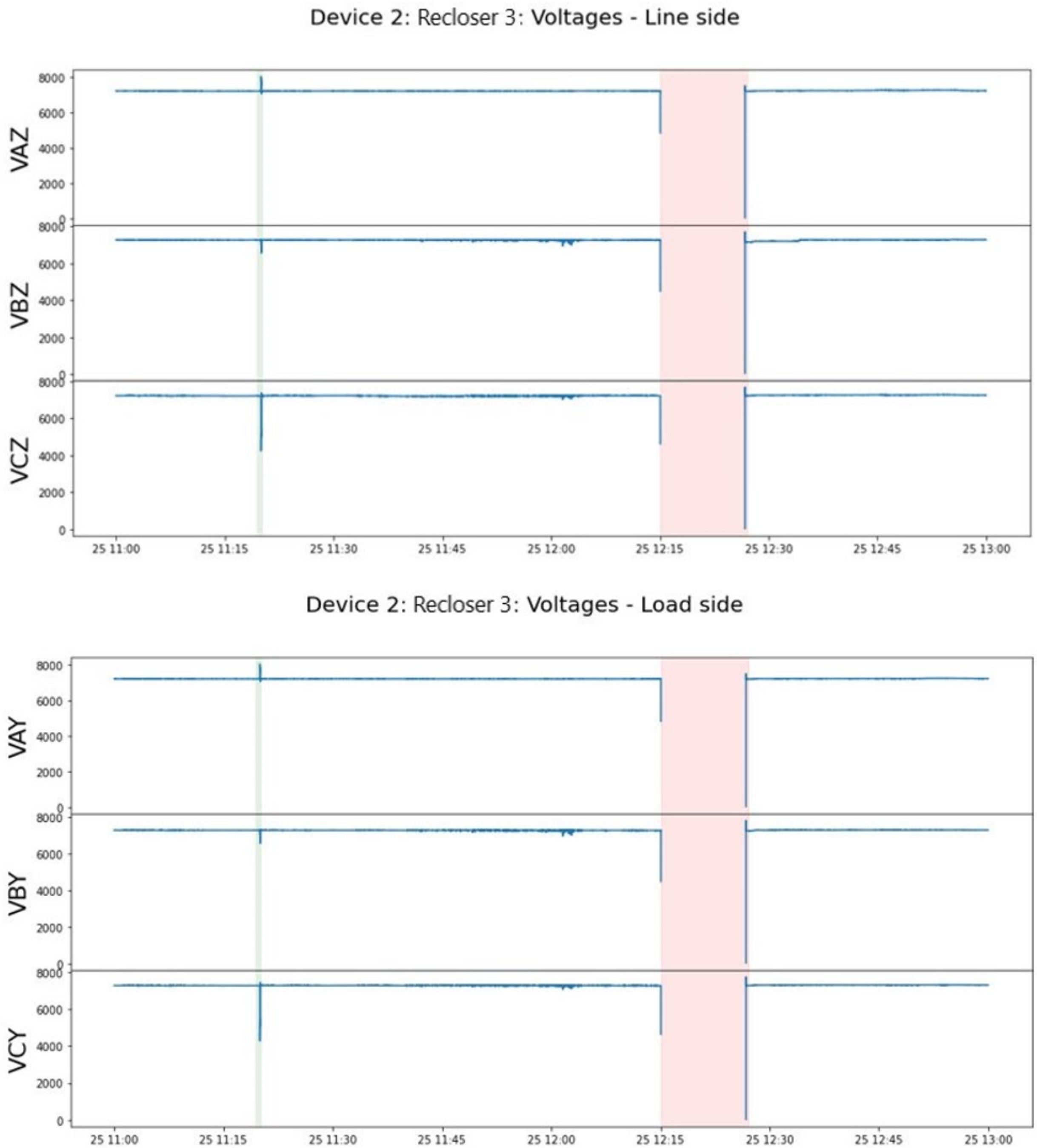


Fig. 36. Voltage Measurements from PMU at the Recloser 2 for June 25, 2021 in two hour windows for both sides: Line and Load.

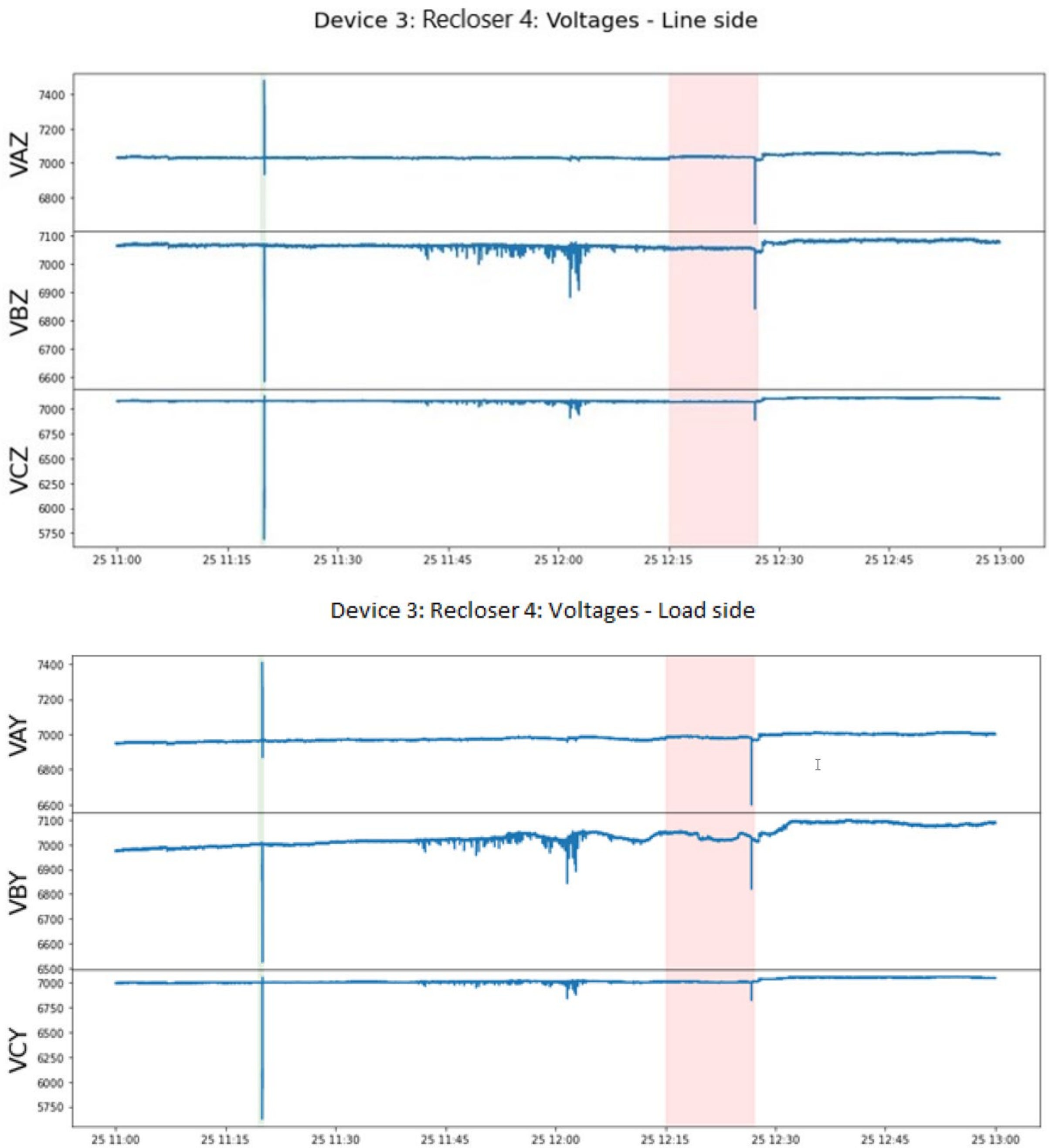


Fig. 37. Voltage Measurements from PMU at the Recloser 4 for June 25, 2021 in two hour windows for both sides: Line and Load.

The location of the incident (fault), the upstream Recloser 4, the downstream recloser 3, the other path Recloser 4, and Circuit 5's circuit breaker are depicted in **Fig. 38.**

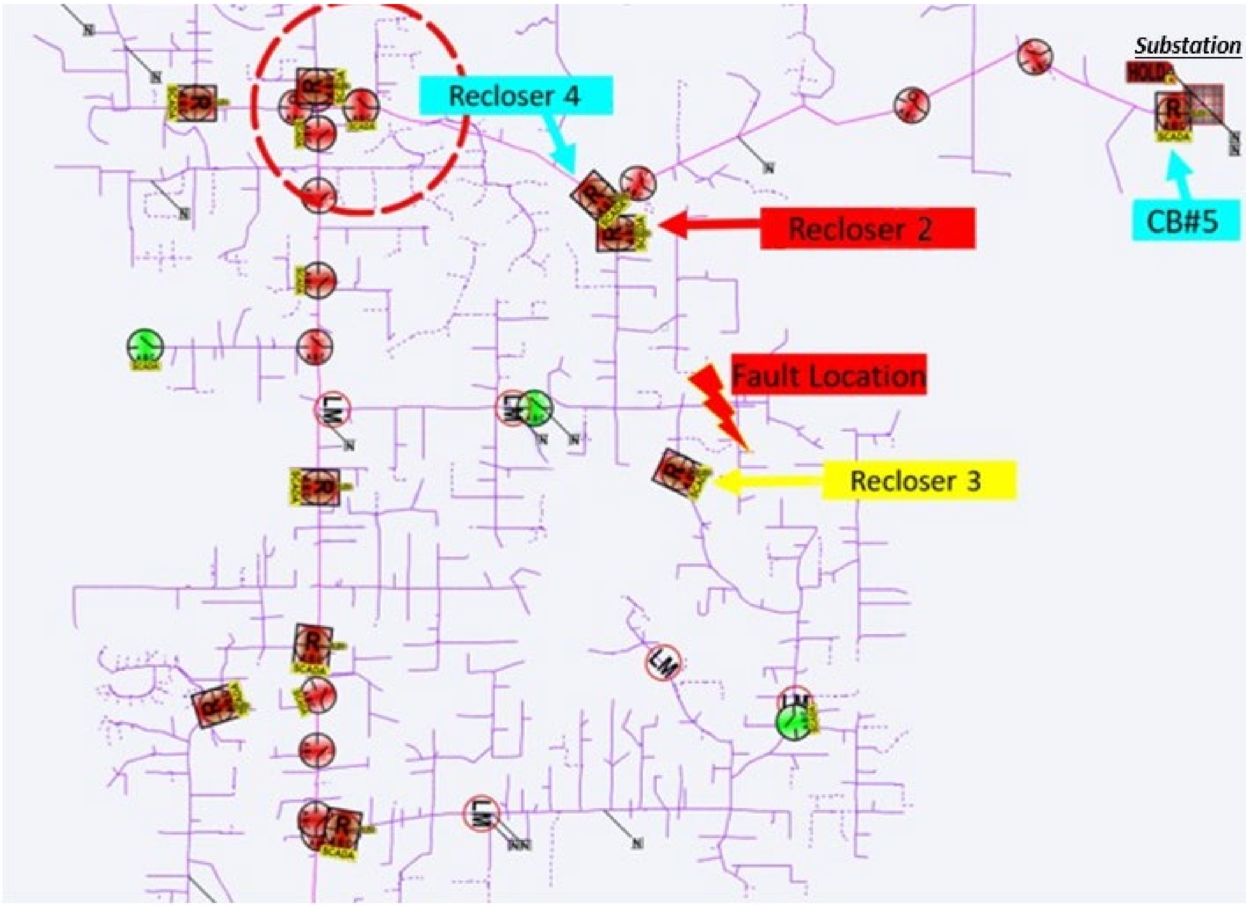


Fig. 38. Circuit 5 with the Reclosers 2, 3, 4 with Fault Location on June 25, 2021.

Phasor Measurement Units – Data Source Findings

1. Further investigation into the feasibility of the proposed techniques is required to demonstrate a solution that shows high enough precision and recall for the application scenario.
2. The requirements of the application (line break, for example), need to be translated into a requirement for precision and recall.
3. Further investigation into the feasibility of the proposed techniques is required for deployment in online scenarios. More work is needed to answer the question, “Can this technique detect line breaks early enough and can the algorithm be deployed at autonomous devices?”
4. More investigation is needed to simplify proposed algorithms without sacrificing performance so they can be easily deployable into field devices.
5. Data sources can be made consistent across the board, or data format for each type of device can be specified.

SECTION 4. STAKEHOLDER DEMONSTRATIONS

There were two demonstration iterations conducted during the project. The demonstrations aimed to obtain stakeholder feedback that can be incorporated into the focused patrol training, product enhancements and future research.

Demonstration Sessions

Demonstrations of the different use cases and scenarios were broken down into two logical groups and demonstrated in two different sessions.

Demonstration Session One Content

The following table summarizes the scenarios demonstrated in Iteration one.

Table 7 Session One Use Cases Demonstrated

Use Case	Scenario	Description	Duration (minutes)	Comments
Use Case 1 – Wire Down				
UC1 – Wires down (Trip and reclose)	UC1-1.1	***FLA and Meters*** Trip breaker, reclose successfully, raise Meter Low Voltage messages (phase A)	15	***(Switching plan #116216)*** ***FLA delay in starting – system wide config to allow for WFI information to be received***
	UC1-1.2	***FLA, WFI, Meters*** Trip breaker, successful reclose, Trigger WFI, Raise meter calls (Phase B)	10	***(Switching plan #116244)*** FLA fails on test system due to data quality in impedance model. Shows how WFIs can give operators location information
UC1 – Wire down (Trip and lockout)	UC1-2.1	***FLA, customer call*** Trip breaker and lockout, raise customer/damage call	10	***(Switching plan #116276)***
	UC1-2.2	***FLA, WFI*** Trip breaker and lockout, trigger WFI (phase A)	10	***(Switching plan #116245)***
	UC1-2.3	***FLA, WFI*** Trip breaker and lockout, trigger WFI (phase B)	10	***(Switching plan #116253)***
	UC1-2.4	***FLA, WFI***	20	***(Switching plan #116254)***

Use Case	Scenario	Description	Duration (minutes)	Comments
		Trip and lockout recloser, No WFI trigger		Locations from FLA do not identify beyond WFI that did not trigger Repeat scenario with no WFI configuration for FLA – shows all locations Re-enable WFI configuration for FLA
UC1 - Non-SCADA device Operates	UC-3.1	***FLA and Meters*** Raise Meter Low Voltage messages (phase A), raise customer damage calls	10	***(Switching Plan – 116236)*** Same as UC1.1 without recloser trip
	UC1-3.2	***FLA, WFI, Meters*** Trigger WFI, Raise meter calls (Phase B)	10	***(Switching Plan –116279)*** Same as UC1.2 without recloser trip *Note – Impedance model issues – FLA does not fire.
Use Case 6 – Underground Distribution				
UC6 – Trip and reclose	UC6-1.1	***FLA, FIs Power out***		
UC6 – Trip and lockout	UC6-2.1	***FLA and FIs*** Breaker trips and locks out. FLA activated showing potential locations. FI review and update as patrols investigate		***Switching plan (#116290)*** Added functionality to allow operators to tag FIs as operated

Demonstration Session Two Content

The following table summarizes the scenarios demonstrated in second demonstration session.

Table 8 Iteration Two Use Cases Demonstrated

Use Case	Scenario	Description	Duration (minutes)	Comments
Use case 1: Trip and reclose	(1) UC1.1.1 Substation example A (As-is)	Shows simulation of as-is scenario (RMO created, fault created and FLA potential locations shown)	10	***(Switching plan #223636)***
Use case 1: Trip and reclose	(1) UC1-1.1 Substation example A (Improved)	***FLA and Meters*** Trip breaker, reclose successfully, raise Meter Low Voltage messages (phase A)	10	***(Switching plan #223633)*** FLA delay in starting – system wide config to allow for WFI information to be received
Use case 1: Trip & Lockout	(4) UC2.2 (As-is)	***Recloser trip based on fault current***	10	***(Switching plan #223656)*** *WFIs disabled for this scenario and not considered by FLA*
Use case 1: Trip & Lockout	(4) UC2.2 (Improved)	***As above, with FLA and WFI*** FLAs reporting fault current detection	10	***(Switching plan #223639)*** WFIs re-enabled and used in FLA
Use case 1: Trip & Lockout	(4) UC2.2 (As-is)	***Repeat of previous scenario with WFI considered, but no WFIs enabled***	10	***(switching plan #223656)***
Use case 1: Trip & Lockout	(2) UC1-1.2 Substation example B - Phase B Fault (As-is)	***RMO***	10	***(Switching plan #223654)*** No FLA due to incorrect impedance model No further information on down-stream event
Use case 1: Trip and reclose Use case 1: Trip and reclose	(2) UC1-1.2 Substation example B - Phase B Fault (Improved)	***FLA, WFI, Meters*** Trip breaker, successful reclose, Trigger WFI, Raise meter calls (Phase B)	10	***(Switching plan #223637)*** No FLA due to incorrect impedance model WFIs available giving possible location information

Use Case	Scenario	Description	Duration (minutes)	Comments
Use case 1: Trip & Lockout	(5) UC1-2.3 - RINCON	***FLA, WFI on Phase B fault***	5	***(switching plan #223640)***
UC1 - Non-SCADA device Operates	(8) UC-3.1	***FLA and Meters*** Raise Meter Low Voltage messages (phase A), raise customer damage calls	5	***(Switching Plan – #223663)*** Same as UC1.1 without recloser trip
UC1 - Non-SCADA device Operates	(8) UC1-3.2	***FLA, WFI, Meters*** Trigger WFI, Raise meter calls (Phase B)	5	***(Switching Plan –223646)*** Same as UC1.2 without recloser trip *Note – Impedance model issues – FLA does not fire.

Demonstration Scripting and Development

The demonstration scenarios were scripted in the training simulator and are all available in the training simulator for use in training development. The training simulator utilizes the system switching plan list for easy access and playback of training scenarios. See ***Fig. 39.*** for an example of how the training simulator scripts appear in the switching list.

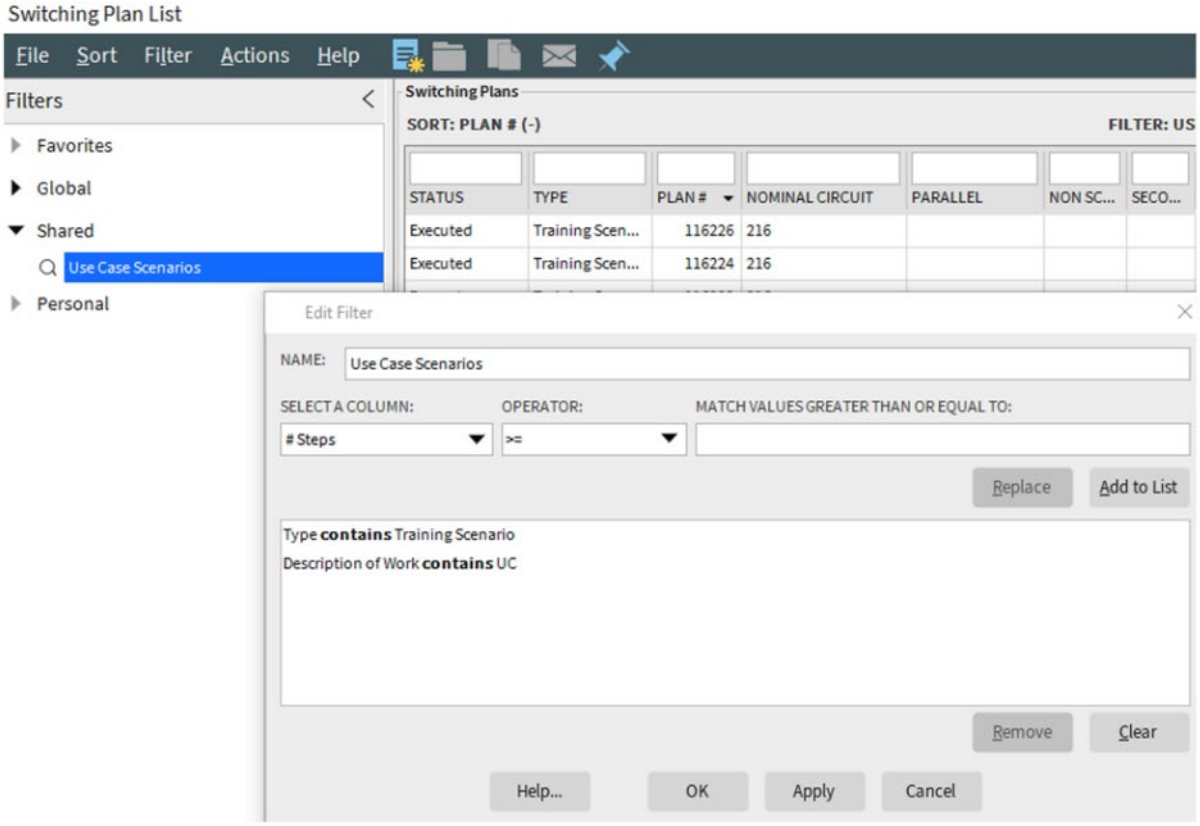


Fig. 39. Example Training Simulator Script

To play a scenario, the trainer must first identify an existing scenario and copy it. Once a training scenario has been executed, it cannot be executed again. The scenarios developed as part of this project can be treated as masters and used to create copies for execution in actual user training. New scenarios or training simulations can be created at any time given the appropriate system access. When using the training simulator functionality, the operator must be logged in as a “Trainer” user type. The operator is then given the choice of the type of switching plan to create. In this case, we want to select the training Scenario type as shown in ***Fig. 40.***

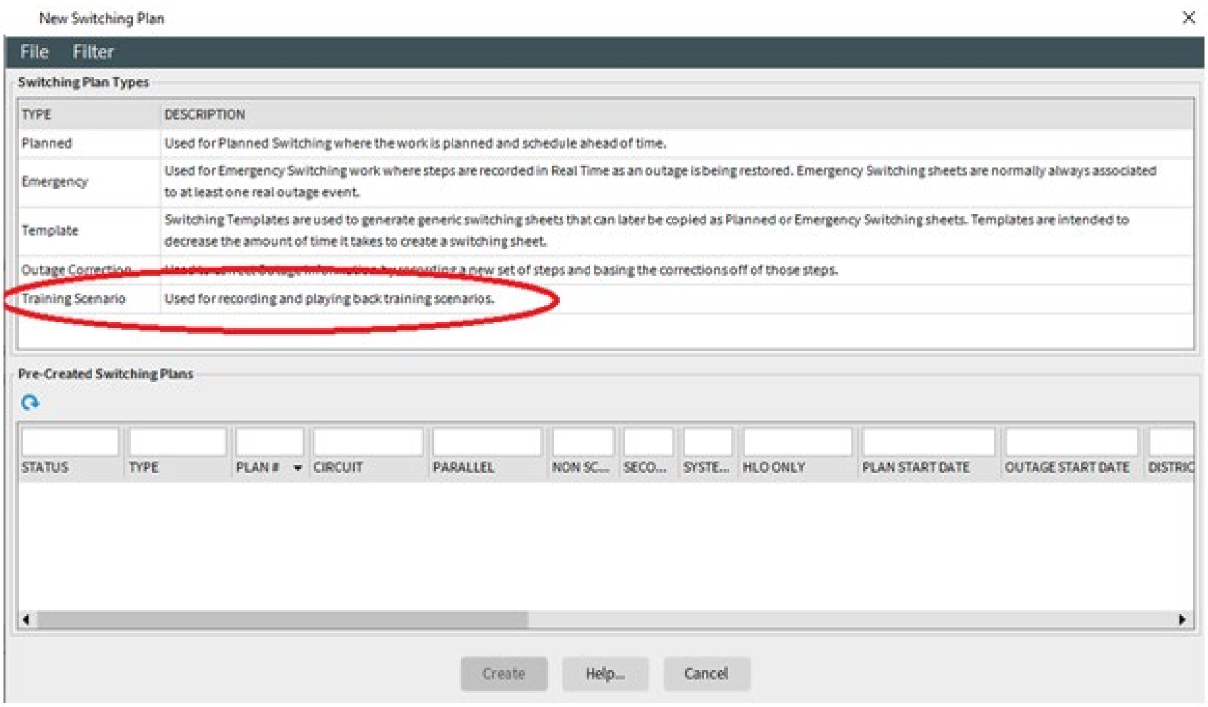


Fig. 40. Selecting Training Scenario Type

On selection, a new Training Scenario switching plan is created and automatically opens in "Record" mode. Recording can be stopped and started as required. It is recommended that activities performed are recorded and are done in "Study Mode" where possible.

To create a copy of an existing training scenario, one enters the plan number you want to copy from the table in the demo content's section, into the "Plan #" column in the bottom pane and press the refresh button. The plan you are searching for will appear in the lower pane. Select this plan and click "Training Scenario" in the top pane and click "Make a copy".

The Use Case scenarios created as part of this project are built up from the simulation of several different actions.

The following sections describe the steps for scripting different scenarios that are able to be performed using the training simulator based upon the use cases identified in this project.

Script #1 - Low Voltage Meter Calls

In real-time mode, perform the following steps (***See* Fig. 41**):

1. Ensure a training scenario switching plan is open and recording
2. Navigate to the transformer associated with meter points you wish to raise a message from
3. Open the Control tool for the transformer
4. Select the "Calls…" button and select "Submit call…"
5. Complete the details in the call entry form selecting Meter LV
6. Save the call

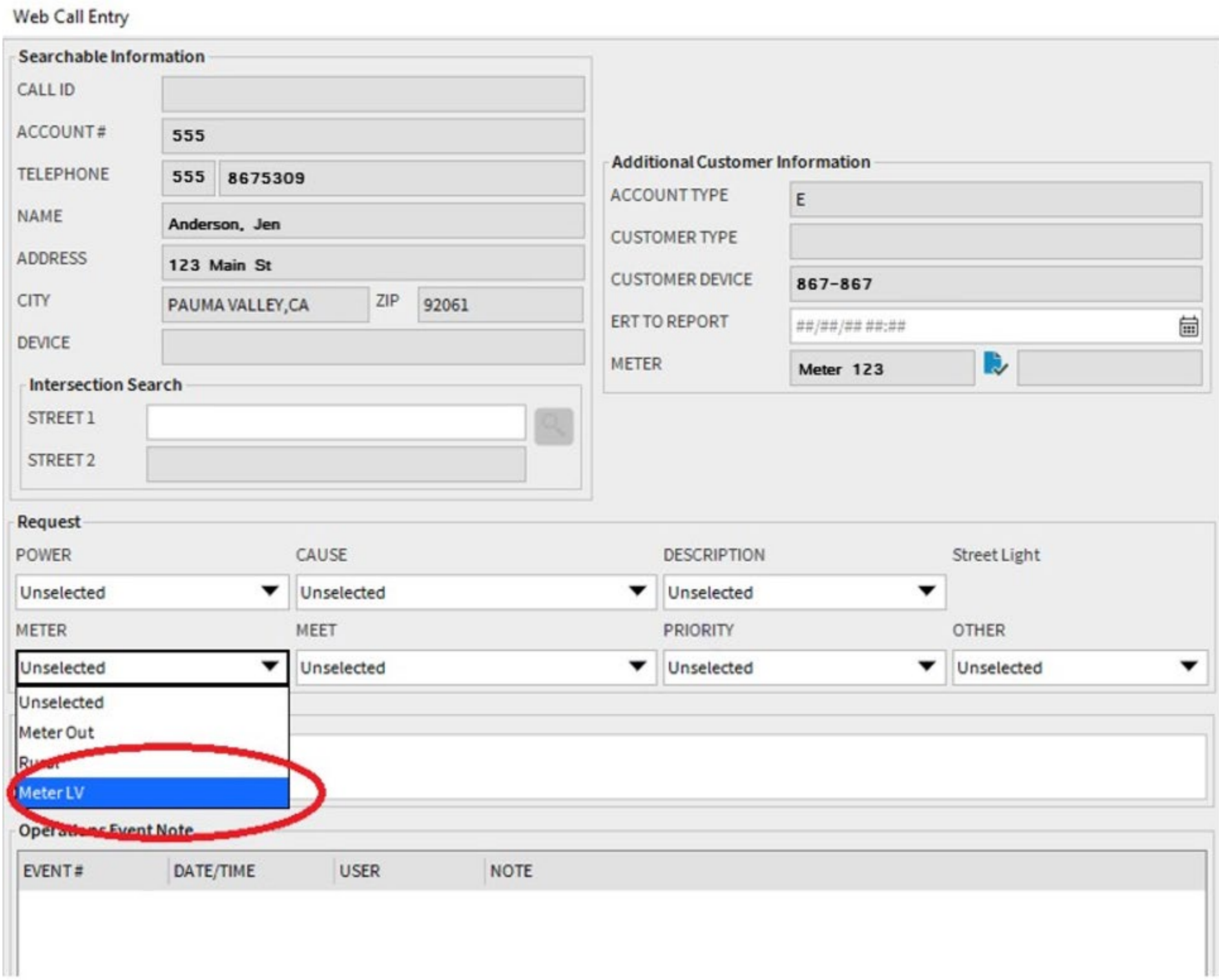


Fig. 41. Recording a Meter Low Voltage

The action will be recorded in the open training scenario switching plan.

Script #2: Wireless Fault Indicators (WFI)

In Study mode, ensure a training scenario switching plan is open and recording, and perform the following steps:

1. Navigate to a WFI and open the SCADA summary (right-click menu option from the NMS diagram)
2. Right-click on the point you wish to update (representing phase A, B or C)
3. Select “Simulate SCADA Entry…” and enter the value you require (1 – Fault Current detected, 0 – WFI normal state)

Script #3: Underground Fault Indicators

In study mode, perform the following steps:

1. Ensure a training plan scenario switching plan is open and recording
2. Navigate to FI
3. Open the Control Tool

4. Select the "Faults…" button and select appropriate action (Place FI, Remove FI)

Underground FIs are mechanical devices with no means of communication to central control systems. Only the visual inspection options available. The configuration was added to allow operators to mark as "Seen fault" and to "Remove fault". This can be simulated if required.

Script #4: Fault Injections

In study mode, perform the following steps:

1. Ensure a training scenario switching plan is open and recording
2. Note any fault current you require to simulate a fault (provided the impedance model is good, open the device details of a cable/line and examine the fault details tab. This will give you the fault values for the cable/line).
3. Inject the fault current in the appropriate attribute for a Line Recloser via the SCADA Summary
4. Update the TARGET_A SCADA point to "1" (this will put the point in an alarm state)

Script #5: Recloser Actions

In study mode, perform the following steps:

1. Select a Recloser and open the Control Tool
2. Select the Manual Operations button
3. Select the appropriate action (open, close)

Demonstrations Stakeholder Feedback

Because the demonstration was performed via web meeting and not in person, and that there was a relatively substantial number of participants in the demo, the opportunity for interactive feedback was limited. Subsequent follow-up with some key players indicated that the demonstration was well received and that they felt the new functionality that was demonstrated was practical and suitable to be used in training and production. However, there were some additional situations identified and issues commented on that would require additional investigation to ensure that there are no end cases that are not addressed.

Benefits Evaluation by Stakeholders

After the two demonstrations were complete and benefits review was completed. The analysis was designed to determine the impact of adding the new data sources to the system and gather information from the trainers on improvements and useability.

The stakeholder evaluation of each data source (rows) to the use cases (columns) is shown in **Table 9**. The value was rated as high, medium or low based upon the potential improvement in fault location or fault detection for a circuit that has significant patrol time associated with the restoration.

Table 9 Value of Data Source to Use Case Value

Data Source	UC1: Wire Down	UC2: Proactive Fault Detection	UC3: Foreign Object in line	UC4: Tree/Vegetation Contact	UC5: Overload Mitigation	UC6: Underground Distribution	UC7: Primary Voltage Customer Problem
Wireless Fault Indicators	High	Medium	Low	Low	Medium	Low	Low
Advanced Metering Infrastructure (AMI) Low Voltage Alarms	Medium	High	High	High	Low	Low	High
Weather Data	High	High	Low	Low	Low	Low	Low
Advanced Protective Relays	Low	Low	Low	Low	Low	Low	Low
Phasor Measurement Units (PMU)	High	High	Medium	Medium	Low	Low	Low

The usage of each data source (columns) for each fault scenario (rows) is shown in **Table 10**.

Table 10 Usage of each Data Source by Fault Scenario

Scenarios	Wireless Fault Indicators	Advanced Metering Infrastructure (AMI) Low Voltage Alarms	Weather Data	Advanced Protective Relays	Phasor Measurement Units (PMU)
SCADA detects	Yes	No	Yes	Unknown	Unknown
Manual protection device trips	Yes	Yes	Yes	Unknown	Unknown
No protection device trips	Yes	Yes	Yes	Unknown	Unknown

The impact of each type of new sensor on the benefits is shown in **Table 11**. The value was rated as high, medium or low based upon the potential improvement to the stated benefit based upon the sensor type.

Table 11 Sensor Value vs Benefit

Value of new sensors (High, Med, Low, Unknown)		Wireless Fault Indicators	Advanced Metering Infrastructure (AMI) Low Voltage Alarms	Weather Data	Advanced Protective Relays	Phasor Measurement Units (PMU)
Safety to SDG&E Personnel		High	Medium	High	Unknown	Medium
Safety for the Public		High	Medium	High	Unknown	High
Risk Reduction		High	Medium	High	Unknown	High
Reduced Cost, SAIDI		High	High	Medium	Unknown	Unknown
Improvement in Training Efficiency		High	High	High	Unknown	High

SECTION 5. PROJECT RESULTS AND VALUE PROPOSITION

Due to the intangible nature of this project (Staff Training), how fault location is conducted today (establish the baseline) was compared with how this new simulator will train SDG&E operators to conduct fault location in the future. Hence, the benefits that will be gained by the completion and implementation of the training stimulator will be the focus of the benefits estimate.

Currently, when an outage occurs, the DSO begins service restoration as soon as possible. Unless damage reports indicate where the cause is located, the DSO directly uses non-tripped fault indicator targets (when available) from the distribution line SCADA site(s) to determine if a line segment is free of faults. For all other cases, and during the non-fire season, where reclosing is permissible, the location of faults is sometimes confirmed through test closure of the feeder breaker or service restorer. The current process not only diminishes the resiliency of the system by weakening it each time a test closure into a fault is done, but is also not efficient, given that multiple field personnel must arrive on the scene before any testing occurs, thus prolonging the duration of the outage and having multiple electric troubleshooters drive from device to device. Test closures also degrade power quality for customers otherwise not involved with the outage.

This project has shown that with training, operators can have access to additional fault information to aid in the troubleshooting process and find the fault locations faster, requiring less patrolling. Due to the additional complexity of the data and the analysis required, having a realistic environment to train the operators is necessary to take full advantage of the new capabilities.

Safety to SDG&E's personnel

Because the Training Simulator will make the operators more efficient at determining fault location and directing field personnel to the correct location, it will inherently make the field personnel safer by reducing their driving exposure into more rural areas and sometimes dangerous weather conditions. Operations during hours of darkness are of special concern.

Safety to the public

The new Training Process and improved field equipment could allow the operators to find wire down events quicker, reducing public exposure to a potentially energized system.

Risk reduction

Since the fault location can be identified quicker, and the correct personnel deployed accurately and faster to that location, it will:

- Enable the organization to be better prepared for the future by offering more measures to mitigate/ decrease the risk of fires due to wire down or possibly other events, thus significantly reducing the overall risk that the company and its customers face as it relates to wildfire issues.
- Reducing the need for test closure could make us a more resilient utility by extending the life cycle of distribution equipment.

Metrics

Focused patrol training will allow for a quicker fault identification reducing the overall SAIDI and CAIDI.

Recent analysis showed that the troubleshooting time for a typical overhead outage that occurs on a distribution branch or circuit is approximately 84 minutes during working hours and approximately 111 minutes during non-working hours. This is the time measured from initial outage report to the time the outage cause was recorded by a troubleshooting crew. As described in *Table 1 Outage Restoration Steps*, that would be the elapsed time from T0 until T5. This excludes all outages that were local at a service transformer or secondary where there would be no patrolling time required.

The average time it took the troubleshooter to arrive and begin patrolling for these branch and circuit outages was 53 minutes during workhours and 73 minutes during non-workhours. As described in *Table 1* , that would be the elapsed time from T0 until T4. Thus, actual patrol time averaged 31 minutes during working hours and 48 minutes during non-working hours. Since the additional data identified in this study will allow the fault location to be identified to a relatively small segment of line, the patrolling should be reduced to the just the time required to get to the predicted area and confirm and/or patrol the smaller segment. It is reasonable to assume that the additional information available will reduce patrol time by at least 66% since it is typical for the fault to be downstream of one of a multiple number of branches and the savings would be based upon not having to patrol all the possible branches, assuming an average of 3 potential branches and the ETS crew only having to travel to the fault on one the three branches. This results in a Customer Minutes of Interruption savings of 20.5 minutes for working hour outages and 31.7 minutes for non-working hour outages.

The number of branch and circuit outages that occurred was 497 outages during working hours and 602 outages during non-working hours. Using these numbers, it is possible to estimate what would be the potential impact on system SAIDI, including Major Event Days (MED), and excluding transmission and planned outages). The calculation is summarized in the table below.

Table 12 Calculation of potential SAIDI Impact

Item	Value	Combined	Working Hours	Non-Working Hours	Units	Notes:
1	Outage Start to Cause Determined (T0-T5)	97.5	84.0	111.0	minutes	From SDG&E data
2	(Outage Start to On Scene) T0-T4	58	53.0	63.0	minutes	From SDG&E data
3	Patrol Time (T5-T4)	39.5	31.0	48.0	minutes	Item 1 - Item 2
4	Reduction in Patrol Time	66%	66%	66%	percentage	Estimated, based upon average of 3 possible branches to patrol
5	Improved Patrol Time	13.4	10.5	16.3	minutes	Item 1 - Item 2
6	CMI improvement for branch and circuit outages	26.07	20.5	31.7	minutes	Item 3 - Item 5
7	2018 Distribution SAIDI (including MED, excluding transmission and planned outages)	73.9			minutes	From page 8 of SDG&E Electric Reliability Report for 2018
8	2018 CAIDI (including MED)	112.3			minutes	
9	2018 SAIFI (including MED)	0.7			interruptions /cust	

Item	Value	Combined	Working Hours	Non-Working Hours	Units	Notes:
10	# of customers served	1458900			# Customers	From 2018 Annual Report
11	Total CMI	107768943			Customer Minutes	Item 7 * Item 10
12	Total # of circuit and branch outages (Jan-Sept 2018)	1099			Interruptions	From SDG&E data
13	Estimated Full year	1465			Interruptions	Convert 9 months to full year, assume uniform
14	# of customers in average circuit/branch outages (customers)	500			# Customers	Estimated average size of circuit and branch outages
15	CMI improved	19100620			Customer Minutes	Item 6*Item 13*Item 14
16	New Total CMI	88668323			Customer Minutes	
17	Estimated New Distribution SAIDI (including MED, excluding transmission and planned outages)	60.8			minutes	
18	SAIDI improvement	13.1			minutes	

Using the Interruption Cost Estimate Calculator at http://icecalculator.com/home, which was developed by Lawrence Berkeley National Laboratory funded by the Department of Energy Office of Electricity the impact of the reliability improvement is valued at approximately $30M per year as shown in **Fig. 42**:

Sector	# of Customers	Total Benefit (2015$)	Benefit per Customer (2015$)		Year	Without Improvement (Baseline)	With Improvement	Total Benefit
Residential	1293600	3,031,730.92	2.34		2021	307,744,078.88	277,484,190.42	30,259,888.46
Small C&I	125189	85,064,766.16	679.49		2022	313,898,960.46	283,033,874.23	30,865,086.23
Medium and Large C&I	25511	167,961,979.90	6,583.90		2023	320,176,939.67	288,694,551.71	31,482,387.96
All	**1444300**	**256,058,476.98**	**177.29**		2024	326,580,478.46	294,468,442.75	32,112,035.72
					2025	333,112,088.03	300,357,811.60	32,754,276.43
					2026	339,774,329.79	306,364,967.84	33,409,361.96
					2027	346,569,816.39	312,492,267.19	34,077,549.20
					2028	353,501,212.72	318,742,112.54	34,759,100.18
					2029	360,571,236.97	325,116,954.79	35,454,282.19
					2030	367,782,661.71	331,619,293.88	36,163,367.83

Sector	# of Customers	Total Benefit (2021$)	Benefit Per Customer (2021$)
Residential	1,293,600	$3,031,730.92	$2.34
Small C&I	125,189	$85,064,766.16	$679.49
Medium and Large C&I	25,511	$167,961,979.90	$6,583.90
All	**1,444,300**	**$256,058,476.98**	**$177.29**

Fig. 42. ICE Calculator Benefits Report

The impact of the reduced usage of test closure to identify fault location, and the resulting longer asset life is not calculated, but it is a noted benefit not quantized, but likely to result in additional savings.

SECTION 6. CONCLUSION FROM FINDINGS

This project demonstrated that some fault locations are difficult to predict based on an impedance only model used by ADMS today. The demonstration showed how better leveraged data from smart devices can complement existing ADMS fault location analysis and outage prediction models to improve overall customer service reliability and restoration costs.

The findings will help operations determine the most likely fault location more quickly and more accurately. Using additional data will also require new user interface (UI) configurations to prevent clutter when multiple alarms and events have been ingested. We found that the ADMS system will need to progressively display the most important prioritized options throughout an interactive process as information becomes available. This can be performed through a manual processes and diligent training in the control room, but the real value is in automation with real-time device streaming and all data available in a single view.

Utilities can identify cost effective projects to deploy additional sensors and related collection systems as needed.

SECTION 7. COMMERCIAL ADOPTION RECOMMENDATION AND TECHNOLOGY TRANSFER PLAN

Commercial Adoption Recommendations

It is recommended that the stakeholder groups within SDG&E who participated in this project pursue commercial adoption by organizing a commercialization team and appointing one key stakeholder group to lead the effort. The following near-term steps for commercial adoption were identified, based upon the results of this project:

- Develop a commercialization plan.
- Establish and maintain a permanent Training Simulator in a non-production environment and mirror the production system
- Add new data sources to the production system (weather data, AMI low voltage, Wireless Fault Indicators)
- Maintain a regular training program for the operators, reviewing scenarios analyzed during this project
- Continue to investigate new scenarios and new data sources (including Phasor Measurement Unit (PMU) data) in the Training Simulator as a continuous improvement practice

Technology Transfer Plan

Plan for disseminating the project results

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs internally within the utility, among fellow utilities in California, and more widely to the industry. To facilitate this knowledge sharing, this report will be posted on SDG&E's EPIC website.

Plan for transitioning to commercial use

There are several areas of investigation that appear promising for future commercialization. One of the main outcomes of the project was the applicability of new telemetry and other alternate datasets. The project was able to leverage data from PMU's, power quality meters and wireless fault indicators, alongside extended data from feeder relays (CEV, COMTRADE). These new data sources not only provided additional relevant facts on their own, but combined with each other in a machine learning environment, showed great potential to provide detailed insights and predictive power that can be leveraged across multiple advanced applications. Commercialization efforts will be undertaken to productize integrations to these new device types and automate the data collection and processing. Data science techniques will be extended and enhanced to capture the potential value of the new data sources, including rapid identification and classification of fault types, accelerated diagnosis and elimination of potential patrol locations, and longer-term evaluation of equipment condition and remaining useful life more fully.

The additional data sources should have a significant improvement on overall outage restoration times, especially as they are integrated into the operator training program. Use Cases 1, 3, 4, and 6 will particularly benefit from these areas. Steps for commercialization should include:

1. Identification of existing network devices where untapped data could be easily integrated
2. Enhancement of integration to these devices to include the new data source(s)
3. Map the new data source(s) to their corresponding device models in the distribution management system

4. Enable and train the new algorithms
5. Identify viable and efficient FLA algorithms tailored for the SDG&E system
6. Incorporate new insights into the operator training program
7. Identify future sites where similar devices may yield high value

Much of the information contained in this report should be useful to other utilities, as well as SDG&E, regardless of the technologies being employed for distribution management and fault detection and location. Although several of the improvements in patrol activities were specific to the methods and procedures used by SDG&E, the goal of outage response across utilities is universal: safely restore service as quickly as possible to as many customers as possible. The methods, technology, and training tools can be readily applied by utilities and their technology partners to evaluate and improve their own performance, even those who are not using the same ADMS.

SECTION 8. REFERENCES

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APPENDIX A—USE CASES

Use Case #1 Wire Down - Description

This Use Case details the process, or steps taken during an indication of an electric power issue identified from data gathered by the network with input from devices and customers impacted by power interruptions. The inputs to the Use Case are called Actors and the name, type and description of these Actors are described in the table below. The purpose of the Use Case is to simulate events triggered during scenarios where an overhead wire is down, and the event is visualized by a System operator. To build this Use Case, SDG&E provided a real-world situation experienced on the Network. The situation was discussed during workshops to gather information regarding the existing processes, sources of data and usage of existing information. The steps are captured below identifying the process performed. The goal of this Use Case is to assist the System operator to identify and isolate fault areas as quickly as possible. Once the hazard location is confirmed, conditions permitting, an optimal number of customers is restored through alternative power routing. During wildfire hazard conditions, minimal restoration may occur, and it is likely it will remain offline for the remaining duration of the event. Unknown damage could occur while the line is de-energized. If conditions are not extreme for wildfire, immediate restoration is more likely. After the fault is resolved, the System operator returns the system to normal conditions. This Use Case is intended to be used to simulate this process and document results.

Actors

The following table describes the Actors that are present throughout the Use Cases within this document. Actors include people, systems, devices and sensors in or affected by the functions.

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Advanced Distribution Management System (ADMS) - Outage Management System (OMS)	System	A subsystem that is responsible for managing outages including outage grouping of calls and AMI events, confirmation of outages and tracking of assigned crew resources and completion of outage restoration details.
Automated Meter Infrastructure (AMI)	System	The AMI system gathers, and stores information supplied by Smart Meters. It also can ping meters on request, to verify status.
Supervisory Control and Data Acquisition (SCADA)	Application	SCADA controlled/telemetered devices connected to control systems within the control room
System Operator	Person	Individual in charge of distribution operations and user of the Distribution Management System (DMS) and Outage Management System (OMS)

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Electric Trouble Shooter (ETS)	Person (crew of one qualified electrical worker)	Initial field staff sent to location to execute field operations, locate faults, and execute the operator's restoration plan
Phasor Measurement Unit (PMU)	Sensor	Device that gathers higher resolution line data
Power Quality (PQ) Meter	Sensor	Field equipment used by SDG&E
WFI	Sensor	Wireless Fault Indicator – sends status alarm using dedicated RF network to confirm if fault currents were witnessed from strategic points on the distribution network.
Advanced Protective Relay	Sensor/Actuator	Advanced Protective Relay, Fault Relay – microprocessor controlled protective device, most often working in conjunction with circuit breakers or switches.
Protective Device	Sensor/Actuator	Service restorers, feeder breakers, Individual device fuses, line fuses, vacuum/gas/air switch with SCADA
PMU Data Concentrator (PDC)	System	Device that collects PMU generated data
RTAC Real Time Automation Controller	System	Device that gathers line data, and can be programmed to act on the data as a function of pre-determined routines
OTV (Onramp Total View)	System	Fault indicator RF Network and data management system
Customer	Person	SDG&E electric customer
Caller	Person	Caller reporting an outage (customer and non-customer)

Triggers

This section details the triggers that can occur during the Wire Down scenarios. The triggers listed may occur in one or more scenarios and there is a "many to many" relationship between trigger events and Use Cases.

Triggering Event	***Primary Actor***	***Pre-Condition***	***Post-Condition***	***Additional Notes***
(Identify the name of the event that started the scenario)	*(Identify the actor whose point-of-view is primarily used to describe the steps)*	*(Identify any pre-conditions or actor states necessary for the scenario to start)*	*(Identify the post-conditions or significant results required to consider the scenario complete)*	*Elaborate on any additional description to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
Overcurrent condition detected.	Protective Device.	System operating normal.	Device opens to protect the network assets from the fault.	Every one of these devices will see the fault, but when properly coordinated, only one device will operate.
Power Out condition occurs at some meters.	AMI	System operating normal.	Loss of voltage detected, and message sent to AMI system. Meter powers down, sending a PON (Power Off Notification)	AMI sends event on loss of power and voltage alarm. Not all events will be received.
Under voltage condition occurs at some meters.	AMI	System operating normal.	Sustained under voltage detected and message sent to AMI system.	Sustained voltage duration and voltage limit set in firmware. Not currently sent to NMS.
Continuous monitoring.	PMU	PMU data captures 30 samples per second and sends to PDC in the substation. Then RTAC logic looks for differential (runs through 3 or 4 scenarios) and de-energizes the line.	Differential is detected and device operated for safety and to protect the system.	Information goes to Advanced SCADA. NMS doesn't receive the alarm information but receives the device operation.
Fault current detected.	WFI	System operating normal.	Over current (Fault level) followed by Sustained outage (loss of current) generates an alarm that is reported asynchronously to OTV.	SDG&E has approximately 2300 devices. WFI will only report a fault followed by loss of current after 3 minutes. Current parameter settings are the default settings. Refer to: WSO-

Triggering Event	*Primary Actor*	*Pre-Condition*	*Post-Condition*	*Additional Notes*
				11_IM_20171010 OnRamp ver.pdf Currently the data is not getting into NMS.
Fault current detected.	Advanced Protective Relay	System operating as normal.	Provides Information stored in a flat CEV file. Tree structure, need to "walk" down the tree to find. Files are automatically sent, and an email notification is sent to notify that a file has been added. Information is also stored in a database.	May not be available at the time of the fault. Could create an email box with an API to send a notification. No information is sent to NMS.
Continuous monitoring.	Power quality meters	System operating as normal.	Picks up harmonic information, high speed/resolution current/voltage sampling	

Wire Down

The following scenarios have been identified for the Use Case produced based on current state workshops completed:

- Trip/reclose – A SCADA monitored/controlled breaker or Recloser trips open and successfully recloses
- Trip/lockout – A SCADA monitored/controlled breaker or Recloser trips open and fails to successfully reclose after a pre-determined number of attempts. (Number of attempts may be ZERO)
- Non-SCADA device operates – no SCADA information available to detect the fault or to know real-time status closed/open, load, voltage, real/reactive power, etc.
- No SCADA trip, no fuse, protective relay, or circuit breaker operation – Issue on the line but no protection device operates (ex: conductor failure with insufficient fault current to operate fuse or other device)

The following sections details the scenarios above listing the sequence of events that takes place during the fault restoration process.

Trip & Successful Reclose

This scenario details the actions, inputs and received information in a scenario where a SCADA controlled/telemetered Protection device (namely an auto reclosing breaker or line recloser) opens and successfully recloses. In this scenario a wire is down, the device opened and reclosed, but the fault was not cleared and another protection device (i.e., a fuse) has operated clearing the fault downstream. Power is still provided upstream from the clearing protective device and the Recloser is closed and live.

Step #	***Actor***	***Description of the Step***	***Additional Notes***
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Protection device	Telemetered Protection device trips open on fault. NMS is aware via SCADA of the trip. No action at this point as the device has automatic reclosing enabled (configured in NMS as momentary capable)	Present practice in the HFTD fire tiers is to not attempt *automatic* reclosing year-round.
2	NMS	A timer is started to time the ARP within NMS	ARP – Auto reclose process – the process associated with equipment that can automatically reclose when tripped open
3	Protective device	ARP closes the device automatically. NMS is aware via SCADA, but no action taken	
4	NMS	The NMS timer expires, and device remains closed. ARP is complete.	Assuming a device downstream operates clearing the fault. If a line is down and no downstream devices operate, the recloser would not successfully reclose
5	NMS	NMS creates a Real Momentary Outage (RMO) recording the fact that an Auto-recloser operated and successfully reclosed.	
6	NMS	NMS creates one or more predicted fault locations and visually indicates potential locations on NMS model upon fault current measurement from the Advanced Protective Relay. NMS generates an additional alert for the operator from the FLA function.	
7	System Operator	The operator can display the possible locations based on distance to fault calculations, on the NMS network diagram and use this to start the patrols by foot, truck, or aircraft.	
In this scenario, to allow the reclose to be successful, it is assumed a downstream device has operated. This could result in operators receiving alerts related to low Ampere measurements at the feeder head due to lack of load further downstream. ***It is assumed that although the auto-recloser successfully closed, there is still a downstream outage. Steps to identify and resolve this outage are detailed in the following use cases. The type of downstream device will determine which use case applies (i.e., Telemetered/tele-controlled (SCADA) device, or manual only device)***			

Step #	*Actor*	*Description of the Step*	*Additional Notes*
8	System Operator	The operator takes the necessary actions to complete the RMO capturing relevant data for reporting and audit purposes	Typically, this will be complete on the resolution of the downstream outage. Until the downstream outage is identified, it is unknown if the recloser needs to be operated again to allow remedial work

Trip & Lockout

This scenario details the steps and triggers for an event where an auto-recloser trips, attempts to reclose one or more times, trips a final time and stops in an open and locked out state.

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Protection device	Telemetered Protection device trips open on fault. NMS is aware via SCADA of the trip. No action at this point as the device has ARP	
2	NMS	A timer is started to time the ARP within NMS	
3	Protective device/NMS	Before the ARP timer is complete, the protection device trips open again	
4	Protective device/NMS	AR Processing will attempt to reclose again (this can happen 1 or 2 times before a lockout state, or if it is a one-shot configuration no reclose happens)	
5	Protection device	Protection device trips open for the final time in the AR process. The breaker remains open and in a lockout state. AR processing is complete	
6	NMS	NMS creates a RDO associated with the protection device. Details of the operations are recorded including time of the first event. Scope of the outage is calculated based on the NMS model and a visual indication of the scope is present on the viewer. The event is listed in the Work Agenda	
As the recloser has locked out, the outage is confirmed, and the scope identified. From this point, the operators will carry out various activities to identify the fault area and take corrective action. The NMS system will receive several AMI messages where possible and potentially customer/non-customer calls with information related to the wire down. ***The identification actions are documented in the following use cases.***			

Non-SCADA Device Operates

This scenario describes the triggers and Systems available to the system operators for fault location detection (in this case a wire down) and the steps the system performs to aid the system operators in this analysis.

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Protection device	A manual (non-SCADA) protection device on the network operates due to the detection of a fault current	Operators/NMS are not aware of this situation currently
2	SCADA	Measurements at the feeder head may break limits due to loss of load downstream. Operators will be alerted to these breaches	This step may be present but will depend on the limit settings and amount of load lost. This information is unlikely but possible
3	System Operator	Acknowledges the fact that limits have been breached (if reported)	
4	WFIs	**Sustained** loss of current messages will be received from WFI devices in the field if they are present in the scope of the network. Alerts shown in WFI/On Ramp if currents drop below about five Amps.	
5	AMI	Messages from the AMI system are sent to the NMS system to make operators aware of the outage	
6	NMS	Several meter “no voltage” messages (PON’s) are received from the AMI system	Meter Power Off messages will be subject to filtering rules, for example: - Less than 10 minutes of outage start time - If more than one Power Off message exists and are within 90 seconds of each other (exception where only 1 meter is associated with a transformer) -
7	NMS	Based on the meter messages, a predicted outage (PDO) is created, and the predicted device is determined	
8	System Operator	Operator investigates the messages and the information in the PDO. Based on this information, they send a Trouble Shooter out to the device identified by NMS as the source	
9	Customer	A number of customers call in reporting loss of power or interruption to power	

Step #	*Actor*	*Description of the Step*	*Additional Notes*
10a	NMS	Assuming meter information has already been received, the calls will be associated with the existing PDO. Call areas may change the scope of the predicted outage.	
10b	NMS	If no meter information is received, the PDO will be created based on the call information	
11a	System Operator	Based on the calls reported the system operator sends out a Trouble Shooter (ETS) to the predicted fault location ***Note – if meter information is received then a trouble-shooter may already be enroute so no need for this step. Alternatively, if further information from callers is received (i.e., I can see a broken wire, etc.) a second trouble-shooter may be sent to the location of the reported wire down***	Location/wire down information may not be available at this point (i.e., if no one has called)
11b (Exception path)	System Operator	An emergency call may come in from the emergency services (or other callers) reporting sparking wire/dangerous situation.	
11c (Exception path)	System Operator	If step 11b exists, the Operator may operate the next upstream SCADA device to de-energize the section of network identified. This would potentially cause a greater outage scope, but it is necessary to make the area safe as soon as possible.	
12	Trouble Shooter	The trouble shooter(s) arrives on-site and reports information back to the system operator. (i.e., The state of the predicted device, the location of wire(s) down, etc.)	
13	System Operator	Based on information from the trouble shooter, the system operator will update the PDO to confirm the fault location or to re-direct the trouble shooter to find the downstream fault (in this case wire down).	If the fault is not found at this stage, the trouble shooter may have to “walk/drive the line” to find the potential fault area. This could be a time-consuming exercise depending on the information available, nature of terrain, etc.
14	System Operator	Once the fault area has been identified, the operator will dispatch a crew to the area to isolate the fault area and to re-energize sections of network where possible to re-connect customers. Crew dispatch, etc. will be managed via the NMS system. Visual representation of the	

Step #	***Actor***	***Description of the Step***	***Additional Notes***
		fault area can be shown on the diagram. In some cases, troubleshooters may isolate.	
15	System Operator/field crews	Once the fault is identified and supply is restored to as many customers as possible, the system operator will work with the available crews to repair the faulty section and restore the network to normal configuration.	
Alternative sources of information: To speed up the fault-finding process, the system operators have other sources of information at their disposal. Note, this information is not sent to the NMS system. This is a “go get” situation to potentially narrow the search for the Trouble Shooters. The alternative sources of information follow.			
16	System Operator	The system operator can ping meters on the line to help narrow down the fault area. This information can be used to estimate the type of fault and the phases affected.	
17	Callers	As the investigation continues, more calls can be received giving more details of the outage – i.e., potential location information based on observations from the public or emergency services	
18	System Operators	With information from these other sources, the system operators can perform Fault type analysis (phase to phase, phase to ground) to help determine fault type. This information may narrow down the search. For example, if it’s a phase-to-phase fault then it can’t be on a single-phase network area as found through the process of elimination.	Information for fault finding may involve downloading of information from relays at substations. This may involve sending technicians to these sites to download and send information via email or other means. Some information may also be automatically emailed to the Control room. This would require the system operators to be monitoring emails during a fault situation.

Breaker Does Not Trip and Fuse Does Not Operate

After review, it was determined that the scenario for this condition is the same as the "Non-SCADA Device Operates" scenario.

High Impedance faults are good examples of faults where protection devices do not operate. The fault current looks like an increase in load and is typically not high enough to cause these devices to operate. In these cases, the line would still be energized and will cause hazards. Examples of high impedance faults include:

- Wire down and resting on a building
- Wire down and resting on a road or the pavement
- Wire down on dry paving, rocks, or sand

Use Case #2 - Proactive Fault Detection Description

This Use Case details the process performed during an electric power issue on the grid and the steps taken to resolve the issue and/or complete the restoration during a power outage. The issue is analyzed by system operators using data gathered from the network and other communications such as customers reporting a power outage. The inputs to the Use Case are called Actors and the name, type and description of these Actors are described in the table below. To build this Use Case, SDG&E provided a real-world network issue experienced by system operators. The situation was discussed during workshops to gather information regarding the existing processes, sources of data and how the information is used by the system operators. The steps are captured below identifying the process performed to identify the issue, location and ultimately restore power. The Use Case details are designed to use as a step-by-step simulation guide to explore options and simulate a process assisting the System operators in identifying and isolating fault areas as quickly as possible.

The following notes were captured during the SDG&E Use Case Workshops:

- Instantaneous detection of failures
    - Example: A conductor experiences a break due to unknown physical stress (car-hit-pole, tree branch falling through the wire, gunshot damage, etc.). Many of these failures cannot be prevented, but the project will investigate the possibility of detecting this situation using high-speed sensors to de-energize the conductor prior to it striking the ground, causing an arc, and becoming a fire and/or public safety hazard.

- Prediction of near-term failures
    - Example: Utility infrastructure experiences wear and tear due to both normal operations and fault operations, requiring periodic inspection and maintenance. In many cases these points of failure, such as loose ties, broken crossarms, worn contacts, etc., are often not detected prior to causing a fault. The research project will investigate the possibility of detecting leading indicators of these types of failures so that the equipment may be safely repaired or replaced beforehand on a planned basis.

- Estimation of equipment loss of life
    - Example: Utility infrastructure weakens over time due to loading, weather, and other factors. Many factors such as corrosion due to coastal exposure, conductor annealing due to short-term high overloads, etc., may not be fully captured and modeled by asset management systems. The research project will investigate the use of operational data to enhance equipment aging and failure models to improve capital and maintenance spending with the goal of reducing overall equipment failure rates.

Actors

The following table describes the Actors that are present throughout the Use Case within this document. Actors include people, systems, devices, and sensors in or affected by the functions.

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Advanced Distribution Management System (ADMS)	System	A subsystem that is responsible for managing outages including outage grouping of calls and AMI events, confirmation of outages, and tracking of assigned crew resources and completion of outage restoration details.
Automated Meter Infrastructure (AMI)	System	The AMI system gathers, and stores information supplied by Smart Meters. It also can ping meters on request, to verify status.
Supervisory Control and Data Acquisition (SCADA)	Application	SCADA controlled/telemetered devices connected to control systems within the control room
System Operator	Person	Individual in charge of distribution operations and user of the ADMS, AMI, and SCADA.
Line Crew	Person(s)	Person working alone or with other personnel to operate the distribution system under the direction of a system operator
Equipment Inspector	Person	Person working alone or with other personnel to inspect distribution and/or substation equipment for maintenance, repair, and/or replacement
Phasor Measurement Unit (PMU)	Sensor	Device that gathers higher resolution line data
Fault Current Indictors (FCI)	Sensor	Devices that sense and report when a preset level of fault current occurs at a point on the system
Power Quality (PQ) Meter	Sensor	Power Quality Meter – high resolution waveform data
WFI	Sensor	Wireless Fault Indicator – sends status alarm using dedicated RF network to confirm if fault currents were witnessed from strategic points on the distribution network.

Actor Name	***Actor Type (person, device, system etc.)***	***Actor Description***
Advanced Protective Relay	Sensor/Actuator	Advanced Protective Relay, Fault Relay – microprocessor controlled protective device control, most often working in conjunction with circuit breakers or switches.
PMU Data Concentrator (PDC)	System	System that collects PMU generated data.
RTAC Real Time Automation Controller	System	Device that gathers line data, and can be programmed to act on the data as a function of pre-determined routines
OTV (Onramp Total View)	System	Fault indicator data management system.
Distribution Planner	Person	Individual in charge of capacity planning for the distribution system.
Maintenance Engineer	Person	Individual in charge of planning maintenance and capital replacement for the distribution system.
Enterprise Asset Management System (EAM)	Application	A combination of systems, services and software to control assets and equipment.

Triggers

This scenario is not a current part of operations and is a part of maintenance and planning.

Triggering Event	***Primary Actor***	***Pre-Condition***	***Post-Condition***	***Additional Notes***
(Identify the name of the event that start the scenario)	*(Identify the actor whose point-of-view is primarily used to describe the steps)*	*(Identify any pre-conditions or actor states necessary for the scenario to start)*	*(Identify the post-conditions or significant results required to consider the scenario complete)*	*Elaborate on any additional description to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
Fault	Service restorers, feeder breakers, Individual device fuses, line fuses, line switches (SCADA only)	Overcurrent occurs	device operates to clear the fault	Every one of these devices will see the fault, but when properly coordinated, only one device will operate
Fault	AMI	May see a partial dip or all loss of power. Will see the effect of the fault.	Will see the effect of the operation.	AMI sends event on loss of power and voltage alarm. Not all events will be

Triggering Event	***Primary Actor***	***Pre-Condition***	***Post-Condition***	***Additional Notes***
				received. All voltage and power alarms are received near real time (within a minute).
Fault	PMU	PMU data captures 30 samples per second and sends to distribution substation. Then RTAC logic looks for differential (runs through 3 or 4 scenarios) and de-energized the line.	Line is de-energized.	Information goes to Advanced SCADA. NMS doesn't receive the alarm information but receives the device operation.
Fault	WFI	Sustained outage following a fault, or a sustained loss of current is reported asynchronously to OTV. The data then goes from OTV to the message bus. Currently the data is not getting into NMS.		SDGE has approximately 2300 devices. WFI will only report a loss of current after 3 minutes. Current parameter settings are the default settings.
Fault	Advanced Protective Relay Fault Records	Information stored in a flat CEV file. Tree structure, need to walk down the tree to find. Files are automatically sent, and an email notification is sent to notify that a file has been sent. Information is also stored in a database.		May not be available at the time of the fault. Could create an email box with an API to send a notification.
Fault	Power quality monitors	Picks up harmonic information, high speed current/voltage sampling		

Triggering Event	***Primary Actor***	***Pre-Condition***	***Post-Condition***	***Additional Notes***
Data Threshold Exceeded	RF Early Fault Detection System	Analyze RF signature of downstream equipment as indicators for potential faults.		
Operations	NMS	Equipment information. Ex: number of operations		Coordination device operations with system conditions (line regulators)
Construction	GIS/NMS	Date of installation.		
Inspections	GIS/NMS	Field inspections		
Study	NMS	Use existing NMS tables to gather information on historical overloads/violations that may be a factor for degradation		
Study	NMS	Coordinate device operations with weather data		Flat files are being sent to NMS
Study	Maintenance/Planning	Is it possible to use/access the information? What information is available that could be used? Discuss to see how NMS data is used historically.		

Step by step analysis

Scenario 1: Instantaneous detection of failure

Example: A conductor experiences a break due to unforeseen physical stress (car-hit-pole, tree branch falling through the wire, etc.). Many of these failures cannot be prevented, but the project will investigate the possibility of detecting this situation using high-speed sensors to de-energize the conductor prior to it striking the ground, causing an arc and becoming a fire and/or public safety hazard.

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Conductor breaks	Conductor breaks due to physical stress or unknown defect	
2	Phasor Measurement Unit (PMU)	Phasor Measurement Unit continuously measures voltage and current magnitudes and phase angles	Sends output to the RTAC
3	Power Quality Meter (PQM)	Power Quality Monitor continuously measures waveforms and harmonic content of current and voltage waveforms	Sends output to the RTAC
4	RTAC Real Time Automation Controller	Based on data from PMUs and/or PQMs, RTAC (potentially) detects an instantaneous change in the current, voltage, and/or harmonic measurements to reliably indicate that a component has failed downstream	If this can be detected and analyzed quickly enough, a trip command to open the breaker can be sent directly to the Advanced Protective Relay
5	Advanced Protective Relay	Instantaneously trips and remains open	If this can be detected and acted upon quickly enough, no fault will occur

Scenario 2: Prediction of near-term failures

Example: Utility infrastructure experiences wear and tear due to both normal operations and fault operations, generally requiring periodic inspection and maintenance. In some cases, these points of failure, such as loose ties, broken crossarms, worn contacts, etc. are not detected prior to them causing a fault. The project will investigate the possibility of detecting leading indicators of these types of failures so that the equipment may be safely repaired or replaced beforehand.

Step #	***Actor***	***Description of the Step***	***Additional Notes***
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Scheduled line inspector	This scenario is not a current part of operations, is a part of maintenance and planning.	Usually driven by GO 165 requirements
2	Line crew	Makes note that a device is not operating properly as part of routine operations (sticky/mis-adjusted switch, etc.), running hot per recent IR check.	Added to NMS as an operational note
3	Equipment inspector	Reports typical or atypical wear and tear on a piece of equipment	Added as a condition assessment in the EAM
4	SCADA	Reports routine measurements from various sensors that are temporarily out of normal tolerances but do not cause a fault condition	Sent to historian but generally not acted upon immediately
5	PQ Meter	Continuous reporting of power quality data	
6	PMU	Continuous reporting of phasor measurement data	
7	Advanced Protective Relay	Generation of fault record after each fault event	Recorded in Advanced Protective Relay fault record system, including oscillography
8	RTAC	Collection of PQ and PMU data	Collects and transmits PQ/PMU data
9	WFI	Indication of faults beyond a point in the network	Also, a source of low-resolution load data reported synchronously
10	NMS and Analytics	Collection of loading, power flow, and fault data from any/all the above sources; could be able to record which devices/conductors were put under stress due to experiencing through-faults (even if they did not fail immediately)	Applying machine learning or other analytics, it may be possible to detect aberrant behavior of devices that could indicate a failure soon

Scenario 3: Estimation of equipment loss of life

Example: Utility infrastructure weakens over time due to loading, weather, and other factors. Many such factors such as corrosion due to coastal exposure, conductor annealing due to short-term high overloads, etc., may not be fully captured and modeled by asset management systems. The project will investigate the use of operational data to enhance equipment aging and failure models to improve capital and maintenance spending with the goal of reducing overall equipment failure rates and unplanned service interruptions.

Step #	***Actor***	***Description of the Step***	***Additional Notes***
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Scheduled line inspectors	This scenario is not a current part of operations, is a part of maintenance and planning.	Usually in compliance with GO 165
2	Line crew	Makes note that a device is not operating properly as part of routine operations (sticky/mis-adjusted switch, etc.)	Added to NMS as an operational note
3	Equipment inspector	Reports typical or atypical wear and tear on a piece of equipment	Added as a condition assessment in the EAM
4	SCADA	Reports routine measurements from various sensors that are temporarily out of normal tolerances but do not cause a fault condition	Sent to historian but generally not acted upon immediately
5	PQ Meter	Continuous reporting of power quality data	
6	PMU	Continuous reporting of phasor measurement data	
7	Advanced Protective Relay	Generation of fault record after each fault event	Recorded in Advanced Protective Relay fault record system, including oscillography
8	RTAC	Collection of PQ and PMU data	Collects and transmits PQ/PMU data
9	WFI	Indication of faults beyond a point in the network	Low resolution load data available synchronously
10	NMS	Power flow calculations	
11	Maintenance Engineer	Analyzes available data from condition-based maintenance and other sources and systems.	

Use Case #3 Foreign Object Faults Description

This Use Case details the process performed during an electric power issue on the grid and the steps taken to resolve the issue and/or complete the restoration during a power outage. The issue is analyzed by system operators using data gathered from the network and other communications such as customers reporting a power outage. The inputs to the Use Case are called Actors and the name, type and description of these Actors are described in the table below. To build this Use Case, SDG&E provided a real-world network issue experienced by system operators. The situation was discussed during workshops to gather information regarding the existing processes, sources of data and how the information is used by the system operators. The steps are captured below identify the process performed to identify the issue, location, and then to restore power. The Use Case details are designed to use as a step-by-step simulation guide to explore options and simulate a process assisting the System operators in identifying and isolating faulted areas as quickly as possible.

This Use Case details the scenario where Foreign Objects are found tangled in overhead lines. This stems from the frequency at which so-called Mylar (celebratory) balloons are left untethered and float into the O/H lines and become tangled. The metallic "foil" coating and helium gas of these balloons conducts electricity and can cause electrical outages when they encounter the O/H network. There is also a real fire risk as contact from these objects can cause sparking. There have also been incidents of explosions when contact is made near an O/H transformer. In 2017, there were over 100 incidents of this type of contact.

Actors

The following table describes the Actors that are present throughout the Use Case within this document. Actors include people, systems, devices, and sensors in or affected by the functions.

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Advanced Distribution Management System (ADMS) - Outage Management System (OMS)	Systems	A subsystem that is responsible for managing outages including outage grouping of calls and AMI events, confirmation of outages and tracking of assigned crew resources and completion of outage restoration details.
Automated Meter Infrastructure (AMI)	System	The AMI system gathers, and stores information supplied by Smart Meters. It also can ping meters on request, to verify status.
Supervisor Control and Data Acquisition (SCADA)	Application	SCADA controlled/telemetered devices connected to control systems within the control room
System Operator	Person	Individual in charge of distribution operations and user of the Distribution Management System (DMS) and Outage Management System (OMS)

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Phasor Measurement Unit (PMU)	Sensor	Device that gathers higher resolution line data
Fault Indictor	Sensor	Provides local indication when fault above a given threshold occurs at a strategic point on the system
WFI	Sensor	Wireless Fault Indicator – sends status alarm using dedicated RF network to confirm if fault currents were witnessed from strategic points on the distribution network.
OTV (Onramp Total View)	System	Fault indicator RF Network and data management system
Advanced Protective Relay	Sensor/Actuator	Advanced Protective Relay, Fault Relay – microprocessor controlled protective device control, most often working in conjunction with circuit breakers or switches.
Protective Device.	Sensor/Actuator	Service restorers, feeder breakers, Individual device fuses, line fuses, vacuum/gas/air switch (SCADA only)
PMU Data Concentrator (PDC)	System	System that collects PMU generated data

Triggers

This section details the triggers that can occur during the Foreign Object in Lines scenarios. The triggers listed may occur in one or more scenarios. There are many relationships between trigger events and user cases.

Triggering Event	*Primary Actor*	*Pre-Condition*	*Post-Condition*	*Additional Notes*
(Identify the name of the event that started the scenario)	*(Identify the actor whose point-of-view is primarily used to describe the steps)*	*(Identify any pre-conditions or actor states necessary for the scenario to start)*	*(Identify the post-conditions or significant results required to consider the scenario complete)*	*Elaborate on any additional description to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
Overcurrent condition detected.	Protective Device.	System operating normal.	Device opens to protect the network assets from the fault.	Every one of these devices will see the fault, but when properly coordinated, only one device will operate

Triggering Event	***Primary Actor***	***Pre-Condition***	***Post-Condition***	***Additional Notes***
Power Out condition occurs at some meters.	AMI	System operating normal.	Loss of voltage detected, and message sent to AMI system. Meter powers down.	AMI sends event on loss of power and voltage alarm. Not all events will be received.
Under voltage condition occurs at some meters.	AMI	System operating normal.	Sustained under voltage detected and message sent to AMI system.	Sustained voltage duration and voltage limit set in firmware. Not currently sent to NMS.
Continuous monitoring.	PMU	PMU data captures 30 samples per second and sends to PDC in the substation. Then RTAC logic looks for differential (runs through 3 or 4 scenarios) and de-energizes the line.	Differential is detected and device operated to protect the system.	Information goes to Advanced SCADA. NMS doesn't receive the alarm information but receives the device operation.
Fault current detected.	WFI	System operating normal.	Over current (Fault level) followed by Sustained outage generates an alarm that is reported asynchronously to OTV.	SDG&E has approximately 2300 devices. WFI will only report a loss of current after 3 minutes. Current parameter settings are the default settings Currently the data is not getting into NMS.
Fault current detected.	Advanced Protective Relay	System operating as normal.	Information stored in a flat CEV file. Tree structure, need to walk down the tree to find. Files are automatically sent, and an email notification is sent to notify that a file has been added. Information is also stored in a database.	May not be available at the time of the fault. Could create an email box with an API to send a notification. No information is sent to NMS.

Triggering Event	*Primary Actor*	*Pre-Condition*	*Post-Condition*	*Additional Notes*
Continuous monitoring.	Power quality meters	System operating as normal.	Picks up harmonic information, high speed current and voltage waveform data.	

Foreign Object in Lines

The following scenarios have been identified for the Use Case, derived from workshops completed based on existing conditions:

- Trip/reclose – A SCADA monitored/controlled Recloser trips open and successfully recloses
- Trip/lockout – A SCADA monitored/controlled Recloser trips open and fails to successfully reclose after a pre-determined number of attempts.
- Non-SCADA device operates – no SCADA information available to detect the fault
- No SCADA trip, no fuse operation – Issue on the line, but no protection device operates

The following sections detail the scenarios above listing the sequence of events that takes place during the service restoration process.

Trip and Successful Reclose

This scenario details the actions, inputs and received information in a scenario where a SCADA controlled/telemetered protection device (namely an auto reclosing breaker) opens and successfully recloses.

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Foreign Object	A foreign object (e.g., Foil Balloon/tree/animal) hits a line and causes fault current	This event is unknown to the Operator currently
2	Recloser/protection device	The SCADA Recloser detects the fault current and trips open	
3	NMS	A timer is started to time the ARP process within NMS	Recloser is configured as a momentary capable device

Step #	***Actor***	***Description of the Step***	***Additional Notes***
			ARP – Auto reclose process – the process associated with equipment that can automatically reclose when tripped open
4	Recloser/protection device	The recloser closes automatically. NMS is aware via SCADA, but no action taken	
5	NMS	The NMS timer expires, and the device remains closed. ARP is complete	
6	NMS	NMS creates a Real Momentary Outage (RMO) recording the fact that an Auto-recloser operated and successfully reclosed.	
7	NMS	NMS creates one or more predicted fault locations and visually indicates potential locations on NMS model upon fault current measurement from the Advanced Protective Relay. NMS generates an additional alert for the operator from the FLA function.	
8	System Operator	The operator can display the possible locations based on "distance to fault" calculations, on the NMS network diagram and use this to start patrols.	
9	NMS	Power quality events may be raised by customers. Depending on the NMS configuration and the time of the call, they may be associated with the RMO or handled via a new event	
In this scenario, it is assumed the foreign object has cleared from the line and the fault condition is gone. At this point, the system operator is unaware of what caused the fault (i.e., he/she does not know it's a balloon in the line and has now cleared. Should there be a further downstream outage, the operator will be made aware via meters or customer calls. Refer to Use Case 1 – Wire down for further information			

Trip & Lockout

This scenario details the steps and triggers for an event where an auto-recloser trips, attempts to reclose one or more times, trips a final time, and stops in an open and locked out state.

Step #	Actor	Description of the Step	Additional Notes
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Foreign Object	A foreign object (e.g., "Mylar" Balloon) hits a line and causes a fault current	
2	Recloser/protection device	The SCADA Recloser detects the fault current and trips open	
3	SCADA Fault Detector	The SCADA Fault Indicator reports a fault, and the fault is shown in NMS. The NMS shows how many phases were faulted and if the fault was phase to ground.	
4	NMS	A timer is started to time the ARP process within NMS	Recloser is configured as a momentary capable device
5	Protective device/NMS	AR Processing will attempt to reclose again (this usually happens 2 to 3 times before a lockout state)	
6	Protection device	Protection device trips open for the final time in the AR process. The breaker remains open and in a lockout state. AR processing is complete	
7	NMS	NMS creates an RDO (Remote Device Operated) associated with the protection device. Details of the operations are recorded including time of the first event. Scope of the outage is calculated based on the NMS model and a visual indication of the scope is present on the viewer. The event is listed in the Work Agenda	
As the recloser has locked out, the outage is confirmed, and scope identified. From this point, the operators will carry out various activities to identify the fault area and take corrective action. The NMS system will receive several AMI and WFI messages where possible and potentially customer/non-customer calls with information related to the wire down. ***The identification actions are documented in the following use cases.***			

Non-SCADA Device Operates

This scenario describes the triggers and Systems available to the system operators for fault location detection (in this case foreign object in line) and the steps performed to aid the system operators in this analysis.

Step #	Actor	Description of the Step	Additional Notes
#	*What actor, either primary or secondary, is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc., may also be noted in this column.*
1	Protection device	A manual (non-SCADA) protection device on the network operates due to the detection of fault current	Operators/NMS are not aware of this situation currently
2	SCADA	Measurements at the feeder head may break limits due to loss of load downstream. Operators will be alerted to these breaches	This step may be present but will depend on the limit settings and amount of load lost. This information is unlikely but possible
3	System Operator	Acknowledges the fact that limits have been breached (if reported)	
4	WFIs	Sustained "no current" messages will be received from WFI devices in the field if they are present in the scope of the network. Alerts will be shown in NMS. Current must fall below a threshold of about five Amps.	
5	AMI	Messages from the AMI system are sent to the NMS system to make operators aware of the outage	
6	NMS	Several meter no voltage messages are received from the AMI system	Meter Power Off messages will be subject to filtering rules, for example: - Less than 10 minutes of outage start time - If more than one Power Off message exists and are within 90 seconds of each other (exception

Step #	***Actor***	***Description of the Step***	***Additional Notes***
			where only 1 meter is associated with a transformer)
7	NMS	The meter information is associated with the RDO event	
8	System Operator	Operator investigates the messages and the information in the RDO.	
9	System Operator	The operator dispatches a trouble shooter to the Protection device to confirm the status open/closed and patrol the lines downstream to try and determine the fault location	
10	System Operator	The operator continues the investigation using information obtained from other systems. - CEV flat files from Advanced Protective Relays and notification of file availability is sent to operators - The WFI/OTV system can be interrogated to help narrow down the fault location - Fault analysis is conducted. The type of fault may also reduce the volume of fault location predictions. - FLA activation may occur displaying predicted locations based on distance to fault information and the network model information (NMS)	
11	Customer	Several customers call in reporting loss of power or partial power.	
12	NMS	All relevant calls from customers within the outage scope are automatically associated with the RDO	
13a	System Operator	As the investigation continues and further calls are logged, the operator may re-direct the trouble shooter to the most likely location	
13b (exception path)	System Operator	An emergency call may come in from emergency services (or other callers) reporting sparking wire/dangerous situation.	

Step #	***Actor***	***Description of the Step***	***Additional Notes***
13c (exception path)	System Operator	If step 13b exists, the Operator may operate the next upstream SCADA device to de-energize the section of network identified. This would potentially cause a greater outage scope but is necessary to remove the hazard safely, and quickly.	
14	Trouble Shooter	The trouble shooter(s) arrives on-site and reports information back to the system operator. (i.e., location details and fault cause)	
15	System Operator	Once the fault area has been identified, the operator will dispatch a crew to the area to isolate the fault area and to re-energize sections of the network where it is possible to restore customers. Crew dispatch will be managed via the NMS system. Visual representation of the faut area can be shown on the diagram.	
16	System Operator/field crews	Once the fault is identified and supply is restored to as many customers as possible, the system operator will work with the available crews to repair the faulted section and restore the network to normal configuration	
Alternative sources of information: To speed up the fault-finding process, the system operators have other sources of information at their disposal. Note, this information is not sent to the NMS system. This is a “go get” situation to potentially narrow the search for the Trouble Shooters. The alternative sources of information follow.			

Breaker Does Not Trip and Fuse Does Not Operate

This scenario details steps taken when a power quality issue occurs or there is a visual reported network issue that does not result in a power outage and protective devices have not operated.

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary, is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc., may also be noted in this column.*
1	N/A	A celebratory balloon floats into the overhead network bridging live phases (or phase to grounded hardware) and causing sparking.	Balloon coating (metalized) and helium is highly conductive
2	N/A	No protection device activates and no breaker trips and the supply is not compromised. No fault current is detected.	
3	WFI	Sustained "no current" messages will be received from WFI devices in the field if they are present in the scope of the network. Alerts will be shown in NMS	
4	Caller	A member of the public (first responder or a customer) calls in detailing sparking coming from an overhead line giving the location of the sparking	
5	Customer Service Rep.	The call taker receiving the call, logs the information in the web Call Entry system	
6	NMS	The NMS system creates a "NO" (No Outage) event based on the call information. The network model is updated with the information from the call	
7	System Operator	The system operator dispatches a Trouble shooter to the location as described in the call	
8a	Trouble Shooter	The trouble shooter reports no foreign object in line and all lines energized and operating as expected. Troubleshooter MAY find evidence of balloon or other remnants on the ground.	

Step #	Actor	Description of the Step	Additional Notes
	System Operator	Taking advice from the trouble shooter, the operator closes the incident with no further action	
8b	Trouble Shooter	The Trouble Shooter reports a foreign object in the line and confirms a dangerous condition with sparking.	
	System Operator	The operator updates the event with information from the Trouble Shooter	
	System Operator	Based on the information supplied, the operator plans activities to isolate the area of network. Crews are dispatched to isolate and to resolve the issue.	
	System Operator	These are managed via the PSO event to calculate and record outage information, resolution information and any follow-up work required.	
	System Operator	On completion of the work, the operator instructs the field crews to restore the network to normal condition.	
Due to the nature of the foreign object, in this case a celebratory balloon, the situation can change if the object moves. This could cause further automatic operations. For example, a phase-to-phase fault, should the object come into contact with 2 wires. The outcome of such events could cause protection devices to operate and de-energize a section of the network. The use case for this is covered previously depending on the device that operates (i.e., SCADA or non-SCADA)			

Use Case #4 Tree Vegetation Contact Description

This Use Case details the process, or steps taken during an indication of an electric power issue identified from data gathered from the network input from customers impacted from power interruptions. The inputs to the Use Case are called Actors and the name, type and description of these Actors are described in the table below. The purpose of the Use Case is to simulate events triggered during scenarios where an overhead wire is down, and the event is visualized by a System operator. To build this Use Case, SDG&E provided a real-world situation experienced on the network. The situations were discussed during workshops held to gather information regarding the existing processes, sources of data and usage of existing information. The steps captured below identify the process performed. The goal of this Use Case is to assist the System operator in how to identify and isolate fault areas as quickly as possible and restore an optimal number of customers through alternative power routing, if available. After the fault is resolved, the system operator restores the system to normal conditions. This Use Case simulates this process and documents the results.

Actors

The following table describes the Actors that are present throughout the Use Cases within this document. Actors include people, systems, devices, and sensors in or affected by the functions.

Actor Name	***Actor Type (person, device, system etc.)***	***Actor Description***
Advanced Distribution Management System (ADMS)	System	A subsystem that is responsible for managing outages including outage grouping of calls and AMI events, confirmation of outages and tracking of assigned crew resources and completion of outage restoration details.
Automated Metering Infrastructure (AMI)	System	The AMI system gathers, and stores information supplied by Smart Meters. It also can ping meters on request, to verify status.
Supervisory Control and Data Acquisition (SCADA)	Application	SCADA controlled/telemetered devices connected to control systems within the control center
System Operator	Person	Individual in charge of distribution operations and user of the Distribution Management System (DMS) and Outage Management System (OMS)
Phasor Measurement Unit (PMU)	Sensor	Device that gathers higher resolution line data
WFI	Sensor	Wireless Fault Indicator – sends status alarm using dedicated RF network to confirm if fault currents were witnessed from strategic points on the distribution network.
OTV (Onramp Total View)	System	Fault indicator data management system.
Advanced Protective Relay	Sensor/Actuator	Advanced Protective Relay, Fault Relay – microprocessor controlled protective device, most often working in conjunction with circuit breakers or switches.
Protective Device	Sensor/Actuator	Service restorers, feeder breakers, Individual device fuses, line fuses, vacuum/gas/air switch (SCADA Only)
PMU Data Concentrator (PDC)	System	System that collects PMU generated data

Triggers

This section details the triggers that can occur during the Wire Down due to vegetation contact scenarios. The triggers listed may occur in one or more scenarios and there is a "many to many" relationships between trigger events and user cases.

Triggering Event	***Primary Actor***	***Pre-Condition***	***Post-Condition***	***Additional Notes***
(Identify the name of the event that started the scenario)	*(Identify the actor whose point-of-view is primarily used to describe the steps)*	*(Identify any pre-conditions or actor states necessary for the scenario to start)*	*(Identify the post-conditions or significant results required to consider the scenario complete)*	*Elaborate on any additional description to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
Overcurrent condition detected.	Protective Device.	System operating normal.	Device opens to protect the network assets from the fault.	Every one of these devices will see the fault, but when properly coordinated, only one device will operate
Power Out condition occurs at some meters.	AMI	System operating normal.	Loss of voltage detected and message sent to AMI system. Meter powers down.	AMI sends event on loss of power and voltage alarm. Not all events will be received.
Under voltage condition occurs at some meters.	AMI	System operating normal.	Sustained under voltage detected and message sent to AMI system.	Sustained voltage duration and voltage limit set in firmware. Not currently sent to NMS.
Continuous monitoring.	PMU	PMU data captures 30 samples per second and sends to distribution substation. Then RTAC logic looks for differential (runs through 3 or 4 scenarios) and de-energizes the line.	Differential is detected and device operates to protect the system.	Information goes to Advanced SCADA. NMS doesn't receive the alarm information but receives the device operation.
Fault current detected.	WFI	System operating normal.	Over current (Fault level) followed by sustained outage generates an alarm	SDG&E has approximately 2300 devices. WFI will only report a loss of

Triggering Event	*Primary Actor*	*Pre-Condition*	*Post-Condition*	*Additional Notes*
			that is reported asynchronously to OTV.	current after 3 minutes. Current parameter settings are the default settings. Currently the data is not getting into NMS.
Fault current detected.	Advanced Protective Relay	System operating as normal.	Information stored in a flat CEV file. Tree structure, need to walk down the tree to find. Files are automatically sent, and an email notification is sent to notify that a file has been added. Information is also stored in a database.	May not be available at the time of the fault. Could create an email box with an API to send a notification. No information is sent to NMS.
Continuous monitoring.	Power quality meters	System operating as normal.	Picks up harmonic information, high speed current voltage waveforms.	

Use Case #5 - System Overload Mitigation Description

This Use Case details the process performed during an electric power issue on the grid and the steps taken to resolve the issue and/or complete the restoration during a power outage. The issue is analyzed by system operators using data gathered from the network and other communications such as customers reporting a power outage. The inputs to the Use Case are called Actors and the name, type and description of these Actors are described in the table below. To build this Use case, SDG&E provided a real-world network issue experienced by system operators. The situation was discussed during workshops held to gather information regarding the existing processes, sources of data and how the information is used by the system operators. The steps are captured below identifying the process performed to identify the issue, location, and ultimately restore power. The Use Case details are designed to use as a step-by-step simulation guide to explore options and simulate a process assisting the System operators in identifying and isolating faulted areas as quickly as possible.

The goal of the system operator is to identify these situations, ascertain the cause, and take corrective action as needed to ensure that as many customers as possible remain energized and the distribution system infrastructure is properly protected. Once the overload condition is corrected, the system operator monitors the situation to take further action if necessary. Once the loading has abated, the operator returns the system to its normal configuration. Ideally, the overload is mitigated with no outages to customers

This Use Case details the scenarios for System Overload Mitigation.

Actors

The following table describes the Actors that are present throughout the Use Cases within this document. Actors include people, systems, devices, and sensors in or affected by the functions.

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Advanced Distribution Management System (ADMS) - Outage Management System (OMS)	System	A subsystem that is responsible for managing outages including outage grouping of calls and AMI events, confirmation of outages and tracking of assigned crew resources and completion of outage restoration details.
Automated Meter Information System (AMI)	System	The AMI system gathers, and stores information supplied by Smart Meters. It also can ping meters on request, to verify status.
Supervisory Control and Data Acquisition (SCADA)	Application	SCADA controlled/telemetered devices connected to control systems within the control center
OSISoft PI Historian (Historian)	Application	Data archive system
System Operator	Person	Individual in charge of distribution operations and user of the Distribution Management System (DMS) and Outage Management System (OMS)
Line Crew	Person	Individual(s) working alone or with other personnel to operate the distribution system under the direction of a system operator; includes both electric troubleshooters (ETS) and repair crews
WFI	Sensor	Wireless Fault Indicator – sends status alarm using dedicated RF network to confirm if fault currents were witnessed from strategic points on the distribution network. Also, WFI provide low resolution load data synchronously every 24 hours.

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Advanced Protective Relay	Sensor/Actuator	Advanced Protective Relay, Fault Relay – microprocessor controlled protective device, most often working in conjunction with circuit breakers or switches.
OTV (Onramp Total View)	System	Fault indicator RF Network and data management system

Triggers

This section details the triggers that can occur during the System Overload Mitigation scenarios. The triggers listed may occur in one or more scenarios and there are many relationships between trigger events and Use Cases.

Triggering Event	*Primary Actor*	*Pre-Condition*	*Post-Condition*	*Additional Notes*
(Identify the name of the event that started the scenario)	*(Identify the actor whose point-of-view is primarily used to describe the steps)*	*(Identify any pre-conditions or actor states necessary for the scenario to start)*	*(Identify the post-conditions or significant results required to consider the scenario complete)*	*Elaborate on any additional description to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
Distribution transformer experiences overload	System Operator	System operating normally, but loading increases due to some stimulus such as abnormally cold or warm weather, or cloud cover restricting output of DER	Transformer experiencing oil and insulation degradation due to excess heat from electrical loading over its steady-state operational limit.	
Downstream device experiences overload condition that is detected by SCADA (threshold is exceeded causing alarm in real time)	System Operator	System operating normally, but loading increases due to some stimulus such as abnormally cold or warm weather, or cloud cover restricting output of DER	Device experiences high temperatures and electrical stress, potentially causing immediate failure or otherwise accelerating need for replacement; mitigation steps have taken place such as switching and/or load curtailment	SCADA alarms and PI e-mails are generated to initiate the process of overload mitigation
Downstream device experiences overload condition	System Operator	System operating normally, but loading increases	Device experiences high temperatures and electrical stress,	Customer calls are often the initiating event but are not

Triggering Event	*Primary Actor*	*Pre-Condition*	*Post-Condition*	*Additional Notes*
that is not reported by SCADA		due to some stimulus such as abnormally cold or warm weather, or cloud cover restricting output of DER	potentially causing immediate failure or otherwise accelerating need for replacement; mitigation steps have taken place such as switching and/or load curtailment	reliable for overload detection
Circuit breaker or substation bus experiences reverse power flow	System Operator	System operating normally, but generation downstream of the breaker or substation bus has exceeded the current load, for example due to mild, sunny weather on a bank holiday in an area of high solar penetration	Circuit breaker or substation bus experiences power flow in the reverse direction	No action taken currently. Often no action is necessary.

System Overload Mitigation

Distribution substation transformer overload

- Have “watch list” limits for summer with switching steps to off load (shifting load among adjacent circuits/substations). In some cases, to prevent issues, proactively shifting loads.
- List is provided in the summertime on a weekly basis
- Electric Vehicles do not affect load, they charge at night when TOU rates are beneficial. Do not have to notify utility if they have an EV. Will have to notify utility if they replace/upgrade panel. Don’t have to notify if they add a circuit to an existing panel.
- Has over 1600 megawatts of solar on their system, adding 15-20 MW every month (over 2000 projects per month)
- Use overall system load, review peak loads, review anything that controls the voltage
- This happens while everyone is busy, crew resources may be difficult to find.

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*

Step #	*Actor*	*Description of the Step*	*Additional Notes*
1	Advanced Protective Relay or other line or device sensor	Sends loading data and/or alarms to SCADA	Limits are seasonal
2	SCADA	Triggers an overcurrent alarm if data exceeds a preset threshold SCADA data sent to PI database	PI most likely uses this data to make longer-term assessments of substation transformer loading conditions
3	AMI	Sends periodic usage information to AMI system.	Information available for distribution line transformer load management
4	WFI	Load data from WFI is available every 24 hours, in one-hour increments.	
5	Weather Station Data	Meteorology data.	
6	Historian	PI sends email to leadership	PI identifies overloaded assets using data from SCADA; will need to understand if other data sources such as AMI are also considered
7	System Operator	Determines either through direct SCADA alarm or loading calculations that overload exists or will occur. Operator investigates and if necessary, takes steps to alleviate the overload	Use NMS switch plans, DER load plans, NMS suggested switching done under real time.
8	System Operator	If no steps are necessary, there may be a device giving false reads, there may be some maintenance work being done; operator makes note	Operator is aware of maintenance if NMS has switch plans
9	System Operator	If steps are necessary, analysis/trend has happened for several days, may shift load by proactively switching	Review watch list suggested switching and plan day of week, time of week, for plan of action.
10	System Operator	When the event subsides (ex: temperature moderates), network is returned to normal configuration.	May run abnormal for duration of summer
11	System Operator	If other mitigation steps do not relieve the overload condition, consider load shed	Discussion between manager & operator

Overload rapidly approaching limits (SCADA)

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Advanced Protective Relay or other line or device sensor	Sends loading data and/or alarms to SCADA	Limits are seasonal
2	SCADA	Triggers an overcurrent alarm if data exceeds a preset threshold SCADA data sent to PI database	
3	WFI	Load data from WFI available every 24 hours in one-hour increments	
4	Weather Station Data	Meteorology data.	
5	System Operator	Determines either through direct SCADA alarm or loading calculations that overload exists or will occur. Operator investigates and if necessary, takes steps to alleviate the overload	Use NMS switch plans, DER load plans, NMS suggested switching done under real time.
6	System Operator	If no steps are necessary, there may be a device giving false reads, there may be some maintenance work being done; operator makes note	Operator is aware of maintenance if NMS has switch plans
7	System Operator	If steps are necessary, analysis has happened for several days, may shift load by proactively switching	Reactive situation, not involving days of watching/analysis. Watch list will not be used in this situation.
8	System Operator	When the event subsides (ex: temperature moderates), network is returned to normal configuration.	May run abnormal for the duration of summer
9	System Operator	If other mitigation steps do not relieve the overload condition, consider load shed	Discussion between manager & operator

Non-SCADA overload

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Customer Contact Center	Receives customers calls, enters call information into CIS and/or Trouble Call Entry	A couple of calls are not on the operator's "radar". Mostly happen on 4kv circuits. Main customer complaint during overload is lower voltage
2	NMS	Receives call information from customer calls and creates non-outage event	
3	System Operator	Checks current weather conditions	If weather is in the extreme, then we know it may be overload.
4	System Operator	Operator investigates and if necessary, takes steps to alleviate the overload	Use NMS switch plans, DER load profile, NMS suggested switching done under real-time.
5	System Operator, Line Crew	ETS is sent to investigate overload conditions and report back	
6	System Operator, Line Crew	If steps are necessary, may upgrade fuse, if that does not work, may shift load to adjacent circuit, if feasible	Reactive situation, not involving days of watching/analysis. Watch list will not be used in this situation.
7	System Operator	When the event subsides (ex: temperature moderates), network is returned to normal configuration (if applicable)	May run abnormal for duration of summer
8	System Operator	If other mitigation steps do not relieve the overload condition, consider load shed	Discussion between manager & operator

System Overload Mitigation Reverse Flow

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Advanced Protective Relay	Reverse real power flow detected that exceeds acceptable limit.	Reports to SCADA
2	SCADA	Creates alarm condition that reverse flow has been detected	
3	System Operator	Operator acknowledges alarm	Just for awareness, no other action taken

Use Case #6 – Underground Distribution Description

This Use Case details the process performed during an electric power issue on the grid and the steps taken to resolve the issue and/or complete the restoration during a power outage. The Issue is analyzed by system operators using data gathered from the network and other communications such as customers reporting a power outage. The inputs to the Use Case are called Actors and the name, type and description of these Actors are described in the table below. To build this Use case, SDG&E provided a real-world network issue experienced by system operators. The situation was discussed during Workshops held to gather information regarding the existing processes, sources of data and how the information is used by the system operators. The steps are captured below identifying the process performed identify the issue, location and restore power. The Use Case details are designed to be used as a step-by-step simulation guide to explore options and simulate a process assisting the System operators in identifying and isolate fault areas as quickly as possible.

This Use Case details the scenario where a fault is detected in the underground network. The underground network accounts for approximately 60% of the existing distribution network. Faults on this part of the network are typically phase-to-ground faults. The common faults are a result of:

- Cables deteriorating over time (moisture ingress common on older cables)
- Connector failures (due to defect during manufacture or installation and with age)

Such underground outages are most commonly phase-to-ground faults. Faults can sometimes be associated with significant rainfall leading to water integrity issues for connectors. “T” connectors are more prone to fail than the feeder cables themselves. The number of these devices on the network is so great that cost effective replacement via maintenance programs is not achievable.

With underground faults there is potentially less information available. This is due to a lack of visibility of the fault area (as opposed to the overhead network where you might get information from passers-by seeing a wire down or arcing/sparking).

Actors

The following table describes the Actors that are present throughout the Use Cases within this document. Actors include people, systems, devices, and sensors in or affected by the functions.

Actor Name	***Actor Type (person, device, system etc.)***	***Actor Description***
Advanced Distribution Management System (ADMS) - Outage Management System (OMS)	System	A subsystem that is responsible for managing outages including outage grouping of calls and AMI events, confirmation of outages and tracking of assigned crew resources and completion of outage restoration details.
Automated Meter Infrastructure (AMI)	System	The AMI system gathers, and stores information supplied by Smart Meters. It also can ping meters on request, to verify status.
Supervisory Control and Data Acquisition (SCADA)	Application	Constant connection to SCADA capable devices to monitor and control.
System Operator	Person	Individual in charge of distribution operations and user of the Distribution Management System (DMS) and Outage Management System (OMS)
Trouble Shooter (ETS)	Person	Initial field staff sent to location to execute field operations, locate faults, and execute the operator’s restoration plan
Phasor Measurement Unit (PMU)	Sensor	Device that gathers higher resolution line data
Fault Current Indicators (FCI)	Sensor	The indicators used in the Underground distribution network are basic devices that will indicate the presence of a fault current. Typically, these will be indicated by a semaphore or flashing light. They are not presently wireless.
Protective Device.	Sensor/Actuator	Service restorers, feeder breakers, Individual device fuses, line fuses, vacuum/gas/air switch, (SCADA only)
PQ Meter	Sensor	Field equipment used by SDG&E

Actor Name	***Actor Type (person, device, system etc.)***	***Actor Description***
Fault Location Specialist	Person	Expert team with specific equipment and training to find locations of underground faults
Trouble Shooter	Person	First crew on the scene. Investigates potential fault locations and confirms protection operations or not

Triggers

This section details the triggers that can occur during the Underground fault scenarios. The triggers listed may occur in one or more scenarios and there are many relationships between trigger events and Use Cases.

Triggering Event	***Primary Actor***	***Pre-Condition***	***Post-Condition***	***Additional Notes***
(Identify the name of the event that started the scenario)	*(Identify the actor whose point-of-view is primarily used to describe the steps)*	*(Identify any pre-conditions or actor states necessary for the scenario to start)*	*(Identify the post-conditions or significant results required to consider the scenario complete)*	*Elaborate on any additional description to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
Overcurrent condition detected.	Protective Device.	System operating normal.	Device opens to protect the network assets from the fault.	Every one of these devices will see the fault, but when properly coordinated, only one device will operate.
Power Out condition occurs at some meters.	AMI	System operating normal.	Loss of voltage detected, and message sent to AMI system. Meter powers down.	AMI sends event on loss of power and voltage alarm. Not all events will be received.
Under voltage condition occurs at some meters.	AMI	System operating normal.	Sustained under voltage detected and message sent to AMI system.	Sustained voltage duration and voltage limit set in firmware. Not currently sent to NMS.
Fault current detected.	Advanced Protective Relay	System operating as normal.	Information stored in a flat CEV file. Tree structure, need to walk down the tree to find. Files are automatically sent, and an email	May not be available at the time of the fault. Could create an email box with an API to send a notification. No

Triggering Event	Primary Actor	Pre-Condition	Post-Condition	Additional Notes
			notification is sent to notify that a file has been added. Information is also stored in a database.	information is sent to NMS.
Continuous monitoring.	Power quality meters	System operating as normal.	Picks up harmonic information, high speed current and voltage waveforms.	

Underground Distribution Network Faults Scenarios

The following scenarios have been identified for the Use Case based on current state workshops completed:

- Trip/reclose – A SCADA monitored/controlled Recloser trips open and successfully recloses
- Trip/lockout – A SCADA monitored/controlled Recloser trips open and fails to successfully reclose after a pre-determined number of attempts.
- Non-SCADA device operates – no SCADA information available to detect the fault

The following sections detail the scenarios above listing the sequence of events that takes place during the restoration process.

Trip and Successful Reclose

This scenario details the actions, inputs and received information in a scenario where a SCADA controlled/telemetered Protection device (namely an auto reclosing breaker) opens and successfully recloses. In this scenario the recloser opened and reclosed but the fault was not cleared and another protection device (i.e., a fuse) has operated clearing the fault downstream. Power is still provided upstream from the clearing protective device and the reclosing device is closed.

Step #	Actor	Description of the Step	Additional Notes
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc., may also be noted in this column.*

Step #	***Actor***	***Description of the Step***	***Additional Notes***
1	Protection device	Telemetered Protection device trips open on fault. NMS is aware via SCADA of the trip. No action at this point as the device has ARP (configured in NMS as momentary capable). First reclose is at 5 seconds, second shot is at 45 seconds to allow downstream automatic isolation to occur.	
2	NMS	A timer is started to time the ARP within NMS.	ARP – Auto reclose process – the process associated with equipment that can automatically reclose when tripped open
3	Protective device	ARP closes in the device automatically. NMS is aware via SCADA, but no action taken	
4	NMS	The NMS timer expires, and device remains closed. AR process is complete.	Assuming a downstream device operates clearing the fault.
5	NMS	NMS creates a Real Momentary Outage (RMO) recording the fact that an Auto-recloser operated and successfully reclosed.	
6	NMS	NMS creates one or more predicted fault locations and visually indicates potential locations on NMS model upon fault current measurement from Advanced Protective Relay. NMS generates an additional alert for the operator from the FLA function.	
7	System Operator	The operator can display the possible locations based on distance to fault calculations, on the NMS network diagram and use this to start the patrols.	
In this scenario, to allow the reclose to be successful, it is assumed a downstream device has operated. This could result in operators receiving alerts related to low measurements at the feeder head due to lack of load further downstream. ***It is assumed that although the auto-recloser successfully closed, there is still a downstream outage. Steps to identify and resolve this outage are detailed in the following use cases. The type of downstream device will determine which use case applies (i.e., Telemetered/tele-controlled (SCADA) device, or manual only device)***			
8	System Operator	The operator takes the necessary actions to complete the RMO capturing relevant data for reporting and audit purposes	Typically, this will be complete on resolution of the downstream outage. Until the downstream outage is identified, it is

Step #	Actor	Description of the Step	Additional Notes
			unknown if the recloser needs to be operated again to allow remedial work

Trip & Lockout

This scenario details the steps and triggers for an event where an auto-recloser trips, attempts to reclose several times, trips a final time and stops in an open and locked out state.

Step #	Actor	Description of the Step	Additional Notes
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Protection device	Telemetered Protection device trips open on fault. NMS is aware via SCADA of the trip. No action at this point as the device has ARP	
2	NMS	A timer is started to time the ARP within NMS	
3	Protective device/NMS	Before the ARP timer is complete, the protection device trips open again	
4	Protective device/NMS	AR Processing may attempt to reclose again	
5	Protection device	Protection device trips open for the final time in the AR process. The breaker remains open and in a lockout state. AR processing is complete	
6	NMS	NMS creates an RDO associated with the protection device. Details of the operations are recorded including time of the first event. Scope of the outage is calculated based on the NMS model and a visual indication of the scope is present on the viewer. The event is listed in the work agenda	
As the recloser has locked out, the outage is confirmed, and scope identified. From this point, the operators will carry out various activities to identify the fault area and take corrective action. The NMS system will receive several AMI messages where possible and potentially customer/non-customer calls with information related to the wire down. ***The identification actions are documented in the following use cases.***			

Non-SCADA Device Operates

The following scenario describes the steps to resolve an underground network fault event. The initial steps describe how information is obtained via SCADA on a protection device during an unplanned operation. Protective devices do not always operate, and the issue could be that a downstream non-SCADA event has occurred with no notification from SCADA. In this situation, due to a loss of load measured by SCADA at the feeder head, limits may be breached indicating something downstream has operated.

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Protection device	A manual (non-SCADA) protection device on the network operates due to the detection of a fault current	Operators/NMS are not aware of this situation at this time
2	FIs	Where present on the network, FIs will activate.	These FIs are visual indicators only. No information is sent to systems within the Control Center
3	AMI	Messages from the AMI system are sent to the NMS system to make operators aware of the outage	
4	NMS	Several meter “no voltage” messages are received from the AMI system	Meter Power Off messages will be subject to filtering rules, for example: - Less than 10 minutes of outage start time - If more than one Power Off message exists and are within 90 seconds of each other (exception where only 1 meter is associated with a transformer)
5	NMS	Based on the meter messages, a predicted device outage (PDO) is created, and the predicted device is determined	

Step #	*Actor*	*Description of the Step*	*Additional Notes*
6	System Operator	Operator investigates the messages and the information in the PDO. Based on this information he sends a Trouble Shooter out to the device identified by NMS as the source (predicted device)	
7	Customer	Several customers call in reporting interruption to power	
8	NMS	The received calls are automatically associated with the outage event assuming they are within the same scope of network	
9	System Operator	The system operator shares the location of underground FIs and instructs the Trouble shooter to investigate	
10	System Operator/NMS	The system operator analyses the data received to narrow down the fault location. The operator then dispatches a Fault location specialist to find the exact fault location	
11	System Operator/NMS	Once the fault location is identified, the operator instructs crews to various locations to isolate the fault area and to restore as many customers supply as possible. The NMS system is updated throughout restoration to maintain a record and keep operators up to date on progress	
12	System Operator	The operator then plans and works with the field crews to repair the fault (i.e., replace the damaged cable)	

Use Case #7 High Voltage (Primary Metered) Customer Problem

This Use Case details the process performed during an electric power issue on the grid and the steps taken to resolve the issue and/or complete the restoration during a power outage. The Issue is analyzed by system operators using data gathered from the network and other communications such as customers reporting a power outage. The inputs to the Use Case are called Actors and the name, type and description of these Actors are described in the table below. To build this Use case, SDG&E provided a real-world network issue experienced by system operators. The situation was discussed during Workshops held to gather information regarding the existing processes, sources of data and how the information is used by the system operators. The steps are captured below identifying the process performed to identify the issue, location and then to ultimately restore power. The Use Case details are designed to use as a step-by-step simulation guide to explore options and simulate a process assisting the System operators in identifying and isolating faulted areas as quickly as possible.

This Use Case details the scenarios for managing a primary metered customer outage. A Primary Metered Customer is a single customer (for example an Industrial Unit) or a private customer network. The responsibility of the Distribution company is to ensure power to the connection point from the network to the customer. Any issues/maintenance within the private network is the responsibility of the customer.

Actors

The following table describes the Actors that are present throughout the Use Cases within this document. Actors include people, systems, devices, and sensors in or affected by the functions.

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Advanced Distribution Management System (ADMS	System	A subsystem that is responsible for managing outages including outage grouping of calls and AMI events, confirmation of outages and tracking of assigned crew resources and completion of outage restoration details.
Automated Meter Infrastructure (AMI)	System	The AMI system gathers, and stores information supplied by Smart Meters. It also can ping meters on request, to verify status.
Supervisory Control and Data Acquisition (SCADA)	Application	SCADA controlled/telemetered devices connected to control systems within the control center
System Operator	Person	Individual in charge of distribution operations and user of ADMS and SCADA
Phasor Measurement Unit (PMU)	Sensor	Device that gathers higher resolution line data
Fault Current Indictors (FCI)	Sensor	Fault current indicators
PQ Meter	Sensor	Power Quality Meter

Triggers

This section details the triggers that can occur during the primary metered customers scenario. The triggers listed may occur in one or more scenarios and there is a many to many relationships between trigger events and Use Cases.

Triggering Event	***Primary Actor***	***Pre-Condition***	***Post-Condition***	***Additional Notes***
(Identify the name of the event that started the scenario)	*(Identify the actor whose point-of-view is primarily used to describe the steps)*	*(Identify any pre-conditions or actor states necessary for the scenario to start)*	*(Identify the post-conditions or significant results required to consider the scenario complete)*	*Elaborate on any additional description to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
Overcurrent condition detected.	Protective Device.	System operating normal.	device opens to protect the system from the fault.	Every one of these devices will see the fault, but when properly coordinated, only one device will operate
Power Out condition occurs at meter.	AMI	System operating normal.	Loss of voltage detected, and message sent to AMI system. Meter powers down.	AMI sends event on loss of power and voltage alarm. Not all events will be received. All voltage and power alarms are received near real time (within a minute).

Primary Metered Customer Problem

The following scenario has been identified for the Use Case produced based on current state completed:

- Primary Metered Customer Outage – A Primary Metered customer network is experiencing an outage

The following section details the scenario above listing the sequence of events that takes place during the service restoration process.

This scenario details the processes involved in investigating a Primary Metered Customer outage. In this case, the Primary Metered Customers network is not represented in the network model, however, the utility owned switchgear distributing power to the Primary Metered Customer is modelled and potentially has SCADA. *Not all primary metered customers are served through SCADA capable devices.*

Step #	***Actor***	***Description of the Step***	***Additional Notes***
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Protection device	The protection device owned by the customer operates (trips open). Alternatively, a utility owned/operated device immediately ahead of the customer trips. In extreme cases, service to other customers may be interrupted.	
2	NMS	The NMS system receives a trip open from the protection device at the customers location via the SCADA system and creates an event	In the event there is no SCADA information, the Operators will receive notification via a call
3	System Operator	The operator checks the feed going to the switch gear and confirms, *where possible* that the feeder is energized	
4	System Operator	Where possible, the operator calls the Primary Metered Customer to discuss the fault condition. Any actions are recorded in the NMS event	
5	System Operator	If required, the system operator dispatches a Trouble Shooter direct to the Primary Metered Customer site to confirm power is coming in from the feeder side of the switch gear. The actions are recorded in the event in NMS	
6	Trouble shooter	The trouble shooter confirms to the Primary Metered Customer that the supply is good and advises they contact their electrician to diagnose and resolve a potential down-stream incident or an issue with their switch gear.	
In the scenario where the system operator or Trouble Shooter discovers there is a loss of power to the feed for the Primary Metered Customer, the steps in the related use case “UC01 – Wire-down” would be followed to identify and resolve the fault condition.			

EPIC Final Report

Program	Electric Program Investment Charge (EPIC)
Administrator	San Diego Gas & Electric Company
Project Number	EPIC-3, Project 4
Project Name	Safety Training Simulators with Augmented Visualization
Module Name	Module 2, Virtual Reality Training Simulator for Personal Protective Grounding/Equal Potential Zones on the Electric Distribution Underground System
Date	December 31, 2021

Attribution

This comprehensive final report documents the work done in Electric Program Investment Charge (EPIC) in Project 4 of the portion of EPIC funds administered by SDG&E in the third EPIC cycle (EPIC-3). The project team that contributed to the project definition, execution, and reporting included the following individuals, listed alphabetically by last name:

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Executive Summary

The objective of SDG&E's EPIC-3 Project 4 on "Safety Training Simulators with Augmented Visualization" was to demonstrate and evaluate augmented reality applications for field focused design, operations, asset monitoring, and management solutions. It demonstrated the ability of the latest simulator technologies to train utility industry personnel on safety-related issues, including electric potential zones and grounding techniques associated with construction work practices. The project was divided into two modules. This project covers the second module which was to conduct a pre-commercial demonstration of a field worker safety training system using virtual reality technology to immerse students more thoroughly in safety procedures related to work with de-energized underground distribution lines.

- Module 2 of this project explored virtual reality applications for field focused design, operations, and asset monitoring and management solutions, and how Virtual Reality tools can be utilized to demonstrate its ability to train utility industry personnel on safety related issues, such as Equal Potential Zones (EPZ) and grounding techniques associated with current construction work practices and provide rich contextual information at the point of work.

The following were demonstrated in Module 2:

- A Virtual Reality for each scenario
  Demonstrate the new training simulator's ability to guide one or more students using wireless Virtual Reality (VR) goggles with virtual hands through five different scenarios.
- A two-dimensional training simulator for each scenario
  Demonstrate how students are able to complete the training in a two-dimensional environment.
- A learning management system (LMS) for each scenario
  Demonstrate the simulator's ability to assist the student through the five scenarios.

The demonstration of VR training methods showed improvement in almost every criterion assessed as a success factor including information retention, situational awareness, level of engagement, content clarity, and participant's level of confidence

Along with confirmed success factors discussed above, a few challenges were noted.

- Initial increase in training costs
- Employee learning curve to adapt to new technology
- Employees with little or no previous experience with VR or similar technologies

Overall, the system demonstrates an effective and improved training method over traditional training methods that utilize only text and training videos. The VR training comes a step closer to real time hands-on experience, without the associated risks, enabling the trainee to learn the procedures in a safer environment. As a result, the participants showed an increased level of confidence, making VR training a very effective approach.

This EPIC project has ended. It is recommended that the VR training method be pursued commercially for its effectiveness in training employees from the trade on grounding and EPZ procedures unique to electric underground distribution. It is recommended that follow-up work be pursued to establish a path to commercialization. The appropriate internal SDG&E stakeholder group should be given the lead responsibility for managing the commercialization process.

Logical “next steps” towards commercialization would include:

- Setting up a permanent resource team to accomplish commercialization
- Arranging funds for commercial adoption and on-going maintenance of commercial operations
- Developing a commercialization plan

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List of Acronyms

Acronym	Acronym Description
AR	Augmented Reality
CPUC	California Public Utilities Commission
EPIC	Electric Program Investment Charge
EPZ	Equal Potential Zone, or Equipotential Zones
LMS	Learning Management System
PPG	Personal Protective Grounding
SDG&E	San Diego Gas & Electric
UG	Underground
VR	Virtual Reality

1.0 Project Objectives

The objective of SDG&E's EPIC-3 Project 4 on "Safety Training Simulators with Augmented Visualization" was to demonstrate and evaluate augmented reality applications for field focused design, operations, asset monitoring, and management solutions. It demonstrated the ability of the latest simulator technologies to train utility industry personnel on safety-related issues, including electric potential zones and grounding techniques associated with construction work practices. The project was divided into two modules. This project covers the second module which was to conduct a pre-commercial demonstration of a field worker safety training system using virtual reality technology to immerse students more thoroughly in safety procedures related to work with de-energized underground distribution lines.

Module 2 of this project explored virtual reality applications for field focused design, operations, and asset monitoring and management solutions, and how Virtual Reality tools can be utilized to demonstrate its ability to train utility industry personnel on safety related issues, such as Equal Potential Zones (EPZ) and grounding techniques associated with current construction work practices and provide rich contextual information at the point of work.

2.0 Issues and Policies Addressed

The primary issue addressed for this project was to explore more effective training methodologies using new simulation technologies that use augmented or virtual reality and quantify their effect on parameters like public and personnel safety, training time and associated costs, field workforce readiness, and associated benefits in managing an electrical distribution underground system.

State, and specifically, CPUC policy towards an increased role in promoting safety for utility operations has led to a greater emphasis for utility leadership to focus on this area. For contracted as well as regular employee work, utilities are expected to perform effective oversight on all work practices. Due to the nature of the work, many utility workers interact daily with scenarios that, if handled improperly, can lead to life-changing, or life-ending, outcomes. The application of contemporary technology to promote the readiness of these workers supports state policy. Opportunities to add new technologies that may enhance contemporary practices are explored through projects such as this one.

3.0 Project Focus

The focus of this project is to perform a pre-commercial demonstration of augmented reality applications for field-focused design, operations, and asset monitoring and management solutions. The project will demonstrate the ability of the latest simulator technologies to train utility industry personnel on safety-related issues, such as equal potential zones (EPZ) and grounding techniques associated with construction work practices. The demonstration will include utilization of augmented reality tools to visualize and provide rich contextual information within the delivery of the training.

4.0 Project Scope Summary

The scope of this module was to demonstrate a VR pre-commercial training stimulator for Personal Protective Grounding/ Equal Potential Zone (PPG/EPZ) on the electric distribution underground (UG) system. This new training will be used for students initial and/or refresher compliance training to understanding of the procedures for PPG/EPZ. The case for prospective commercial adoption of the training was examined. This comprehensive final report provides documentation of the module approach, demonstration results, final benefits estimate, value proposition, and recommendations regarding commercial adoption.

This training simulator guides one or more students using VR goggles through five different EPZ and grounding techniques. These five different scenarios go from simple to very complex EPZ and grounding techniques. The simulator would be able to assist students through the five following scenarios:

- Replace an elbow in a handhole with jacketed cable.
- Replace a run of cable between two handholes with jacketed cable.
- Replace a “T” in a handhole with unjacketed and jacketed cable.
- Replace a live front piece of equipment to a dead front with unjacketed and jacketed cable.
- Change a four-way pad mount switch with jacketed cable

5.0 Approach for Project Module 2 Activity

The approach for this project included the following tasks, designed to demonstrate a functioning precommercial training simulator for utilizing PPG/EPZ methods on the electric distribution underground (UG) system.

Task 1 - Initiation of Project Plan

- Identification of stakeholders
- Project kick-off, development of project plan, resource requirements, and formation of internal project team

Task 2 - Development of Project Requirements

- Fact finding from literature or other programs
- Baselining current situation and practices

Task 3 - Development of Funding Base and Collaborative Funding or Partner Arrangements

- Examine opportunities for partnering and cost sharing to enable more work to be done in simulation and visualization development.

Task 4 - Contractor Procurement

- Select a qualified contractor(s) to assist with engineering support services related to the project.

Task 5 - Site Selection and Arrangement for the Safety Training Simulation and Visualization Equipment (Hardware and Software)

- Select a preferred site

Task 6 - Preparation of Use Cases and/or Test Plan for Demonstration

- Preparation of Use Case(s) to define the content of the demonstration and to ensure all benefits will be measured in the project.

Task 7 - Development of Test Set-up and Safety Training Simulation/Visualization Modeling Capability Support

- Testing and measurement for scenarios in use cases
- Procure equipment and software

Task 8 - Execution of Demonstration

- Perform the demonstration of the VR technology
- Perform trial run of the training scenarios

Task 9 – Analysis of Data and Other Demonstration

- Assessment of effectiveness of the VR technology and training

Task 10 - Development of Conclusions and Recommendations

- Use the results of the data analysis task to update the initial benefits analysis and to formulate key findings, conclusions, and recommendations for the project. This material will be integrated into the comprehensive final report for the project.
- Determine the relative value proposition for each use case.

Task 11 - Preparation and Implementation of Tech Transfer Program for Deployment Site

- Develop, prepare, and implement a tech transfer plan
- Identify the process for transferring project results into practical use by SDG&E, as well as by other potential users.
- The tech transfer plan should be consistent with the recommendations made regarding which use case should and should not be pursued commercially.

Task 12 - Perform Interim Project Reporting

- Perform required interim reporting activities, throughout the life of the project.

Task 13 – Disposition Plan for Equipment and Software

- Define and implement a disposition plan for equipment and software used in the project

Task 14 - Preparation of the Comprehensive Final Report

- A comprehensive final report shall be prepared that captures the objective, initial benefits analysis and value proposition, description of the metrics and use cases, demonstration results, data analysis, final benefits estimate and value proposition, conclusions, and recommendations regarding commercial adoption.
- Prepare a draft report for review and a revised final version of the comprehensive final report for Module 2.

5.1 Baseline Studies/Fact Finding

5.1.1 Initial Benefit Estimate and Value Proposition

The goal of Module 2 was to demonstrate use of virtual-reality visualization tools to aid in training field employees in safe practices for working situations where there is the possibility of unexpected hazardous levels of electric potential. The case for prospective commercial adoption of the training will be examined. The following were the identified initial project benefits and value proposition:

Safety to SDG&E's Personnel

- With the VR simulator, SDG&E would be able to provide initial and refresher training to more employees on the proper procedures of doing PPG/EPZ on distribution UG.

Safety to the Public

- With the VR training, SDG&E would be able to restore power to the customer more quickly and safely and to reduce public exposure to a potentially energized system, especially first responders.

Risk Reduction

- The VR training would help protect employees from hazardous potentials caused by line induction and/or non-utility generation sites (e.g., photovoltaic systems, wind turbines).

Reduced Cost

- The enhancement of training would help reduce outage times and associated costs, due to the increased skill level of employees.

Value Propositions – SDG&E Electric Operations

Employee training is a constant, critical task that must be executed efficiently and effectively. Employee, and by extension, public safety is a function of how effective these programs are in establishing and maintaining good work habits and conservative approaches to inherently hazardous tasks. Significant injury, loss of life and property can result otherwise.

Value Propositions – State Initiatives

The core duty of the utilities is the safe provisioning of electric service. In the fulfillment of this responsibility, it is imperative that operating utilities strive to protect the public and all employees from the hazards of providing electric energy for beneficial use. Enhancing the ability of operating utilities to keep employee competence and readiness at the highest possible level supports the state's goals related to safety outcomes, by all measures.

Safety is an element of the overall EPIC framework and is specifically stated as an element in the state's Public Utility Code 8360.

Further, promoting the readiness of utility workers as they interact with high-risk electrical hazard scenarios, helps to also ensure the safety of the SDG&E employees.

5.1.2 Initial Selection of Metrics

The following were identified as initial project metrics for measuring success and benefits of the demonstration.

Benefit 1 – Increase in worker effectiveness attributable to the training: The VR training can be a more effective tool in terms of clarity and use of the content, making it more effective compared to traditional methods using presentations and videos only.

a. Benefit description: The VR training displays a more engaging experience for the participants by simulating the real field scenario and therefore makes it easier to visualize, understand and memorize the training instructions. The student experience is far more participatory and immersive, rather than passive.

b. Desired target: Demonstrates increased information retention and increased situational awareness and confidence level by the participants.

Benefit 2 – Safety to SDG&E's Personnel: The VR training provides increased safety to SDG&E's personnel during training.

a. Benefit description: The VR training allows participants to practice the scenarios safely, avoiding exposure to potential hazards.

b. Desired target: Significantly reduces incidents and injuries.

Benefit 3 – Increased number of trained personnel available

a. Benefit description: Increased understanding of PPG/EPZ processes and personnel's ability to perform them in the field to achieve associated benefits like increased jobsite safety and reduction in operation costs.

b. Desired target: Increased number of personnel competent in PPG/EPZ procedures.

5.2 Description of Pre-Commercial Demonstration

5.2.1 Location

The demonstration was conducted at the SDG&E Skills Training Center, in San Diego, California.

5.2.2 Use Cases

Table 1 describes the use cases and the five selected scenarios for testing of the VR and training of EPZ work methods.

Table 1: Use Case Scenarios

Scenario	Use Case	Description
1	Replacing Elbow	The trainees change out a bad load break elbow. To complete this operation, the trainees performed work at two above ground structures using EPZ work methods. Included were a fuse cabinet and dead front terminator. All switching, tagging and holds had been completed. The primary focus was to establish and maintain an EPZ. The last two sentences can be considered common to the other four use cases below and will not be repeated.
2	Replacing Cable Run	The trainees replace a bad run of cable that goes from an above ground structure to a hand hole using EPZ work methods. The trainee began at the switch cabinet where the bad cable originated.
3	Replacing a T connector	Trainees replace a bad 600-amp T connector, which was located inside of a handhole. The trainees worked with both jacketed and unjacketed cable. Using EPZ work methods they performed work within this structure, another handhole and switch cabinet.
4	Live Front to Dead Front Equipment Replacement	Trainees replace a live front terminator containing both jacketed and unjacketed cable with a dead front terminator. Using EPZ work methods trainees performed work at the terminator and within two handhole structures.

Scenario	Use Case	Description
5	Changing a Switch	Trainees change out a four-way pad mounted switch, using EPZ work methods. The work physically occurred at the surface mounted switch, and within two adjacent handholes.

5.2.3 Equipment Requirements

The equipment and software used in the VR Safety Training Simulators is outlined in Table 2.

Table 2: Equipment and Software Requirement

Equipment	Requirement
VR Headsets	Oculus Quest (with developer mode enabled) Facebook (META) account to load software onto headset. Software will work on Oculus Headsets with memory storage, or VR software can run on a PC or Laptop and connect to Oculus or other headsets via Link cable or by streaming using Wi-Fi. A wireless router that supports 5 Ghz operation is required.
Computer	High-end gaming PC or Laptop with discrete graphics card. When running VR, Video card needs to have at least 6GB Video memory.
Virtual Reality Program	Loading of VR software requires an account login, mobile app for mobile device(s) and a PC or Laptop with a software loaded for copying software to VR Headset.

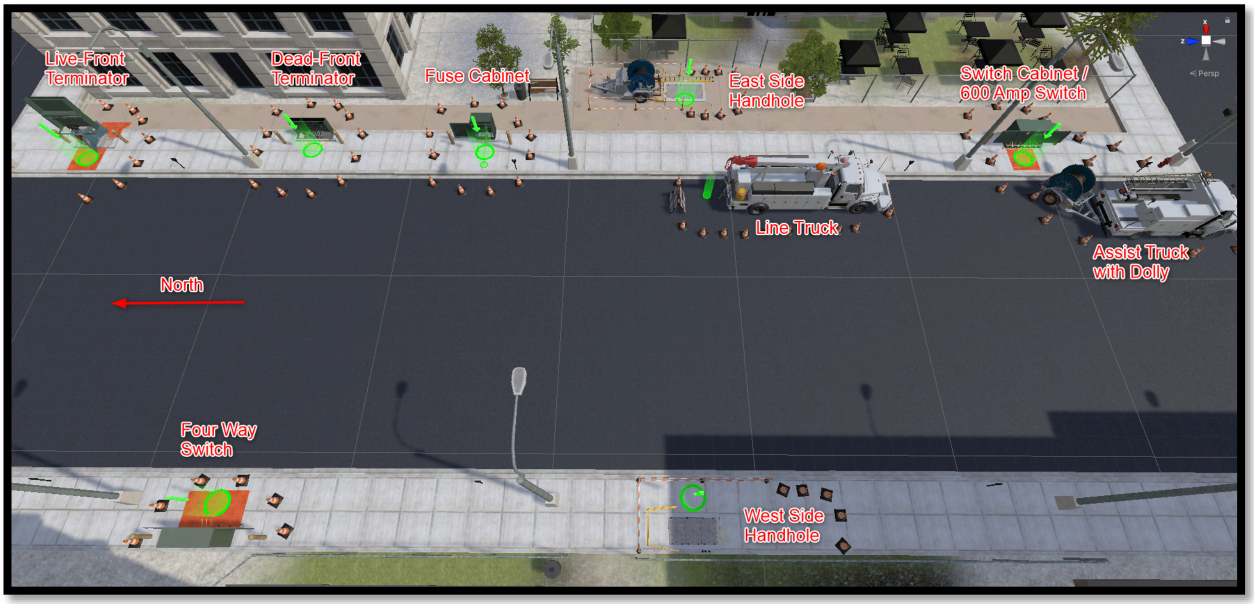
5.2.4 Supporting SDG&E Infrastructure and Data Requirements

SDG&E's infrastructure supported connectivity with above software and hardware using existing PC/Laptops. VR headsets were obtained separately as required by SDG&E and use of the Learning Management System (LMS) was provided by the selected vendor.

5.2.5 Execution of Demonstrations

The training simulator is designed to guide one or more students in using VR googles through five different EPZ and grounding techniques. These five different scenarios go from simple to very complex. The simulator can assist students through the five scenarios, test them on each scenario and retain records that the participant completed the training. The virtual application layout used for five different EPZ and grounding scenarios is shown in Figure 1.

Figure 1: Virtual Application Layout



The five different scenarios are:

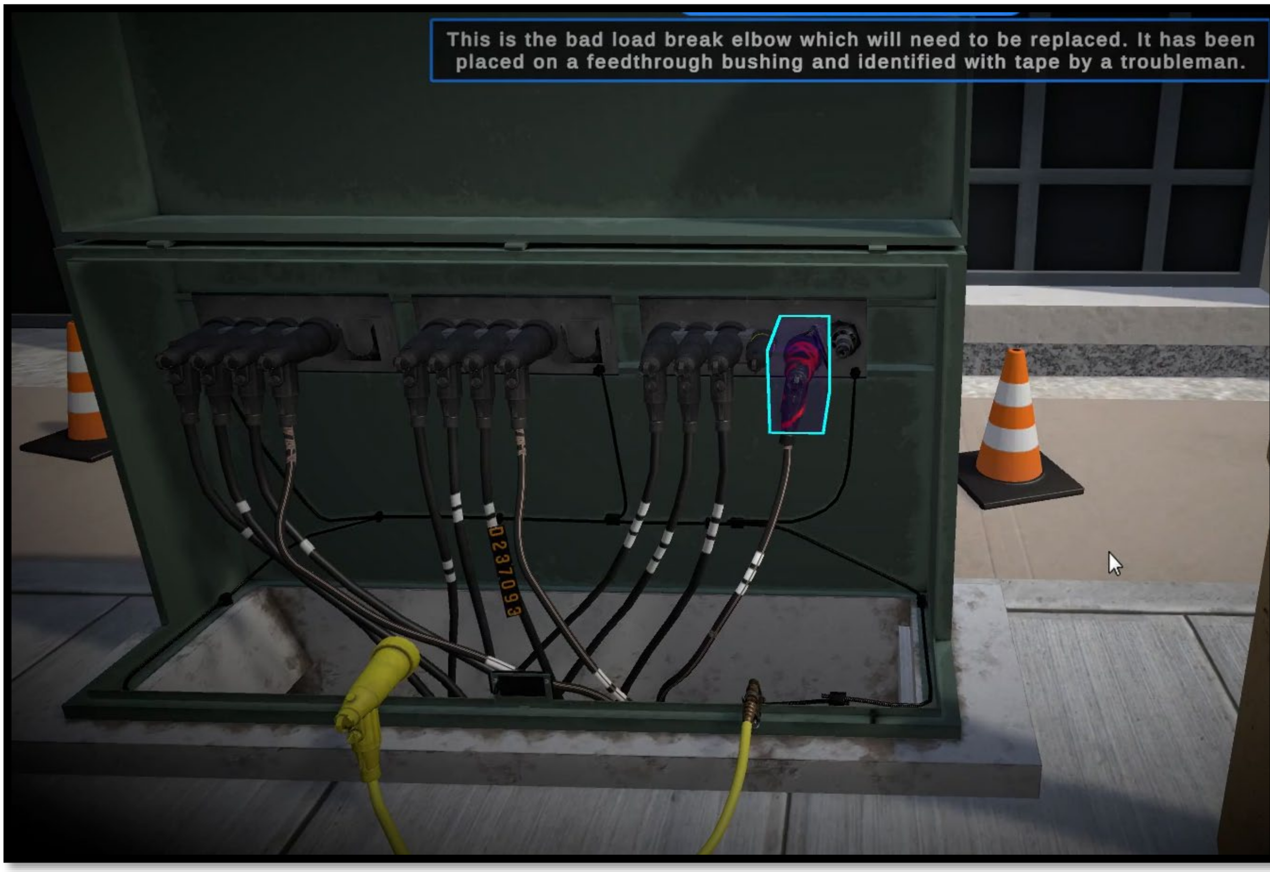
- Replace an elbow in a handhole with jacketed cable.
- Replace a run of cable between a handhole and a switch.
- Replace a "T" connector in a handhole that connects to unjacketed and jacketed cables.
- Replace a live front piece of equipment to a dead front that connects to unjacketed and jacketed cables.
- Change a four-way pad mount switch that is connected to jacketed cables

5.2.6 Use Case Execution

During the simulation, the participants were required to navigate the various structures and click on interactive objects.

In this scenario trainees changed out a faulty load break elbow, shown in Figure 2. To complete this operation, the participant's performed work on two above ground structures using EPZ work methods. Included were the fuse cabinet and dead front terminator. All switching, tagging and holds had been completed. The primary focus was to establish and maintain an EPZ.

Figure 2: Faulty Load Break Elbow



During the simulation, the participants were required to cross the street to investigate various structures. Whenever they crossed the street, it was imperative that the participants check for traffic and follow best practices related to road safety. It showed a list of steps which needed to be completed for the current scenario. The operation order could be collapsed or expanded by clicking the "operation order" button. Green check marks would appear beside those steps which had been completed correctly.

Step 1. Identify faulty load break elbow

Step 2. Test de-energized and ground cable inside of fuse cabinet

Step 3. Test de-energized and bump ground cable inside of dead-front terminator

Step 4. Create EPZ in structure with faulty elbow

Step 5. Replace the faulty elbow

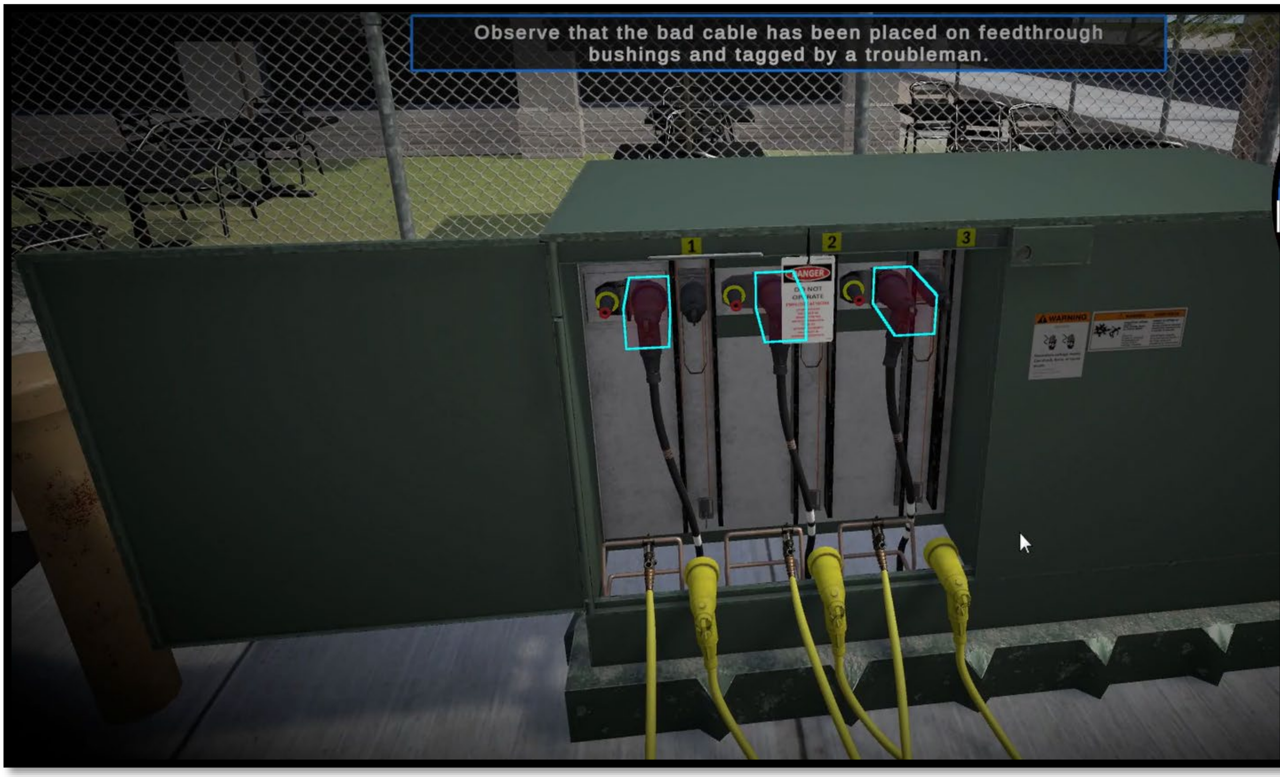
Step 6. Re-energize the fuse cabinet

Step 7. Restore service inside the dead-front terminator

Use Case/Scenario 2 – Replacing Cable Run

In this scenario, the participant's replaced a faulty run of cable, shown in Figure 3. It goes from an above ground structure to a handhole using EPZ work methods. The work began at the switch cabinet where the faulty cable originated. All switching, tagging and holds had been completed. The primary focus was to establish and maintain an EPZ. Operation order below list the steps which were required for this scenario.

Figure 3: Faulty Run of Cable



Step 1. Identify faulty run of cable

Step 2. Test de-energized and ground cable inside of switch cabinet

Step 3. Test de-energized and ground cable inside of handhole

Step 4. Create EPZ in handhole

Step 5. Descend into handhole

Step 6. Replace faulty cable

Step 7. Re-energize the switch cabinet

Step 8. Re-energize the handhole

Use Case/Scenario 3 – Replacing a T Connector

In this scenario, the participants replaced a failed 600-amp T Connector, shown in Figure 4. It was located inside of a handhole. The participants had to work with both jacketed and unjacketed cable. Using EPZ work methods the participant's performed work within this structure, another handhole and a switch cabinet. All switching, tagging and holds had been completed. The focus was to establish and maintain an EPZ. Operation order below lists below the steps which are required for this scenario.

Figure 4: Failed 600-AMP T Connector

Step 1. Identify T to be replaced

Step 2. Test de-energized and ground cable inside of switch cabinet

Step 3. Test de-energized and ground cable inside of handhole

Step 4. Test de-energized and ground cable inside of handhole with T to be replaced

Step 5. Create EPZ in handhole

Step 6. Descend into handhole

Step 7. Perform T body replacement

Step 8. Complete work at east side handhole

Step 9. Complete work at west side handhole

Step 10. Restore service inside switch cabinet

Use Case/Scenario 4 – Live Front to Dead Front Equipment Replacement

In this scenario, the participants replaced a live front terminator containing both jacketed and unjacketed cable, to a dead front terminator. A picture of the live front equipment that needed to be replaced, shown in Figure 5.

Figure 5: Live Front Equipment to be replaced

Using EPZ work methods the Participants performed work within the terminator and two handhole structures. All switching, tagging and holds had been completed. The primary focus was to establish and maintain an EPZ. Operation order below lists the steps which were required for the scenario.

Step 1. Identify Live Front Equipment

Step 2. Test de-energized and ground cable inside of east side handhole

Step 3. Test de-energized and ground cable inside of west side handhole

Step 4. Test de-energized and ground cables inside of live front terminator

Step 5. Remove cabinet and create EPZ

Step 6. Splice cable tails

Step 7. Install dead-front cabinet

Step 8. Prepare dead front terminator for energization

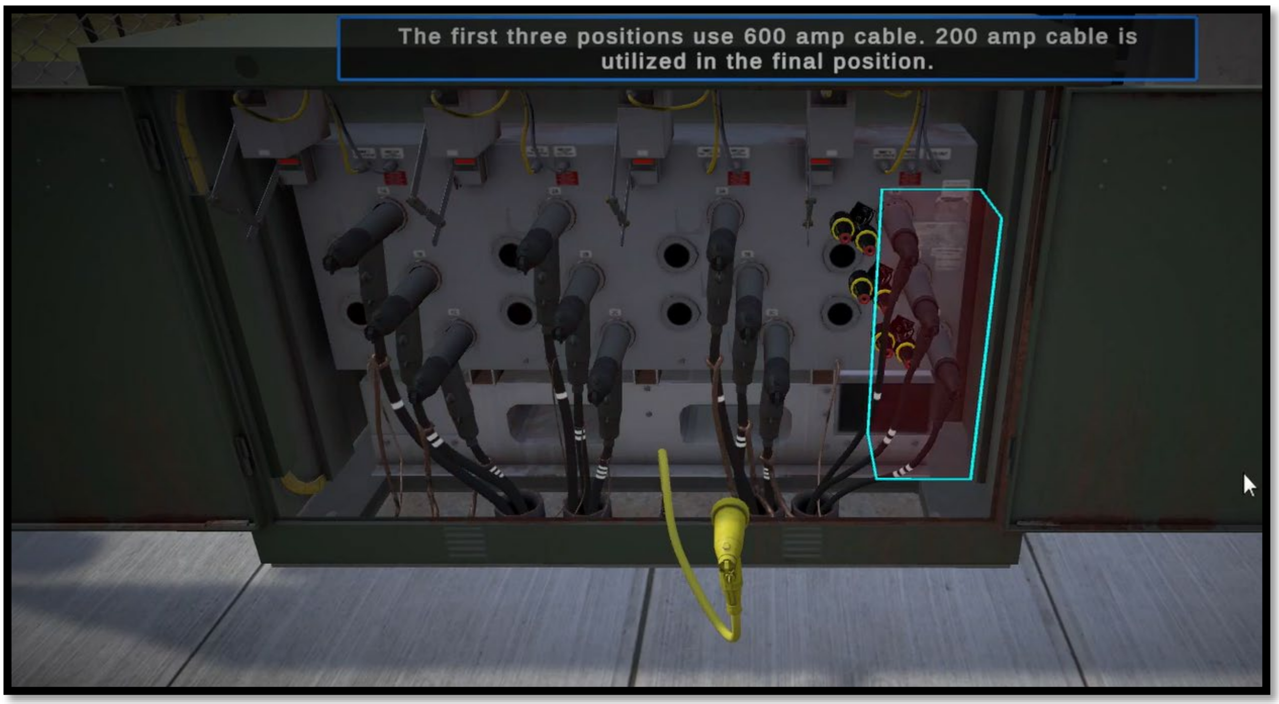
Step 9. Complete work at west side handhole

Step 10. Complete work at east side handhole and restore service

Use Case/Scenario 5 – Changing a Switch

In this scenario, the participant's changed out a four-way pad mounted switch, shown in Figure 6, using EPZ work methods. All switching, tagging, and holds had been completed. The primary focus was to establish and maintain an EPZ. Operation order below lists the steps which were required for this scenario.

Figure 6: Four-way switch



Step 1. Identify four-way switch

Step 2. Test de-energized and ground cable inside of 600-amp switch

Step 3. Test de-energized and ground cable inside of east side handhole

Step 4. Test de-energized and ground cable inside of west side handhole

Step 5. Test de-energized and ground cable inside of dead-front terminator

Step 6. Test and bump ground all positions inside four-way switch

Step 7. Create EPZ around four-way switch

Step 8. Pull away T bodies

Step 9. Pull out feedthrough bushings

Step 10. Change switch

Step 11. Install feedthrough bushings

Step 12. Install T bodies

Step 13. Take 200-amp elbows off feedthroughs

Step 14. Complete work at four-way switch

Step 15. Prepare dead front terminator for energization

Step 16. Remove grounds at west side handhole

Step 17. Remove grounds at east side handhole and restore service at 600-amp switch

5.2.7 Data Acquisition

The participants were asked to provide their feedback about the new training method using VR as compared to traditional training. The participants feedback included measurable success factors such as level of engagement, ease of use, clarity of training content, participant's confidence level, and overall training effectiveness along with safety and risk were assessed. The participant survey template can be found in Appendix A.

All the survey success factors were measured and assessed on a scale of 1 to 5 with the highest success rating being 5, significantly increased and the lowest rating being 1, significantly reduced. The survey scale ratings were as follows:

<u>Participant Survey Rating Scale</u>

1 - Significantly Reduced

2 - Visibly Reduced

3 - No Change

4 - Visibly Increased

5 - Significantly Increased

5.3 Data Analysis

A total of seven success factors were assessed to evaluate and compare VR training with Traditional method. Data analysis results from participant surveys of the VR training are listed in Table 3. A copy of the survey used to collect the data can be found in Appendix A.

Table 3: Data Results

Success Factor Number	Success Factor Description	VR Training Vs Traditional Training
1	Information Retention	Significantly Increased
2	Situational Awareness	Significantly Increased
3	Level of engagement	Significantly Increased
4	Ease of use	Visibly Increased
5	Content Clarity	Significantly Increased
6	Level of confidence	Visibly Increased
7	Training effectiveness	Significantly Increased

6.0 Project Results

Assessment of VR Training over traditional method displayed improvements in multiple areas, including but not limited to, information retention, situational awareness, ease of use, level of engagement, clarity of training content, and level of confidence. The VR training was shown to be an improved training tool due to its overall effectiveness.

6.1 Results Discussion

The demonstration of VR training as reflected in Table 3 above showed improvement in every success factor criterion.

Overall, the system demonstrated an effective and improved training method over traditional method that utilized only presentations and training videos. As a result, the participants showed an increased level of confidence making VR a very effective training tool.

The adoption and learning curve for trainees that are unfamiliar or inexperienced with this type of technology may take additional resources to implement.

6.2 Updated Benefits Analysis

The Module 2 demonstration results successfully verified the initial benefits identified, including effectiveness of VR technology in improving safety of personnel during training and while performing work in the field. Additional benefits include reduced operation cost, an increase in the number of trained personnel available, reduced operation cost, improved customer experience, reduced training duration, and an increase in worker effectiveness attributable to the training.

The updated benefits analysis and value proposition are as follows:

Safety to SDG&E's Personnel

- With the VR simulator, SDG&E would be able to provide initial and refresher training to more employees on the proper procedures of doing PPG/EPZ on distribution UG.

Improved Customer Experience

- With the VR training, SDG&E would be able to restore power to the customer more quickly.

Risk Reduction

- The VR training would help protect employees from hazardous potentials caused by line induction and/or non-utility generation sites (e.g., photovoltaic systems, wind turbines).

Increased number of trained personnel available

- Increased number of field workers with readiness for safe work practices.

Reduced Cost

- The PPG/EPZ procedures allow the work to be performed in a localized environment and thereby reduces power outage duration, due to the increased skill level of employees. The reduced outage duration helps SDG&E reduce the cost of system operations.

Increase in worker effectiveness attributable to the training

- The VR training can be a more effective tool in terms of clarity and use of the content, making it more effective compared to traditional method using presentations and videos only.

Reduced Training Duration

- Initial studies indicate that once the training is fully developed, and the training process becomes more efficient, the participants could take less time to complete the training. This kind of training is more participatory and immersive, and is expected to provoke more conversations, which creates a better learning environment and fosters a diversity of discussion across the student cohort groups.

-

Improved Customer Experience

- The reduced outages not only help SDG&E with cost reduction of system operations, but also improve the customer experience due to superior reliability.

6.3 Commercialization Cost Estimates

To estimate commercialization cost for this type of VR training program, a planning phase is needed to better understand the commercialization process and its requirements.

There is some upfront cost for VR equipment and purchase or licensing of software, but the largest expense is likely to come from additional staff and trainers necessary to implement a sophisticated VR training platform and program. The associated VR LMS does not need to be integrated into other information technology systems and can be a standalone option; this can ease cost burdens and complications of roll out.

7.0 Findings

The demonstration was successful in all the established metrics. It determined that VR tools can be utilized to train utility industry personnel on safety related issues, such as EPZ and grounding techniques associated with current construction work practices. The tools have the ability to provide rich contextual information within the delivery of the training.

The VR training is a step closer to hands-on field experience, without the associated risks, enabling the trainee to learn the procedures in a safer environment. As a result, the participants showed an increased level of confidence, making VR training a more effective approach.

Along with the confirmed success measures for this demonstration, a few challenges were noted. Those include an initial increase in training costs for the equipment and software and the necessary personnel to develop the new training requirements, employee learning curves to be able to adapt to the new technology, and the impacts for employees with little or no previous experience with VR or similar technologies.

8.0 Conclusions

The VR training successfully performed desired functions. It showed significant improvement relative to all the criteria tested against traditional training approaches. While the project did identify some initial challenges and more evaluation towards commercialization should be done to understand additional training scenarios and definitive costs, these challenges could be addressed and may phase out during commercial adoption of this VR approach.

9.0 Tech Transfer Plan

9.1 Project Result Dissemination

The primary mechanism for dissemination of the project results is this comprehensive final report, which is filed with CPUC and posted on SDG&E's public website. Interim results have been shared in EPIC symposium, prompting education and continued interest in using a VR as a training medium. Results from this deployment can also be shared via presentations at relevant industry conferences.

9.2 Transition for Commercial Use

Recommended key next steps because of the learnings from this demonstration that could assist the transition of such a technology to a commercial use are outlined below.

Step 1 - Expansion of Training Content: Before the VR training module is commercially adopted, it is recommended to expand the VR training content library to more complex scenarios from the distribution disciplines.

Step 2 – Testing and Analysis: Perform extensive testing to identify gaps and weaknesses in the VR training experience and use the results to improve clarity and completeness of the training material.

Step 3 – Long Term Impact: The VR training program needs to be studied for its long-term impacts and benefits which could be used to make required adjustments to make it a more comprehensive training program.

Step 4 – Develop VR Training Library: Make required adjustments to the training material based on the additional testing and study results before developing a complete VR training course covering every scenario for a comprehensive training program.

Step 5 – Program Storage: Procure cyber infrastructure needed to upload the program on a secure server or locally for easy access.

Step 6 – Hardware Procurement: Planning and management of procurement, installation, and maintenance of required hardware, including periodical tech transfer as equipment achieves end of useful service life.

Step 7 – Maintenance and Hardware Upgrade Policy: Develop policies for maintenance and hardware upgrade including, but not limited to, source of procurement, hardware specification, maintenance schedule, and upgrade criteria.

Step 8 – Develop Training and Testing Policy: A clear training policy includes training content, goals, criteria, duration, and testing policy. This also includes areas of testing like situational awareness and, repair process.

Step 9 – Develop Learning Management System (LMS): A LMS is needed to help record data over a specific time. This will be used to track and analyze the effectiveness of the training, gaps in the training curriculum, number of trained personnel, refresher course due dates, and other identifiable measures used to further improve the system.

10.0 Recommendations

VR can be a very successful approach to training and provides a complex engaging environment to enhance and refresh utility personnel on safety related issues, such as EPZ and grounding techniques associated with current construction work practices.

This EPIC project has ended. It is recommended that follow-up work be pursued to establish a path to commercialization. The appropriate internal SDG&E stakeholder group should be given the lead responsibility for managing the commercialization process.

Logical "next steps" towards commercialization would include:

- Setting up a permanent resource team to accomplish commercialization
- Arranging funds for commercial adoption and on-going maintenance of commercial operations
- Developing a commercialization plan

11.0 Appendix A – Sample Survey

EPIC 3 Project 4 – Safety Training Simulators with Augmented Visualization

Module 2 – Virtual Reality Training Simulator for Personal Protective Grounding/Equal Potential Zones on the Electric Distribution Underground System

Training Effectiveness Survey

1. What is your Name?

    ____

2. What is your Age?

    ☐ <30 Years ☐ 30-40 years
    ☐ 41-50 Years ☐ >50 Years

3. What is your Gender?

    ☐ Male ☐ Female
    ☐ Custom (Please Specify) ☐ Prefer not to say

4. How many years of experience do you have with electrical systems?

    ☐ <5 Years ☐ 6-10 Year
    ☐ 10-15 Years ☐ >15 Years

5. How familiar are you with Virtual Reality Training?

    ☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5
    Not Familiar Very Familiar

6. How well did this Virtual Reality simulation replicate a real field scenario?

    ☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5
    Disappointing Exceptional

7. How easy to use was this Virtual Reality training system?

    ☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5
    Disappointing Exceptional

8. How relevant was the training material?

☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5

Disappointing Exceptional

9. How well prepared do you feel for a real field scenario after this Virtual Reality training?

☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5

Disappointing Exceptional

10. How effective/helpful was the Virtual Reality training with information retention?

☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5

Disappointing Exceptional

11. How engaging was the Virtual Reality training compared to traditional video training?

☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5

Disappointing Exceptional

12. How would you rate the overall effectiveness of the Virtual Reality Training on a scale of 1 to 5?

☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5

Disappointing Exceptional

13. Do you have increased situational awareness in terms of safety after Virtual Reality training on a scale of 1 to 5?

☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5

None Significantly more

14. How long did you take to complete the training (in hours)?

☐ 1hr ☐ 2hr ☐ 3hr ☐ 4hr ☐ 5hr

15. Rate the following on 1 to 5 scale where "1" is Disappointing and "5" is Exceptional:

a. Training	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
b. Supervision	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
c. Guidance	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
d. Tools	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5

16. Check top three things that you liked about the Virtual Reality training:

☐ Instruction Clarity

☐ Ease of use

☐ Better Understanding

- ◻ Higher content retention
- ◻ Reduced training time

17. Which training method would you prefer – Traditional Video training or Virtual Reality Training?
    - ◻ Virtual Reality Training
    - ◻ Traditional Video Training

18. What was the most difficult part of Virtual Reality training?

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19. What was your favorite part of Virtual Reality training?

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20. What is one thing that can be improved?

EPIC Final Report

Program	Electric Program Investment Charge (EPIC)
Administrator	San Diego Gas & Electric Company
Project Number	EPIC-3, Project 5
Project Name	Unmanned Aircraft Systems (UAS) With Advanced Image Processing for Electric Utility Inspection and Operations
Date	December 20, 2021

Attribution

This comprehensive final report documents work done in Electric Program Investment Charge (EPIC) 3, Project 5. The project team that contributed to the project definition, execution, and reporting included the following individuals:

San Diego Gas and Electric (SDG&E)

- Asaro, Christine
- Deering, Teena
- Fitzgerald, Curtis
- Forgette, Dan
- Goodman, Frank
- Lindsay, Gina
- Perkins, Scott
- Ubinas, Hector
- Veihl, Richie

Executive Summary

SDG&E's Project 5, Unmanned Aircraft Systems (UAS) with Advanced Image Processing for Electric Utility Inspection and Operations, under the third triennial cycle of the Electric Program Investment Charge (EPIC-3), has been completed. The objective of this project was to define, demonstrate, and evaluate concepts for instrumentation and monitoring of the power system equipment using enhanced imaging and sensor technology on UAS.

UAS provides a unique opportunity for SDG&E to obtain, disseminate and use aerial sensor data that provides benefits such as cost savings to its ratepayers and lower physical risks to SDG&E personnel while increasing public safety.

The project focus areas were to demonstrate practical applications of UAS and to evaluate platforms that could integrate UAS applications with existing and future SDG&E infrastructure, software applications and legacy data sets with the ability to ingest, store, analyze and report on SDG&E assets derived from collected data.

The project examined which sensors best supply a necessary file format and metadata to deliver data for ingestion and processing within a future artificial intelligence (AI) platform. For assessment of infrastructure (i.e., equipment, lines, and structures), the project sought to determine the compatible sensors needed for collecting data, the AI platform, and the acceptable file types.

At the early stage of the project work, the project team held a series of meetings and fact-finding workshops with various stakeholders from the operation and engineering departments within SDG&E. The early research gave the project group insight into what technology to evaluate to improve the current work methods regarding time savings, efficiencies, innovation, and safety.

The project demonstrated seven use cases with the following outcomes:

- Aerial Telepresence: Issues were identified that may be resolved with the new 5G network.
- Public Safety Power Shutoff (PSPS)/Wildfire Mitigation Program (WMP): Adopted for commercial use; seven hard-to-access areas were identified for PSPS patrols using UAS.
- Coronal Camera: Licensed thermographers trained on UAS with integrated coronal camera.
- Tethering: Successful demonstration of use case; adopted for commercial use.
- Sense and Avoid: Two units with sense and avoidance of thin power lines and guy wires as well as confined space indoor inspection. Both use cases were determined as high-value and are now in commercial use.
- Line Pulling: Determined a high value use case and is in commercial use.
- Vertical Take Off and Landing (VTOL) - Fixed Wing/Beyond Visual Line of Sight (BVLOS): Due to the difficulty with launch and land procedures, this unit was not purchased, and the use case will not be pursued.

This project successfully demonstrated the value proposition for UAS and the newly mounted sensors that were tested. Based on the findings and results in the demonstrations, it was determined that the

use cases for aerial telepresence and vertical take-off and landing are not yet ready for commercial adoption in SDG&E's applications. The remaining use cases however, including PSPS/WMP, coronal camera, sense and avoid, confined space indoor inspections and line pulling, proved the UAS could perform the tasks intended, and those technologies are now in commercial use at SDG&E. This EPIC project is now completed. Given the successes of this EPIC project, it is recommended that additional work be done to further evaluate and expand use of these UAS technologies and use cases to identify others that can be used commercially in future utility system operations. It is also recommended that the appropriate internal stakeholder group within SDG&E be identified to lead the commercialization and operational use of the technologies that were demonstrated in the EPIC project.

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List of Acronyms

Acronym	Definition
4D	Four Dimensional
AGL	Above Ground Level
AI	Artificial Intelligence
ASD	Aviation Services Department
BVLOS	Beyond Visual Line of Sight
CNF	Cleveland National Forest
COA	Certificate of Authorization
CPUC	California Public Utilities Commission
DAC	Disadvantaged Communities
DER	Distributed Energy Resources
DIAR	Drone Investigative and Repair
EDE	Electric Distribution Engineering
EOC	Emergency Operations Center
EPIC	Electric Program Investment Charge
ERO	Electric Regional Operations
FAA	Federal Aviation Administration
FiRM	Fire Risk Mitigation
FPV	First Person View
FOB	Flight Operations Base
GIS	Geographic Information System
IOU	Investor-Owned Utility
IPP	Integration Pilot Program
IR	Infrared
ISV	Incident Support Vehicle
KMZ	Keyhole Markup Language
ME	Mountain Empire

Acronym	Definition
NOTAM	Notice To Airmen
NTR	None to Report
O&E	Operations & Engineering
PSPS	Public Safety Power Shutoff
QAQC	Quality Assurance Quality Control
QEW	Qualified Electric Worker
RC	Remote Control
RFP	Request for Proposal
RFW	Red Flag Warning
RPIC	Remote Pilot in Command
SD	Secure Digital
SDG&E	San Diego Gas and Electric Company
SOCRE	South Orange County Reliability Enhancement
TCM	Transmission, Construction and Maintenance
TFR	Temporary Flight Restriction
UAS	Unmanned Aircraft System
UV	Ultraviolet
VTOL	Vertical Take Off and Landing
WMP	Wildfire Mitigation Program

1.0 Introduction and Objectives

This report documents the work performed in SDG&E's Project 5, Unmanned Aircraft Systems (UAS) with Advanced Image Processing for Electric Utility Inspection and Operations, under the third triennial cycle of the Electric Program Investment Charge (EPIC-3). The objective of this project was to define, demonstrate, and evaluate concepts for instrumentation and monitoring of the power system equipment using enhanced imaging and sensor technology on UAS.

The focus of EPIC-3, Project 5 was to demonstrate new applications of UAS, including those with enhanced image processing capabilities for electric inspection and operations. This project sought to expand on the extensive work previously conducted by SDG&E on UAS applications resulting in the analysis of high-quality images and data from UAS in aiding time-sensitive decisions in its operations. This project sought to explore the capabilities of UAS to assist in asset aging issues, vegetation management, support for power system operations and wildfire mitigation.

The combination of UAS monitoring and analysis with utility inspection capabilities is designed to improve service reliability, reduce costs, and increase employee and public safety. Specific benefit targets include early identification of failing assets, avoidance of catastrophic events, data for future predictive analytics, and improved engineering practices. Demonstrated uses of UAS in the utility space have the potential to benefit customers by avoiding more costly solutions, thereby lowering operating costs and ultimately reducing ratepayer costs.

The pre-commercial demonstrations documented in this report include the following use cases:

1) Aerial Telepresence
2) Night Flights/Public Safety Power Shutoff (PSPS)/Wildfire Mitigation Program (WMP)
3) Corona Camera
4) Tethering
5) Sense and Avoid Technology/Indoor Confined Space Inspections
6) Line Pulling
7) Vertical Take Off and Landing – Fixed Wing/Beyond Visual Line of Sight (BVLOS)

The project sought to determine the best sensor technologies to meet metadata (latitude/longitude, time/date stamps, position of sensor, position of aircraft) and file format requirements for ingestion and processing within a future intelligence platform.

The project generated valuable lessons learned when traditional methods of assessment are replaced or enhanced by UAS, as demonstrated through execution of the use cases mentioned above. These lessons and other project results have been distributed to the broader utility community and other stakeholders through this report filed with the California Public Utilities Commission (CPUC) and released on SDG&E's EPIC public website. The project endeavored to determine the potential of UAS for increasing reliability, safety, and cost efficiency in power system operations.

2.0 Issues and Policies Addressed

Technology advancements in monitoring, measurement and inspection help reduce labor-intensive efforts to maintain and operate the power system infrastructure. Asset monitoring and inspection using UAS has emerged as a possible solution for remote asset inspections. An operator of a UAS can assess conditions through a live high-definition feed or still images taken during flight. The technology offers a safer, less time consuming and less labor-intensive approach than traditional methods. Traditional methods including manned aircraft, are expensive and require specific locations for safe take-offs and landings. UAS can reach remote areas at a lower cost and can be operated in complex terrains that ensure flight safety without compromising data accuracy.

Additionally, with natural disasters increasing, the impact on aging critical energy infrastructure becomes more severe. UAS for preventative and reactive storm response and mitigation has proven a useful and verifiable tool. UAS improves worker safety by providing remote visualization to affected areas without exposing crews to potentially dangerous conditions.

3.0 Project Focus

The focus of this project was to demonstrate practical applications of UAS that have strong implications for worker safety, system reliability, data collection and storage, and improved decision making in operations. The project followed a simple formula to capture, process, analyze, and share information using UAS.

The project examined which sensors best supply a necessary file format and metadata to deliver data for ingestion and processing within a future artificial intelligence (AI) platform. For assessment of infrastructure (i.e., equipment, lines, and structures), within a specific environment with autonomous features that can be leveraged, the project sought to determine the compatible sensors needed for collecting data, the AI platform, and the acceptable file types.

Examples of activities included in the project were:

- Demonstration and evaluation of multi-spectral sensors for high-definition imagery, ultraviolet (UV)/reflectivity, and infrared for detailed inspections.
- Use of UAS to identify various levels of corrosion on distribution equipment along coastal areas.
- Analysis to categorize corrosion levels to identify potential risks and associated operational plans.
- Demonstration and evaluation of capabilities of advanced imaging enabled UAS for disaster response and re-energization of patrols.
- Demonstration of UAS capabilities to support vegetation management and wildfire mitigation.

4.0 Project Scope Summary

This project scope was to define, demonstrate and evaluate concepts for instrumentation and monitoring of the power system equipment using UAS imaging and sensor technology.

To perform the use case demonstrations, a trained remote pilot in command (RPIC) conducted multiple flights for each use case in the field with the appropriate SDG&E department. The RPIC recorded the results providing raw data and analysis of each pre-commercial concept demonstrated.

Primary outcomes include:

- Demonstrations of the defined use cases using various UAS technologies comparing to traditional methods.
- Identification of lessons learned for distribution to the wider utility community.
- Recommendations for transitioning use cases to commercial adoption.
- Support to SDG&E in determining costs and benefits for adoption into commercial practice.
- A comprehensive final project report for public dissemination of the project approach, findings, and recommendations.

5.0 Project Approach

The project approach was comprised of the following tasks and sub-tasks.

Task 1 - Initiation of Project Plan

Task 1a – Identification of Stakeholders and Formation of Stakeholder Steering Committee, Technical Advisory Committee, and Project Team

The following steps were taken to identify and engage the key stakeholders in this project.

Objective: This task objective was to identify prospective users and other internal clients impacted by the project results and acquire internal stakeholder steering committee and advisory committee representation from these groups. The goal was to identify stakeholders with the necessary skill sets and technical expertise to help assess the strategic value of the work; and assist the inter-group coordination and staffing required to perform the project work. The steering committee was chaired by the Champion Director for the project and was the governing body.

Approach: The first action was the identification of key stakeholders and prospective project team members including members of Aviation Services Department (ASD), Electric Distribution Engineering (EDE), Distributed Energy Resources (DER), Fire Risk Mitigation (FiRM), Fire Science & Coordination, Transmission, Construction and Maintenance (TCM) and District Operations and Engineering (O&E). Also completed during this task was the establishment of the Stakeholder Steering Committee and Technical Advisory Committee and presentation of progress reports to stakeholders.

Task 1b - Project Kick-off and Development of Project Plan

Objective: The focus of this sub-task was to complete the project kick-off, develop the project plan, identify resource requirements, and further develop the internal project team.

Approach: Working with the stakeholders identified in Task 1.a., the following steps were taken to identify additional internal staff resources and any contractors required to undertake the actual demonstration project work.

The focus of this project was identified during a project strategy session in Fall 2018. Based on stakeholder input, the team proceeded to write a project plan around the chosen focus. During the project planning phase, the writing team compiled a detailed description of the benefits estimate, technical scope, deliverables, resource requirements, expected budget and project schedule.

Weekly recurring meetings with the project plan writing team were scheduled to lay the groundwork for this project. As part of the project plan writing effort, the core project team was assembled based on task categories identified. The stakeholder steering committee secured the necessary project team members and the requirements for contractors were assessed and later procured using established company procurement business practices.

Task 2 – Development of Project Requirements

Task 2a. - Fact Finding

Objective: The goal of this task was to explore the availability of existing UAS technology and identify the most suitable products for the selected use cases.

Approach: Initial steps in this task included the investigation of UAS solutions available for purchase or contract, followed by evaluation of technical capabilities of industry products from potential vendors through site visits and attending industry conferences as needed. Examining past commercial projects at SDG&E, a review was completed to determine which sensors would deliver the best results for data ingestion and processing. After the project plan and scenario tasks were selected, vendor/contractor solicitations were planned to occur further downstream in the project schedule.

Internal teams investigated UAS solutions and identified vendor/contractor candidates. Upon identifying potential candidates, coordination of meetings to support the development of bidders lists and other procurement activities was performed. The following SDG&E groups were involved in these investigations:

- ASD – Aviation Services Department
- FiRM – Fire Risk Mitigation
- DER – Distributed Energy Resources
- EDE – Electric Distribution Engineering
- Fire Science & Coordination
- TCM – Transmission, Construction and Maintenance
- O&E – Operations & Engineering

Task 2.b. – Baselining Current Condition and Practices

Objective: The focus of this task was to determine the existing applications, conditions, and best practices for UAS within the utility industry.

Approach: This task consisted of a review of existing SDG&E UAS practices, including leveraging of innovative technology to safely inspect power lines and gas pipelines in environments that are off-limits to helicopters or difficult to access by road or other means.

For example, during daylight inspections, UAS can be used to:

- Locate the cause of power outages
- Inspect power and gas lines
- Access infrastructure in remote areas that are difficult to access by ground crews or helicopters
- Improve situational awareness during emergencies through monitoring of fires
- Achieve cost savings, noise reductions and environmental protection by avoiding the use of helicopters and other heavy machinery
- Support vegetation management and wildfire risk mitigation
- Capture images of fire breaks

Task 3 – Development of Funding Base and Collaborative Funding and In-Kind Services

Objective: The purpose of this task was to seek opportunities for partnering and cost sharing to allow expansion of work potential for this project.

Approach: This task included the inquiry into leveraging collaborative funding opportunities with SDG&E's FiRM department to piggyback on their commercial activities for centralized data collection to perform data processing and analytics. Prospective collaboration with other investor-owned utilities (IOU), the Federal Aviation Administration (FAA), Integration Pilot Program (IPP) and other potential partners was also explored. In competitive procurement of the contractor and vendor resources for the project, dollar cost sharing and in-kind services (such as equipment loans) were requested.

Task 4 – Contractor Procurement:

Objective: This task focused on the competitive procurement of qualified contractors.

Approach: Established SDG&E procurement business practices were used to select successful vendors and negotiate contracts for equipment procurement and support for task areas that could not be performed solely by SDG&E staff. Both the internal project team and the project stakeholder steering committee were engaged in the decision processes. Working with Supply Management, the vendors were soul sourced as they had uniquely qualifying systems/services. Following the selection of vendors, the vendor list and capabilities were reviewed with the stakeholder steering committee.

Task 5 – Site Selection and Procurement of UAS Equipment, Hardware, Software, and Licensing

Objective: This task sought to select a preferred and alternate site for flights to test the best sensors in all environments.

Approach: The sensors require massive data streams and a central repository. When procuring equipment, SDG&E rented, purchased, or used from available inventory.

The repository requirements were a separate commercial project at SDG&E and included hardware, software, electric power, climate control, and other site requirements.

Requirements for site selections included obtaining a certificate of authorization (COA) when flying beyond visual line of sight and in restricted airspace. A large, outdoor space that was isolated from the public was required for flight testing.

Task 6 – Preparation of Use Cases and Test Plan

Objective: UAS use cases were prepared to define the demonstration process for the project.

Approach: A description of use cases was developed with sufficient detail to fully understand the nature of the task. Metrics to define completion of the demonstration were established as well as the determination of data taking requirements to support updating the initial benefits estimate. Steps to finalize use cases and define metrics for demonstration and preparation of a test plan were included in this task. The test plan informed sequential execution of the use cases at the selected sites and recording the raw data. Formal project reviews were conducted with stakeholders.

Task 7 – Preparation for Testing

Objective: The objectives of this task were the development of the test set-up for the demonstration work and completion of the supporting modeling work.

Approach: This task began with preparation of the test set up for running the demonstrations at the selected sites and running any preliminary modeling needed to maximize the value of the use case runs. The team identified what data would be recorded and ensured the correct infrastructure was ready to ingest the data. Additional actions taken during this task included assuring the right data was collected for updates to the benefit analysis and that all the equipment and software required was ready to meet scheduling requirements of the demonstrations. Accurate evaluation of the overall time, effort, cost, and effectiveness for each use case was achieved during this task.

While conducting this task, a Red Flag Warning (RFW) was an added procedure to UAS operations that dictated an on-call schedule when issued. As Public Safety Power Shutoff (PSPS) events can be identified at least three days before a weather event, RPICs will be on standby two days prior to the event to support potential Pre-PSPS Patrols. After the RFW has expired, the RPICs will standby at the district locations for easy deployment. The expected hours of support are from sunup to sundown. During the PSPS UAS flight, the UAS crews support inspection of overhead power lines to check for debris and equipment damage prior to re-energizing lines. A qualified line checker is on sight and reviewing the live stream data using the second UAS remote.

Task 8 - Perform the Pre-Commercial Demonstration

Objective: The goals of this task were to execute the pre-commercial demonstrations and generate data for use in subsequent tasks.

Approach: The internal SDG&E team lead the effort in setting up equipment, running tests in concurrence with the use cases, and compiling the data and test results for use in the data analysis task that followed.

Task 9 – Analysis of Results

Objective: This objective of this task was to analyze the data and results ensuing from the demonstrations to support the development of key findings, conclusions, and recommendations for the project.

Approach: The project team reviewed all data to determine which use cases were successful in providing innovative solutions to enhance UAS operations. The following considerations were included in this process:

- Which sensors contributed significant value and should be adopted for commercial use?
- How should the sensors be used?
- What value proposition is associated with the innovative solutions relative to the original baseline of current practice?

The analysis examined how the metrics aligned with the initial benefits estimate. Additional considerations during this task included:

- Were there additional benefit areas that were identified?
- Was the benefit stream greater or less than the original estimate for the benefit areas that were identified at the start of the project?
- What were the key lessons learned and other key findings in the demonstrations?
- What key conclusions and recommendations were derived from the analysis?
- Was the demonstration information complete?
- Were there any gaps that could be filled by running a few more tests, if funds were still available?

Task 10 – Development of Conclusions and Recommendations

Objective: This focus of this task was to develop the key findings, conclusions, and recommendations for the project.

Approach: The project team applied the results of the data analysis task to update the initial benefits analysis and formulate key findings, conclusions, and recommendations for the project. The project team confirmed success or failure of each use case demonstrated and made recommendations for which use cases should be pursued commercially, defining next steps.

Task 11 – Preparation and Implementation of Tech Transfer Plan

Objective: This task focused on the development and implementation of a technology transfer plan.

Approach: The team set out to develop a technology transfer plan to identify a process for transferring project results into practical use at SDG&E and other stakeholder sites. The plan indicates which tech transfer activities took place during the demonstration work, which will be completed at the close of the project, and which will be completed by the stakeholders after the project ends. Example activities are release of this comprehensive final report, preparation of technical papers for presentation at conferences and in journals, participation in CPUC-required events, and a final briefing to the internal SDG&E stakeholders.

Task 12 - Disposition Plan for Equipment and Software

Objective: The focus of this task was to define and implement a disposition plan for equipment and software used in the project.

Approach: Equipment not owned by SDG&E was returned to the owners. Equipment and software owned or licensed by SDG&E was either transferred to the designated internal stakeholder or remained within ASD for potential use as needed. An inventory sheet was created of all UAS, and sensors purchased for asset tracking purposes.

5.1 Baseline Studies/Fact Finding

5.1.1 Initial Benefit Estimate and Value Proposition

The initial benefit areas focused on the following core areas:

1) Improved sensor technologies and modern methods of data collection will greatly improve worker safety and reduce potential for wildfires, specifically in disadvantaged and low-income communities
2) Increased power system reliability, safety, and cost efficiencies – improved operations and higher cost savings
3) Advanced imaging provides more efficient disaster response times, reporting, and re-energization of patrols after a site is deemed all-clear
4) Improved long-term planning – ability to determine the status of scenarios as-is versus how they should be
5) Supports and increases staff efficiencies of seven departments including Aviation Services Department (ASD); Electric Distribution Engineering (EDE); Distributed Energy Resources (DER); Fire Risk Mitigation (FiRM), Fire Science and Coordination; Transmission, Construction & Maintenance (TCM); and District Operations & Engineering (O&E)

All the use cases demonstrated in the project reduce safety risks in hard-to-reach areas within the SDG&E service territory as their implementation replaces the requirement for manned aircraft and/or field deployments. Benefit estimates and value proposition specific to each use case are provided below.

Aerial Telepresence

The potential value of this use case arises from the live stream video capability with no latency of information. Aerial telepresence offers situational awareness during fire, weather, and other emergency events via live video stream to anyone with the web link. The ability to control the UAS via desktop controls ensures correct data is collected and allows for remote assessments, reducing costs, and eliminating potential for safety hazards.

Public Safety Power Shutoff (PSPS)/Wildfire Mitigation Program (WMP)

This use case provides the potential to assist in the patrol of pre- and post-PSPS in small hard-to-reach foot patrol segments of the service territory. This helps to reduce duration of assessments and allows photo/video feeds from an aerial perspective capturing metadata (Latitude/Longitude, time captured, etc.) to update records when needed. UAS-assisted patrols may also result in reduced time of de-energization contributing to cost and safety efficiencies.

Corona Camera

The use of the hand-held device integrated within the DJI M600 UAS platform can result in reduction of time driving/walking to each tower to capture the four angles required during assessment. The four angles capture the connection points where dirt/damage can be seen only by using the corona camera sensor. Using this tool can help reduce duration of assessments as well as safety risks as the UAS can fly to many structures from one remote location.

Tethering

Wire tether eliminates the battery replacement downtime and associated video disturbance, providing live-streaming capabilities for extended periods over a network. This system can provide constant UAS aerial footage as it is tethered to a power source. The UAS has infra-red (IR) and zoom capabilities as well as the ability to live stream data during an emergency. The benefit of using this system is the potential elimination of employee deployment into the field to evaluate conditions during an event.

Sense and Avoid Technology

Utilizing the sense and avoid technology can reduce mishaps during flight in tight spaces as the obstacle avoidance system has proven successful. This is the only unit to date that can sense and avoid thin overhead lines and tree branches known to cause UAS mishaps. The benefit of using this system lies in its ability to fly in areas that many other UAS cannot, allowing for closer inspection and reducing risk of striking obstacles.

For indoor applications, the UAS can save time and inspection costs, as it can complete an inspection within minutes/hours versus days/weeks compared to traditional practices. As an example, one current process requires the construction of scaffolding within a confined space to allow the inspector to access an area required for inspection. The inspection area is 300 feet in height and could cost the company up to $38K annually overall to build the scaffolding required to complete annual inspections. The scaffolding construction process alone takes days with the added labor hours to complete the inspection. During the test case, an actual inspection was tested and successfully completed in one and a half hours. Utilizing this UAS for required and emergency inspections will help with efficiency, cost savings and the overall safety of employees, as the requirement for boots on the ground inspections is removed. This UAS is the first to successfully demonstrate the ability to fly within utility confined spaces to complete required inspections within buildings. Additionally, this UAS has a strong signal allowing control of the UAS in metal and concrete environments expanding its capabilities to various construction types.

Line Pulling

Pulling new high voltage power lines during construction is specialized and dangerous work traditionally done by helicopters. This UAS use case saves significant time and money, while reducing risk to employees through the removal of workers exposed to dangerous heights and the elimination of the mobilization of helicopters manned by pilots. Additional benefits beyond the priceless safety factors are the avoided emissions, reduced customer impacts and minimal FAA approval required in comparison to manned flight operations.

Vertical Take Off and Landing – Fixed Wing/BVLOS

This technology offers the advantages of flexibility and maneuverability as the UAS can launch and land almost anywhere and is able to perform actions that are impossible for conventional planes. The need for large open areas is removed, contributing to cost reduction in operations.

This use case also includes operations flown beyond the pilot's line of sight, allowing for greater distances, and maximizing efficiency. The ability to map larger areas quickly and efficiently or survey remote and/or hazardous sites improves safety, saves time, costs, and greenhouse gas emissions, by removing the need for employees driving long distances to perform these tasks.

5.1.2 Initial Selection of Metrics

The metrics common to all use cases are the immeasurable time and safety implications of performing a task using the UAS versus traditional means. Measurable metrics for each of the use cases were defined at the onset of the demonstrations and are provided below.

Use Case 1: Aerial Telepresence

The ability of an interested party to view livestream footage from a tablet, desktop, or phone without being onsite is the primary metric of this use case.

Use Case 2: PSPS Wildfire Mitigation Program & Fixed-Wing

Two metrics were identified for this use case: The first metric measured use of UAS compared to foot patrols and the second metric measured use of UAS compared to helicopter patrols.

Use Case 3: Corona Camera

Two metrics were identified for this use case. The first metric compared the gain and resolution from the handheld camera currently used by the inspectors to the gain and resolution captured with the camera mounted on the UAS. The second metric compared how long it would take to complete the inspection using current methods, via truck and walking, versus how long it would take using the UAS with the integrated corona camera.

Use Case 4: Tethering

The measurable goals of this use case included:

- Testing of the extended use of the tethered drone
- Evaluation of the video zoom and infrared (IR) capabilities
- Evaluation of the livestreaming capability of the tethered drone
- Testing of the radio repeater technology.

Use Case 5: Sense and Avoid

The measurable goals of this use case included:

- Complete operations near critical infrastructure with assurance to avoid collisions
- Confirm the capability of the use case to eliminate setup time for complex site access requirements
- Completion of three confined space inspections annually
- Completion of hazardous environment inspection, eliminating the need for scaffolding
- Ability to conduct troubleshooting of outages or faults

Use Case 6: Line Pulling

Three metrics were identified for this use case including, comparison of the time required for the UAS crew to pull the line compared to the helicopter, the comparative impact to customers when evacuation and relocation was required if a helicopter was used to perform the project, and the comparison of the time required to obtain FAA approval for a Congested Airspace Plan when using a helicopter instead of UAS.

Use Case 7: Vertical Take Off and Landing

The metric defined for the use case was the verification of the processing time expectations to obtain approval for airspace for BVLOS.

5.2 Description of Pre-Commercial Demonstration

Pre-commercial demonstration showed initial validation of UAS projects relating to advanced image processing for electric utility inspection and operations. Key project sensitivities included the timing of relevant permits and approvals for demonstration and full field commercialization.

5.2.1 Location

Locations of demonstrations by use case are provided in Table 1 below.

Table 1. Demonstration Locations by Use Case

Use Case	Demonstration Location
Aerial Telepresence	Mission Valley, Valley Center and La Mesa
PSPS Wildfire Mitigation Program and Fixed Wing	Northeast, Eastern, and North Coast Districts

Use Case	Demonstration Location
Corona Camera	Carlsbad, Mission Valley, Jacumba, and Chula Vista
Tethering	Mission Valley Skills Training Center, Chula Vista Salt Creek Golf Course, Mt. Miguel Mountaintop, and Mt. Laguna
Sense and Avoid Technology/Confined Space Indoor Inspections	Mission Valley Skills Training Center, Palomar Energy Center, and Miguel Synchronous Condenser
Line Pulling	San Juan Capistrano for the South Orange County Reliability Enhancement (SOCRE) Project, in Santa Ysabel, Mt. Laguna, and Carlsbad
Vertical Take Off and Landing/BVLOS	Chula Vista Salt Creek Golf course for demonstration flights of aircraft. A temporary flight restriction (TFR) shown in Figure 1 for BVLOS, was in effect for the test period in a 2.5-mile radius area in the Warner Springs area.

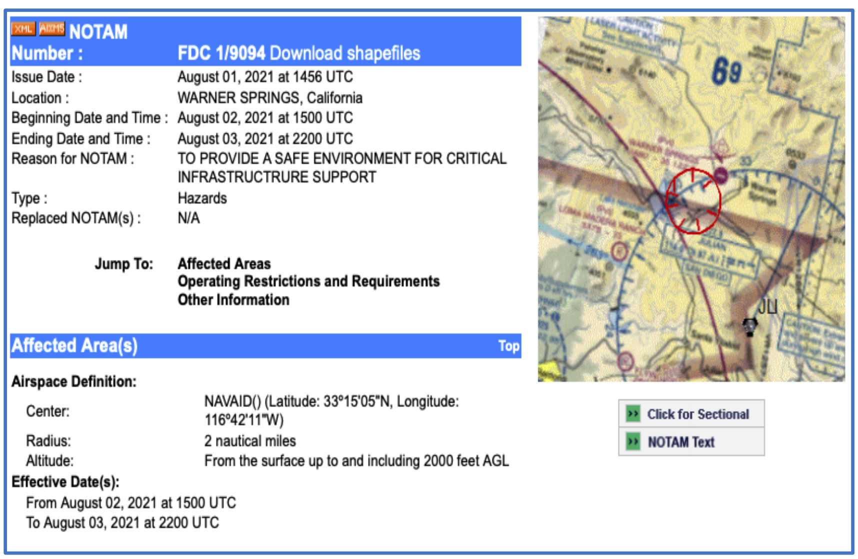

Figure 1. August 1, 2021, Notice to Airmen (NOTAM)

5.2.2 Equipment Requirements

Equipment required by use is provided in Table 2 below.

Table 2. Equipment Requirements by Use Case

Use Case	Equipment Required
Aerial Telepresence	UAS, tablet, cell tower booster, instruction materials, track ball mouse

Use Case	Equipment Required
PPS Wildfire Mitigation Program and Fixed Wing	Rotorcraft UAS and a fixed wing UAS
Corona Camera	UAS and Corona Camera
Tethering	Tethered UAS, power source, Toughbook Laptop, radio transceiver
Sense and Avoid/Confined Space Indoor Inspections	Two types of UAS for indoor and outdoor applications
Line Pulling	UAS with a custom-built line pulling mechanism
Vertical Take Off and Landing/BVLOS	Fixed wing UAS and one rotorcraft UAS

5.2.3 Software Requirements

For most of the use cases, software was integrated into the UAS, and no additional software was required. For the tethering use case, vendor proprietary software was needed and for Use Case 1, Aerial Telepresence, and Use Case 2, PSPS Wildfire Mitigation Program; separate mobile applications were required to operate the UAS.

5.2.4 Use Case Execution

The seven use cases defined as part of Task 7 of the project plan and discussed in Section 5.0 were executed as follows:

Use Case 1: Aerial Telepresence

Comparing the traditional workflow of ground-based field inspections, the telepresence UAS allows construction supervisors and other employees to access sites remotely and virtually. Execution of the use case revealed the construction supervisor was able to take control of the aircraft and complete the inspection without physically travelling to the site location, saving significant travel time. Once testing for the aerial telepresence use case began, over 50 hours of testing in total was performed ensuring the UAS met the use case expectations. The following successes and problems were identified during the initial flights.

- Low video stream latency from remote to web
- Easy flight planning software
- Video/Still Images/IR data collected from remote control (RC) or at desktop
- Inoperable outside of cell range
- Web browser limited to Chrome
- Company-issued mobile data terminals are not equipped with required processing cards
- Higher vantage points to launch the aircraft required
- Only a few UAS are supported by this technology
- Limitations in available supported UAS

- Tablets were subject to overheating
- Constant power supply needed in the field
- Latency from application to UAS control inputs

Use Case 2: Night Flights, PSPS Wildfire Mitigation Program & Fixed-Wing

Comparing the traditional method of visual inspection by qualified electric workers (QEW) in difficult-to-access terrain, the PSPS rotorcraft and fixed-wing UAS allow QEW to inspect sites at the site, without traversing difficult-to-access terrain. The rotorcraft and fixed-wing UAS were compared to current practices of visual inspections on foot by QEW. To accomplish the use case demonstration, over 60 hours of testing was performed ensuring the UAS met use case expectations. The following successes and problems were identified during the initial flights.

- Long flight time
- Can fly long distances (miles) without control issues, break in video feed, high altitudes.
- Auto flight or manual flight
- Easy to assemble in field
- No latency in video feed
- Meta data meets ingestion needs
- Video, still, IR data collected
- Using IR camera during night flight helps with seeing the electric lines
- FAA Night Waiver needed for night flights.
- All RPICs must complete Night Flight Training and test before certification for night flights.
- Difficulty finding suitable launch and landing spot for fixed-wing UAS
- Difficulty launching fixed-wing UAS due to challenging launch technique
- Manufacturer offered a limited, six-month warranty on fixed-wing UAS
- Fixed-wing proprietary flight planning software was not user-friendly

Use Case 3: Corona Camera

New practices based on innovative technologies were compared to current practices. For Use Case 3 the UAS and the Corona Camera were used instead of the handheld camera. To accomplish the use case demonstration, over 40 hours of testing and inspection of 50 transmission lattice towers were conducted. The following successes and problems were identified during the initial flights.

- Data collected was better than the hand-held result that is used current day
- Can stay in on location and fly many structures without driving to each location
- Easily integrated onto aircraft without issues
- Performed as expected and will be used in hard-to-reach areas
- Micro-secure digital (SD)card must be permanently installed in the UAS, or no corona features are displayed
- Power cable from camera to the drone was getting twisted and disconnected
- Flight telemetry location covered up vital corona camera data
- Camera operator video feed went out intermittently

- UAS did not have a first-person view (FPV) camera, requiring integration of one

Use Case 4: Tethering

The tethered drone was compared to helicopter and other UAS practices. The live-stream technology was a unique solution. To accomplish the use case demonstration, over 50 hours of testing the tethered drone and live-streaming capabilities was performed. The following successes and problems were identified during the initial flights.

- Easy set up in field
- Easy to control using tablet or RC
- Still/IR Data Captured
- Live-streaming had low latency (six-second)
- Can fly up to 200 ft above ground level (AGL)
- Low Air recommended maintenance
- No battery changing, powered by generator or electrical source
- The tethered drone cannot be flown within 300 feet of 230 kVA and higher voltage power lines
- The mountaintop repeaters needed to be upgraded to a newer version
- Live streaming required a licensed network
- Live-streaming had a six-second latency
- Corporate firewalls prevented functional live streaming
- Radio repeater too heavy to mount to the tethered UAS

Use Case 5: Sense and Avoid/Confined Space Indoor Inspections

Comparing the traditional confined space inspection using scaffolding construction, the sense-and-avoid UAS saves time and provides significant cost reduction. It removes the safety hazards of scaffolding construction and navigating dangerous height environments. To accomplish the use case demonstration, over 10 hours of testing was performed ensuring the UAS met the use case expectations. The following successes and problems were identified during the initial flights.

- Easy to fly
- Quick set up
- Small/portable
- Senses and avoids all objects tested
- Can be flown indoors and in tight spaces
- Portable repeater is used to communicate between RC and aircraft
- Ten-minute flight time per battery, requiring repeated launch and landings to swap batteries
- Maximum of 40 cycles and battery is recommended for decommission; manual tracking required
- High volume especially in confined spaces (109 decibels)
- Limited propeller life (10 hours), requiring repeated launch and landing/manual process to track flight times
- Limited motor life (25 hours), requiring manual process to track flight times

- Low resolution (12 megapixels) resulted in blurry close-up images

Use Case 6: Line Pulling

For this use case, the line pulling UAS was used instead of traditional methods of line-pulling using a helicopter, eliminating the need for crews walking the line through environmentally sensitive areas or using a device to shoot the line over canyons or valleys. To accomplish the use case demonstration, over 20 hours of testing to ensure the UAS met use case expectations was conducted. Upon completion of testing, over 15 hours of actual use case flights were performed to include 52 spans (distance between each pole) and over 15,000 linear feet. The following successes and problems were identified during the initial flights.

- Easy set up
- Proven to be time/safety efficient in hard-to-reach terrain
- Avoids disturbing soil and sensitive vegetation
- Release mechanism integrated onto aircraft was successful
- Saves time with flight planning and coordination with the FAA
- Low emissions, both noise and greenhouse
- No customer evacuations needed in the area
- RPICs able to hand-off control for long spanned flights
- Challenges were encountered when there was insufficient jet line to cover the full span
- Communication challenges between the RPICs when spaced too far apart between spans. This was corrected by having a supervisor accompany the RPIC with a radio

Use Case 7: Vertical Take Off and Landing – Fixed Wing/BVLOS

To accomplish the use case demonstration, over 40 hours of testing was conducted to ensure the UAS met use case expectations. To accomplish the BVLOS use case demonstration, over six hours researching the process for BVLOS and completing the administrative requirements to acquire a TFR was performed. The following successes and problems were identified during the initial flights.

- Long flight time
- Can fly long distances (miles) without control issues, break in video feed, high altitudes.
- Instant keyhole markup language (KMZ) file creation for instant ingestion into geographic information system (GIS)
- Auto flight, manual override available if needed.
- Easy to assemble in field
- Low latency in video feed
- Metadata meets ingestion needs
- Difficulty finding suitable launch and landing spot for fixed-wing UAS
- Difficulty launching fixed-wing UAS due to challenging launch technique
- Manufacturer offered a limited, six-month warranty on fixed-wing UAS
- Fixed-wing proprietary flight planning software was not user-friendly.

6.0 Results

A summary of results for each of the seven use cases is provided in Table 3 below.

Table 3. Results Summary by Use Case

	Learnings to Date	Problems or Issues Encountered	Transition Plan
Use Case 1 Aerial Telepresence	The software was successfully tested on a hard-to-reach segment of overhead lines which are listed as possible circuits patrolled during a PSPS (pre/post) event for construction districts. The flight locations are usually in hard-to-reach areas with limited cell coverage. Requires a signal booster. Vendor software will only support US-built aircraft.	Incident support vehicle (ISV) Wi-Fi was unreliable and should not be relied upon as the only network. During the June 15, 2021, test run, the project team ran into a dead zone and had to relocate to higher ground. This issue is now considered for future PSPS patrols with a successful UAS launch location noted for future flights within this area. iPads overheated during the same flight which halted operations for 30 minutes. Need to ensure during high temperatures, the remote-control monitors are shaded and not in direct sunlight.	ASD will need to provide support in the field due to the complexity of the system. This technology is available for any company business unit for support with data viewable via the weblink.

	Learnings to Date	Problems or Issues Encountered	Transition Plan

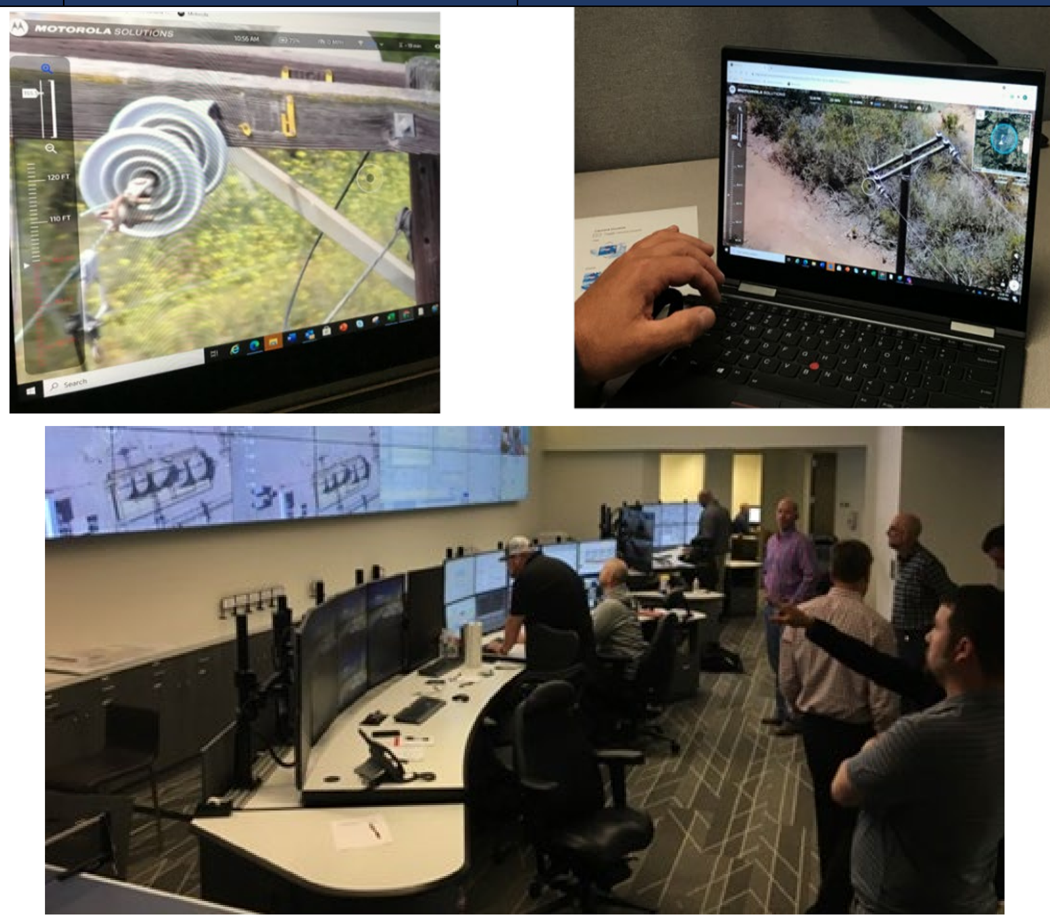

Figure 2. Aerial Telepresence Imagery

	Learnings to Date	Problems or Issues Encountered	Transition Plan
Use Case 2 PSPS/Wildfire Mitigation Program	Aircraft camera performed better than expected but night flights are not supported.	None to report (NTR).	ASD has gathered seven areas to support during a PSPS event for the Northeast and Eastern Districts. ASD created PSPS support reports for easy flight planning.

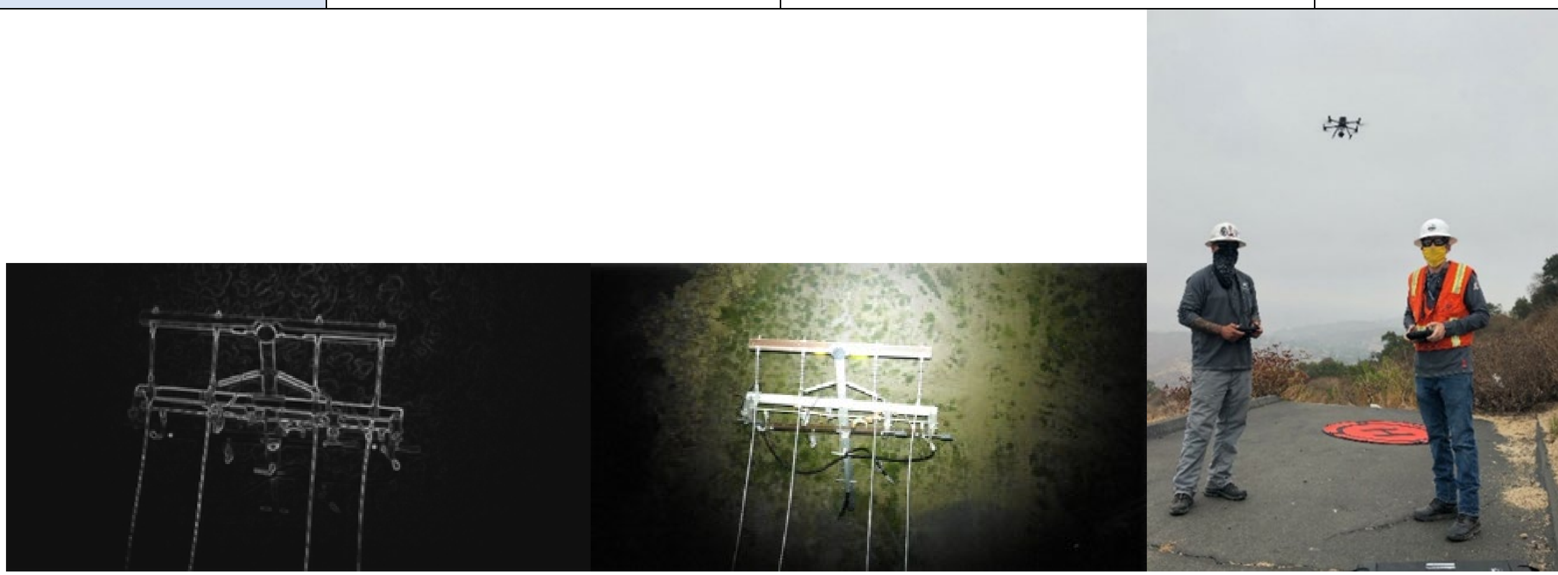

Figure 3. Night Flight/PSPS/WMP Imagery

Use Case 3 Coronal Camera	Using the UAS cuts down the assessment time by half.	Licensed thermographers are necessary.	The Coronal UAS was transferred to TCM for use and

<table>
<tr><th></th><th>Learnings to Date</th><th>Problems or Issues Encountered</th><th>Transition Plan</th></tr>
<tr><td></td><td></td><td>Communication issues with vendor in different time zone.</td><td>ownership in late 2021. ASD will provide support as needed.</td></tr>
<tr><td colspan="4">
Figure 4. Corona Camera</td></tr>
<tr><td>Use Case 4 Tethering</td><td>Long flight time was successful with no requirement to change the battery.
Hoverfly software connected to ISV then stream to the Emergency Operations Center (EOC) or Flight Operations Base (FOB). This testing was</td><td>Battery version issues with the demo unit.
Communication relay for the fire coordinators using 800 MHz radios. Looking for a solution as the product used is too heavy to carry on the UAS.</td><td>This unit will be available to support various business units as needed during emergencies or various company situations due to zoom/IR camera and the ability to live stream back to ISV</td></tr>
</table>

	Learnings to Date	Problems or Issues Encountered	Transition Plan
	successful, once with low latency but with significant support by IT and the vendor.		via cable. The unit has been on display with ISV during many public gatherings and has the attention of many fire and public agencies for added assistance as needed.

Figure 5. Tethering Imagery

	Learnings to Date	Problems or Issues Encountered	Transition Plan
Use Case 5 Sense and Avoid/Confined Space Indoor Inspections	The unit used for outdoor applications is very small and hard to see at a distance. The unit used for the indoor use case had no issues and was easy to fly.	Unable to use the units purchased in June 2020 for Use Case 1 Aerial Telepresence as there is no longer support for the units. It was difficult to schedule demonstration for vegetation management. Does not seem stable outdoors.	The unit will remain with ASD until a particular business unit has the need for a small sense and avoid aircraft. Quality Assurance Quality Control (QAQC) Inspections Group is looking into the indoor use case unit and could be a potential candidate for commercial adoption. Committee approved the indoor use case purchase after the last quarterly meeting. The unit was received in August 2021 and transferred to Palomar Energy Center.

<table>
<tr><th></th><th>Learnings to Date</th><th>Problems or Issues Encountered</th><th>Transition Plan</th></tr>
<tr><td colspan="4">

Figure 6. Sense and Avoid Technology/Confined Space Indoor Inspections Imagery</td></tr>
<tr><td>Use Case 6 Line Pulling</td><td>Lessons were learned after each mission resulting in continuous improvement.

May require a special RPIC skill set for handling off controls to second RPIC during a flight.</td><td>Promoting the use case to all districts for use in hard-to-reach areas.</td><td>The operation and systems will remain in ASD as this flight type requires special RPIC skills.</td></tr>
<tr><td colspan="4"></td></tr>
</table>

<table>
<tr><th></th><th>Learnings to Date</th><th>Problems or Issues Encountered</th><th>Transition Plan</th></tr>
<tr><td colspan="4">
Figure 7. Line Pulling Imagery</td></tr>
<tr><td>Use Case 7 Vertical Take Off and Landing – Fixed Wing/BVLOS</td><td>Nothing to report for this use case.</td><td>Due to supply issues and no delivery until the unit was fully paid, the unit was borrowed from the vendor to complete the use cases.

Local fire agency was understandably hard to reach during fire season.</td><td>This unit was not purchased due to the difficult launch and land procedures.</td></tr>
</table>

	Learnings to Date	Problems or Issues Encountered	Transition Plan
		Very difficult to launch and land as large clear area is needed.	

Figure 8. Fixed Wing Imagery

6.1 Results Discussion

Aerial Telepresence

Five test flights were performed with various electric construction districts internally. During each test flight, the UAS aircraft and platform were evaluated to ensure safe flights before streaming the live video or handing off controls to someone offsite. The offsite staff was able to control the camera, zoom in/out as needed and collect footage as desired. Controls were handed off to the offsite staff members who were able to fly the UAS safely. Overall, the flights were successful with the new technology.

Night Flights/PSPS/Wildfire Mitigation Program

Rotorcraft UAS Demonstration: Three hard-to-reach, short overhead span areas were identified in Escondido and Pine Valley that would have been inspected on foot during a PSPS event. The rotorcraft UAS was used on August 24 and August 25, 2021. The QEW assessed 13 poles in 15 minutes in the Escondido area, and 10 poles in 15 minutes in the Pine Valley area. A second inspection was performed on eight poles in 15 minutes at a separate location in Pine Valley. Using the UAS saved an estimated three hours of time versus performing a hike-in/hike-out inspection in rugged terrain. Any reduction in time reduces impact to the customer during a PSPS event and reduces risk to QEW.

Fixed-Wing Demonstration: Fixed-wing flight was demonstrated in the Warner Springs area on August 2nd and 3rd, 2021. Using the UAS saved an estimated 45 minutes of time versus performing a hike-in/hike-out inspection in rugged terrain. As in the rotorcraft demonstration, any reduction in time reduces impact to the customer during a PSPS event and reduces risk to QEW.

Night Flight Demonstration:

Two night-flights were conducted once SDG&E obtained the UAS FAA Night Waiver and RPICS passed the FAA required night flight operations training and test. The test successfully demonstrated the ability to safely fly UAS during night hours. Pre-planning of the area in daylight per the FAA regulations helps result in the success of the flights. Night flights will only take place during emergency situations and will be dispatched by SDG&E Emergency Management.

Corona Camera

The project team assessed 12- 230 kV tower structures which took about an hour to complete. Normal operation involves the use of a handheld camera requiring travel to each structure taking approximately four hours and about 20 mins per structure to perform the assessment. The typical cost savings is approximately $100 per labor hour with the number of hours varying from site to site.

The project team assessed 20-230 kV and 4-138 kV transmission structures taking a total of 46 minutes of flight time using the UAS. Traditional methods would have taken the thermographer seven hours with some structures inaccessible due to terrain. The typical cost savings is approximately $100 per labor hour with the number of hours varying from site to site.

Comparing the handheld camera and the UAS mounted camera produced the same results 75% of the time. The other 25% was dependent on the altitude of the aircraft and the distance to the structure. For optimum results, the angle and distance does matter, preferably 30 feet away from the object of interest.

Tethering

Aerial live-streaming capability utilizing UAS, provided efficiency and was safer than helicopter alternatives which have the same capability. Costs using a UAS were significantly lower than a helicopter and did not have the flight time limitations due to fuel capacity.

Sense and Avoid Technology/Indoor Confined Space Inspections

This use case was applied to an inspection area 300 feet in height and could potentially cost $38K annually to build the scaffolding that is needed to complete this annual inspection. The scaffolding build process alone takes days, and then the inspector will use the scaffolding to inspect the confined space which takes many more labor hours. During the test case, an actual inspection was tested and was successfully completed in one and a half hours. Current practices would have taken an estimated two weeks or more. During the second live test inspection the sense and avoid UAS was flown inside of the communications warehouse that is three stories tall. The UAS was used to inspect pipes, welding points of the building's structural condition and other potential flaws that may have never been inspected. The use of this UAS will continue to grow as it is now commercialized internally.

Line Pulling

The line pulling UAS provides significant benefit to customers by eliminating the need to evacuate the work area. Homeowner evacuations within a minimum 150-foot radius of the flight operations area are required when using a helicopter. This makes it a challenge to manage the amount of people in an area, so they do not encroach operations.

The UAS also saves time by removing the need to file a congested airspace plan with the FAA. Additional advantages include decrease of environmental impact in confined areas and the reduction of risk to QEW crews as compared to a manned helicopter flying overhead.

Results of Use Case 6 Line Pulling demonstrations are provided in Table 4 below.

Table 4. Line Pulling Results

Date	Project Location	Spans	Lines per span	Linear Feet	# of Pulls	Time	RPIC Position	Lineman on Pole	Notes
7/23/2020	CNF - Pine Valley	7	5	1600	35	4 hours	Ground	Y	Individual pulls from pole to pole. RPICs ground based, lineman in bucket

Date	Project Location	Spans	Lines per span	Linear Feet	# of Pulls	Time	RPIC Position	Lineman on Pole	Notes
11/9/2020	SOCRE - San Clemente	3	1	3000	2	1hr or less	Bucket	Y	The line used during operation came free and wrapped around the nearby transmission line
11/19/2020	FiRM - Santa Ysabel	35	1	10000	35	6-7 hours	Bucket	Y	Divided into two separate sections
3/29/2021	ERO ME - Mt Laguna	6	4	1200	8	1 hour	Bucket	Y	Long continuous pull
4/6/2021	ERO NC - Carlsbad	1	4	~250 ft	4	45 minutes	Ground	N	Pulled mule tape from base of pole to base of pole
11/1/2021 - 12/1/2021	Ramon	96	1	573, 919	96	159 hours	Ground & Bucket	At times	Pulled jet line for a future fiber optic job from sub to sub

Vertical Take Off and Landing – Fixed Wing/BVLOS

Comparing traditional operation of UAS within line of sight of the RPIC, the BVLOS UAS offered more efficiency with less landings and takeoffs due to relocating saving time and money.

Flight No. 1: Fixed wing flight demonstrated the fixed wing UAS to travel three miles beyond visual line of sight with no connectivity problems.

Flight No. 2: Rotorcraft flight demonstrated the rotorcraft UAS to travel four miles beyond visual line of sight with no battery or connectivity issues.

Flight No. 3: Attempted third flight with fixed-wing UAS but could not find suitable takeoff area.

6.2 Updated Benefits Analysis

The demonstrated use cases provided significant insights into the potential of UAS to increase reliability, safety, and cost efficiency in power system operations. A summary of confirmed benefit highlights include:

- Increased Safety - Unmanned Aircraft Systems can access environments that are hazardous to humans
- Effective tool for use in vegetation management, situation awareness during emergency, public safety, and wildfire mitigation
- Avoided emissions and need for public evacuations that are associated with helicopter flights
- Time savings in flight planning and authorizations

- Avoided costs and risks of human travel into isolated and/or distant locations
- Cost savings for confined space inspections
- Operating cost savings flow through to lower ratepayer costs

6.3 Commercialization Cost Estimate

Aerial Telepresence

The cost of the software is approximately $80,000 for an annual subscription for six aircrafts. No other items are required to support this use case. Commercializing internally requires reassessment as there are peaks and valleys of interest. Live streaming data from an aircraft is not practiced by SDG&E to date.

Night Flights/Public Safety Power Shutoff (PSPS)/Wildfire Mitigation Program (WMP)

No other reoccurring costs are required, other than employee time to support it. During such events there is a charge order that covers the employee's labor expenses. WMP is currently funded by the project team with internal discussions taking place about conducting SDG&E Drone Investigation and Repair (DIAR) UAS assessments in-house and not by contractors.

Corona Camera

The cost per corona camera is approximately $58,000 per camera. The number of UAS and corona cameras needed is left to the commercializing stakeholder group to determine.

Tethering

The cost per tethering unit is approximately $100,000. No other outside costs are required once the UAS is purchased. The number of tether units needed will be determined by the stakeholder group to as the use case matures internally.

Sense and Avoid/Indoor Confined Space Inspections

The cost per sense and avoid UAS is from $2,000 - $50,000 per unit, depending on which UAS. A four-dimensional (4D) mapping license may be added at a cost of $8,000.

Line Pulling

The complete cost per UAS kit is approximately $35,000. This includes extra batteries and a battery charging station. Additional cost for the line pulling system mechanism is approximately $500. The drop system is estimated at approximately $1,000.

Vertical Take Off and Landing – Fixed Wing/BVLOS

Acquiring BVLOS authorization from the FAA is free of charge. It takes less than an hour to complete the required paperwork once familiar with the process. The complete cost for a full rotorcraft UAS kit is approximately $35,000.

7.0 Conclusions

Aerial Telepresence

While this demonstration confirmed the ability to operate the aircraft and perform an inspection manually, issues were identified with the technology requiring ASD support in the field. The technology is available for internal business use with expected improvements on performance with the 5G network.

PSPS Wildfire Mitigation Program, WMP & Night Flights

The use case was adopted for commercial use. Seven hard-to-access areas for public safety power shutoff were identified with patrols now using UAS. WMP UAS flights are currently being conducted via the SDG&E (DIAR) Program and have proven successful. The DIAR Program was implemented after EPIC-3 Project 5 was kicked off for testing. Night flights will not be conducted for PSPS as the patrols are not conducted after sunset.

Corona Camera

The demonstrated technology performed its intended functions successfully. This technology is ready for commercialization for use within a utility to complete corona inspections by a certified thermographer.

Tethering

This technology performed its intended functions successfully and was adopted for commercial use.

Sense and Avoid/Confined Space Indoor Inspections

The demonstrated outdoor use case proved the technology can sense and avoid thin power lines and guy wires. The indoor use case was also successfully executed through demonstration of actual confined space inspections. Both were determined as high-value solutions and are in commercial use.

Line Pulling

Successful demonstration of this use case was determined as high-value and is in commercial use.

Vertical Take Off and Landing – Fixed Wing/Beyond Visual Line of Sight (BVLOS)

Due to the difficulty with launch and land procedures, the fixed wing unit was not purchased, and the associated use case will not be pursued commercially. BVLOS was verified with a quadcopter UAS, and the FAA approval process was easily obtainable. (A quadcopter is defined as a type of helicopter with four rotors.)

8.0 Tech Transfer Plan

8.1 Project Result Dissemination

The results of this project will be disseminated throughout the industry in the following ways

SDG&E Website

This comprehensive final project report is the main tech transfer documentation for the project. All EPIC final project reports are posted to the SDG&E website at: https://www.sdge.com/epic. The website also includes annual updates that were made over the life of the projects. These documents are also filed with the CPUC.

EPIC Symposium

The project results were shared with California Investor-Owned Utilities through the annual EPIC symposiums and other EPIC workshops. During these meetings, information on various EPIC projects is shared with public audiences.

Industry Conferences and Publications

SDG&E personnel worked with the product vendors to develop presentation material outlining the results of this report. These presentations are offered, as may be appropriate, for inclusion at industry conferences such as DISTRIBUTECH, IEEE conferences, Utility Week, Grid Modernization Forum, and others.

9.0 Recommendations

This project successfully demonstrated the value proposition for UAS and the newly mounted sensors that were tested. Based on the findings and results in the demonstrations, it was determined that the use cases for aerial telepresence and vertical take-off and landing are not yet ready for commercial adoption in SDG&E's applications. The remaining use cases however, including PSPS/WMP, coronal camera, sense and avoid, confined space indoor inspections and line pulling, proved the UAS could perform the tasks intended, and those technologies are now in commercial use at SDG&E. This EPIC project is now completed. Given the successes of this EPIC project, it is recommended that additional work be done to further evaluate and expand use of these UAS technologies and use cases to identify others that can be used commercially in future utility system operations. It is also recommended that the appropriate internal stakeholder group within SDG&E be identified to lead the commercialization and operational use of the technologies that were demonstrated in the EPIC project.

EPIC Final Report

Program	Electric Program Investment Charge (EPIC)
Administrator	San Diego Gas & Electric Company
Project Number	EPIC-3, Project 7, Module 1
Project Name	Demonstration of Multipurpose Mobile Battery
Date	December 31, 2021

Attribution

This comprehensive final report documents the work done in Electric Program Investment Charge (EPIC) 3, Project 7, Module 1. The project team that contributed to the project definition, execution, and reporting included the following individuals, listed alphabetically by last name:

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Executive Summary

Objective

The EPIC-3 Project 7 objective was to undertake a pre-commercial demonstration of a mobile battery energy storage system (MBESS) and examine the value proposition from deploying a mobile battery across multiple sites and use cases. With the MBESS functionally between a mobile diesel generator and a stationary battery energy storage system (BESS), this study sought to quantify the benefits of a flexible deployment of a MBESS to determine whether the benefits derived from a flexible range of services provided could justify the significant upfront costs associated with purchasing a MBESS.

Approach

EPIC-3 Project 7 was split into two modules (workstreams) involving two different MBESS units having different characteristics. This report documents the work in Module 1, which used the larger of the two MBESS units. The Module 2 work is documented in a separate report. For Module 1, SDG&E competitively procured a 362kW/1499kWh MBESS mounted on a gooseneck trailer with project funding. Sites with different use cases were considered and SDG&E entered negotiations with potential sites to ensure that the MBESS could be deployed for the intended use cases. Ultimately SDG&E selected two sites for MBESS deployment, Marine Group Boat Works, a Port of San Diego tenant, and the Cameron Corners Microgrid.

In parallel with site selection, SDG&E developed potential use cases and created the testing regimen for the MBESS. The testing regimens were designed to test the various use cases and quantify potential MBESS benefits. Each testing plan included a data collection plan to ensure that data collected was appropriate and sufficient to model test results and draw conclusions about the MBESS' ability to fulfil the intended use cases and quantify the benefits of the MBESS.

The MBESS was ultimately deployed at 3 different sites – an initial Commissioning and User Acceptance Test at SDG&E's Skills Training Facility, at Marine Group Boat Works and finally at Cameron Corners Microgrid.

The MBESS performed grid support services at Marine Group Boat Works connected in a grid paralleled fashion, ultimately performing a safety test, load smoothing, peak shaving, zero load, battery charging and discharging tests. At the Cameron Corners Microgrid, the MBESS performed resiliency functions, with the microgrid's existing infrastructure serving as an ideal testbed for MBESS deployment in similar situations around SDG&E territory. A load blackstart test was performed for downstream critical community loads. These loads included community facilities, a health clinic, telecommunications, fire station and gas station which SDG&E had previously undergrounded to provide increased public safety power shutoff (PSPS) resiliency. This test successfully demonstrated the load blackstart use case.

Key Findings

Testing the MBESS demonstrated the flexibility and value of a relocatable resource to SDG&E's distribution system, which was not possible from a single mobile diesel generator or a stationary BESS. The MBESS demonstrated the following benefits:

- Safety – The MBESS contributed to a safer worksite through development of customized deployment safety protocols and emergency stop functionality. It also proved to reduce runtime of more traditional diesel generators, decreasing the risk for a fuel spill and contributing to a quieter work environment and better air quality.
- Improved Reliability and Power Quality – The MBESS was able to demonstrate a successful load black start and coordinate the integration of other connected DERs to carry downstream loads for 24 hours. It also successfully shaved peak loads up to and exceeding its 362kW rating and load smoothed peaky customer loads down to a rate of change of 126 Watts/sec. When considering associated temperature decreases due to amperage reductions at the substation, the MBESS has the potential to increase grid infrastructure by 2.78 years, worth an estimated $170,389 over 10 years. The MBESS can also be used to offset planned grid upgrades, worth an estimated $141,618 per year.
- Improved Performance of the Utility Power System – Deployment of a 362kW MBESS was able to reduce circuit amperage, loading, and electrical losses by roughly 10%. Estimating a 362kW load reduction at 12kV, the resulting 30A reduction can yield a 6% decrease in total circuit loading.
- Lower GHG Emissions – Direct GHG reductions from a single MBESS reduce diesel generator fuel consumption by 303 gallons of diesel fuel, worth approximately $1,516. The same reduction in diesel fuel consumption eliminates the emissions of three metric tons of Carbon Dioxide Equivalent (CO_2e), worth about $72 in California's current Cap and Trade market. MBESS use could also allow customers to mitigate the temporary bill increases due to EV charging or ship-to-shore power, encouraging more indirect GHG emissions reductions.
- Lower Operating Costs and More Efficient Use of Customer Money – When compared to a diesel generator, the MBESS demonstrates $653,424 more in net benefits than a diesel generator rental over a 10 year period. When not actively deployed, a MBESS can also participate in the CAISO market, generating an estimated $14,660 in energy and regulation revenue.
- Economic Development – Should SDG&E choose to purchase or lease a fleet of MBESS to offset their entire power system 2021-2030 needs, it would generate a local market of over $11.4M in MBESS requiring sales, service, transportation and deployment support, creating local jobs.
- Disadvantaged Communities (DACs) – Deploying an MBESS in a DAC territory supports existing efforts to reduce GHGs, emitting no direct emissions itself and supporting other local and state efforts such as those associated with using shore power for ships when in dock and EV and forklift charging.
- Incremental Benefits of a Mobile Solution – Deployment of an MBESS is flexible and customizable to the specific application, able to easily rotate between events and grid support functions, where otherwise it would be cost prohibitive and/or infeasible to deploy a stationary battery. MBESS are also daisy-chainable, so multiple units can be deployed together to achieve higher total ratings, when needed.

Recommendations

The Mobile BESS tested in this EPIC project has a strong value proposition for deployment around SDG&E territory. Sized appropriately, it provides analogous function to a mobile generator which can black start loads after an outage, coordinate with other supporting generation sources, and carry loads until grid power can be restored. Because it is mobile, the MBESS can also provide grid support services which help demonstrate significant value over a diesel generator over the 10-year life of a MBESS. It is recommended that SDG&E continue to standardize deployment applications for a MBESS and commercially adopt and use these valuable assets in their service territory. A fleet of mobile batteries of different types, capacities and ratings should be considered. Both purchase and lease options for the mobile battery fleet should be considered.

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List of Acronyms

Acronym	Acronym Description
AB	Assembly Bill
BESS	Battery Energy Storage System
BtM	Behind the Meter
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCM	Cameron Corners Microgrid
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CPUC	California Public Utilities Commission
CT	Current Transformer
DAC	Disadvantaged Community
DDOR	Distribution Deferral Opportunity Report
DER	Distributed Energy Resource
EMP	Energy Master Plan
EO	Executive Order
EPIC	Energy Program Investment Charge
E-Stop	Emergency Stop

Acronym	Acronym Description
FtM	In Front of the Meter
GHG	Greenhouse Gas
GNA	Grid Needs Assessment
HFTD	High Fire Threat District
HMI	Human Machine Interface
IOU	Investor-Owned Utility
LNBA	Locational Net Benefit Analysis
MBESS	Mobile Battery Energy Storage System
MGBW	Marine Group Boat Works
PCC	Point of Common Coupling
PQ	Power Quality
PV	Photovoltaic
PSPS	Public Safety Power Shutoff
PT	Potential Transformer
RFP	Request for Proposals
SB	Senate Bill
SCADA	Supervisory Control and Data Acquisition
SDG&E	San Diego Gas and Electric
SOE	State of Energization
UPS	Uninterruptable Power Supply

1.0 Introduction

The quantity of deployed Battery Energy Storage Systems (BESS) is quickly increasing in today's energy market due to the wide variety of potential use cases and rapidly declining costs. According to EIA, battery prices have fallen 72% between 2015 and 2019, a 27% decline per year[1]. BESS of all sizes can fulfil a host of applications, from supporting grid services such as peak shaving and load smoothing, to economic functions such as rate arbitrage and demand response to providing resilient backup power during a grid outage and others. To date, however, BESS installations, especially large-scale ones, have been predominately stationary, installed to support one site, group of sites, or distribution system area requiring the continual use of mobile diesel generators for mobile, flexible grid support. While stationary batteries allow the recipient site to potentially access the aforementioned functionality, there is the potential to increase the benefits of a BESS by making it mobile, increasing the utilization of a single asset by providing grid services and resiliency services, like a diesel generator would today. EPIC-3, Project 7 explored the stacked benefits of a Mobile Battery Energy Storage System (MBESS) and whether mobile application can increase a battery's potential to serve more functions and/or more customer use cases with a single unit, thereby increasing the value proposition for purchasing and using MBESS units.

2.0 Project Objectives

The objective of EPIC-3 Project 7 was to undertake a pre-commercial demonstration of a mobile battery system at multiple sites. The project was split into two modules (workstreams) involving two different MBESS units having different characteristics. This report documents the work in Module 1, which used the larger of the two MBESS units. The Module 2 work is documented in a separate report. For Module 1, SDG&E competitively procured a 362kW/1499kWh MBESS mounted on a gooseneck trailer with project funding. Sites with different use cases were considered and SDG&E entered negotiations with potential sites to ensure that the MBESS could be deployed for the intended use cases. Ultimately SDG&E selected two sites for MBESS deployment in Module 1: Marine Group Boat Works (MGBW), a Port of San Diego tenant, and the Cameron Corners Microgrid (CCM).

While the original intent was for a MBESS deployment at the cruise ship terminal at the Port of San Diego, a variety of factors made deployment at this site infeasible during the pre-commercial demonstration window. So, another site, with similar load trends, was chosen as one of two deployment sites. Ultimately, MBESS deployment was moved between the MGBW and CCM sites to demonstrate the stacked benefits of multiple use cases across various sites. At MGBW, the MBESS was connected in parallel to the grid to offset the highly variable loads associated with ship repair and cold-ironing ships (plugging ships in dry dock into shore power, rather than using diesel engines). At the CCM, the MBESS could support circuit resiliency and backup power during an extended duration outage such as a Public

[1] https://www.eia.gov/analysis/studies/electricity/batterystorage/

Safety Power Shutoff (PSPS). The objective was to evaluate the effectiveness of mobile batteries when rotated between applications and quantify the benefits associated with rotation of a MBESS through preferred applications.

3.0 Issues and Policies Addressed

This project was designed to support the state objective under Assembly Bill (AB) 628 to reduce wasteful, inefficient energy consumption, implement energy efficient improvements and use efficient low-emissions energy sources in the operations of its ports and harbors by supplementing current energy sources through use of battery energy storage. As mentioned above, the project created a platform for gathering new knowledge on stacked benefits from deploying a mobile battery across multiple strategic applications, including but not limited to scheduled charging and discharging, demand response, load smoothing, peak shaving, circuit loading reduction and islanding of grid loads prone to frequent outages.

Another goal of AB 628 is to promote economic development. Implementation of the mobile battery in front of the meter (FtM) aided in demand and energy cost reduction for SDG&E, complimenting the potential benefit through greater stability and decreased cost of energy services for businesses located downstream of the mobile battery deployment. In correlation to this project, maritime customers who consume shore power pass these costs along directly to their customers which in turn can impact the potential for business retention. Thus, this project poses a benefit to help minimize costs which are passed through to customers, allowing local businesses to achieve higher margins on the services they sell to their end customers.

Lessons learned from this project may lead to SD&GE deploying a fleet of mobile batteries. This will help strategic customers around its territory, specifically disadvantaged communities (DACs), reduce emissions of greenhouse gases (GHG) and other pollutants, and reduce periods of heavy localized electric power demand, which directly supports not only the District’s Climate Action Plan but also the California Air Resources Board (CARB) shore power regulation.

In addition, the project demonstration extended to the application of emergency backup power for an at-risk grid circuit in a High Fire Threat District (HFTD). HFTDs are in some of the most fire prone communities and, consequently, are even more prone to losing power during a Public Safety Power Shutoff (PSPS) event. Having mobile battery technology rapidly available to HFTDs would provide a significant level of resiliency to the affected communities.

4.0 Project Focus

Module 1 of this EPIC-funded project focused on pre-commercial demonstration of a mobile energy battery storage to evaluate potential use cases for the battery and to quantify the stacked benefits from a moveable asset. The knowledge gained in this demonstration is being used in the decision-making regarding investment in and deployment of a larger MBESS fleet around SDG&E’s territory. A fleet of MBESS would allow for flexibility in today’s dynamically changing energy landscape.

Once a MBESS was competitively procured from an equipment vendor, sites were selected to demonstrate various use cases of the battery. Existing site infrastructure and current distributed energy resource (DER) interconnection guidelines both determined what use cases could be tested at each site. The use cases then dictated development of test plans which were conducted to demonstrate MBESS functionality. Data was collected which supported the quantification of local use case benefits.

SDG&E worked with a consulting vendor to perform a pre-commercial demonstration of the MBESS's effectiveness in a variety of use cases, with the end goal of helping determine the value proposition of mobile batteries. The purpose was not to evaluate a specific vendor product, but to examine the value proposition for mobile batteries in general.

5.0 Project Scope Summary

5.1 High-Level Overview

While mobile batteries are becoming commercially available, the mobile utilization of the same asset at multiple locations with multiple use cases was new and needed to be demonstrated and thoroughly evaluated. In performing the procurement of mobile batteries for this project, SDG&E learned that a stable mobile battery industry did not yet exist, and vendors were challenged to provide products that met the project needs in a timely manner.

A primary issue for commercial and industrial businesses within the SDG&E service territory is low load usage with high peak demand for relatively short periods, which result in undesirable charges and low utilization of grid assets. Specifically, MGBW has a load profile with high peak demand and low load usage, resulting in a poor load factor and high demand charges. This type of load profile also requires that SDG&E provide significant circuit capacity, which is used only a small fraction of the time.

This project sought to demonstrate a new solution [i.e., MBESS] to assist MGBW and other locations in alleviating these problems. Whereas, pursuing a more traditional behind the meter (BtM) solution for load factor improvements has proven to be prohibitively expensive and infeasible to MGBW, the concept of placing a temporary FtM grid support asset on their property for little or no cost was amenable to site management as an alternative solution to their issues.

As an additional application, the MBESS was also deployed at the Cameron Corners community in Campo, CA. This site is located in a HFTD and is heavily susceptible to PSPS during adverse weather conditions. By connecting the MBESS to undergrounded downstream critical customer loads as part of a larger microgrid, SDG&E demonstrated a potential solution for backup power during emergency response situations such as wildfires and other calamities. In anticipation of extended power outages in the future, SDG&E may energize their Cameron Corners microgrid to provide residents with continued power for water and food supply, medical and health care, vehicle fuel pumping, electronic device charging, telecommunications and fire/emergency response. Enhancing the resiliency of these communities will attribute to the accessibility of resources for affected customers. Strategic deployment of a MBESS into

HFTDs will additionally reduce the need for fossil-fueled diesel generators and subsequent GHG emissions, especially if interconnected as part of a solar-powered microgrid.

6.0 Project Approach

The project plan included the following tasks, designed to set up the mobile battery tests, site selection, data collection model results and draw conclusions about the MBESS's ability to meet certain use cases and any additional stacked benefits associated with a mobile application.

Task 1 - Initiation of Project Plan

- Identification of stakeholders and formation of stakeholder steering committee
- Project kick-off, development of project plan and resource requirements, and formation of SDG&E internal project team

Task 2 - Development of Project Requirements

- Fact finding from literature or other programs

Task 3 - Development of Funding Plan and Site Hosting Requirements

- Baselining current situation and practice for application at two sites
    - MGBW
    - CCM
- Development of a Funding Plan

Task 4 - Site Selection and Arrangements

- Site Selection for grid paralleling use cases (MGBW)
- Site Selection for grid islanded use cases (Cameron Corners) in HFTD territory.

Task 5 - Preparation of RFP for Procuring Competitive Bids to Supply Mobile Battery

- Develop Requirements for the RFP
- RFP Release, Proposal Evaluation and Vendor Selection

Task 6 - Preparation of Use Cases and Test Plan

- Preparation of Use Case(s) for MGBW
- Preparation of Use Case(s) for the CCM

Task 7 - Development of Test Set-Up and Modelling Capability Support

- Set-up test parameters and measure results from the application of peak shaving, voltage regulation and end-use demand charge reduction for MGBW facility.
- Accurately prepare test parameters and gauge outcomes that result from the application of emergency backup power duration from a MBESS.

- Identify metrics to support collecting data to test the initial benefits estimate. Also, identify metrics to judge whether the selected body of use cases was adequate to make conclusive findings and recommendations in the final analysis.

Task 8 - Execution of Demonstration

- Execution of the demonstration for the MGBW site
- Execution of the demonstration for the CCM site

Task 9 - Assimilation of Test Results

- Assimilate test data in preparation for analysis of demonstration results.
- Collect and process data from demonstration results
- Critically review, by each use case, how well the project objectives were obtained.

Task 10 - Analysis of Data and Test Results from Demonstration

- Analyze the data and other results from the demonstration to provide a basis to support development of key findings, conclusions, and recommendations for the project.
- Critically review all data to understand which use cases were successful in terms of providing cost-effective solutions for using mobile batteries and which were not successful. Determine the value proposition for each use case. Following the analysis, archive the data for future use.

Task 11 - Development of Conclusions and Recommendations

- Develop the key findings, conclusions, and recommendations for the project.
- Use the results of the data analysis task to update the initial benefits analysis and to formulate key findings, conclusions, and recommendations for the project.
- Confirm the success or failure of each use case that was demonstrated. Develop the value proposition for the individual use cases and the collective value proposition for all use cases in terms of stacked benefits.

Task 12 - Preparation and Implementation of Tech Transfer Program for both deployment sites

- Develop, prepare and implement a tech transfer plan
- Identify the process for transferring project results into practical use by SDG&E, as well as by other potential users.
- Indicate which tech transfer activities may have already taken place during the demonstration work, which will be done in the closing of the project, and which will need to be done by the stakeholders after the project ends.
- The tech transfer plan should be consistent with the recommendations made regarding which use cases should and should not be pursued commercially.

Task 13 - Perform Interim Project Reporting

- Perform required interim reporting activities on a regular basis, throughout the life of the project.

Task 14 - Development of Equipment Disposition Plan

- Define and implement a disposition plan for equipment and software used in the project

Task 15 - Preparation of the Comprehensive Final Report Capturing Description of the Work, Results, Conclusions, Accomplishments Relative to Metrics, Recommendations Regarding Commercial Adoption, and Tech Transfer Plan

- Complete a final report for the project, suitable for filing with CPUC and public release
- Consolidate all relevant project milestones, events, task outcomes, conclusions, and recommendations into a single, comprehensive final report.
- The report shall also include a good summary of the final benefits estimate and value proposition for the project.
- This report will be the primary and most complete tool for tech transfer of project results to prospective users.
- The report should be prepared as a draft for review by the stakeholders followed by a final version incorporating stakeholder feedback.

6.1 Baseline Studies/Fact Finding

6.1.1 Initial Benefit Estimate and Value Proposition

EPIC-3, Project 7 was initially targeted to help improve safety, advance power system infrastructure, and improve system operations for the customers' benefit. Implementation of a mobile battery can, therefore, provide benefits in the following areas specified in SDG&E's application to CPUC for approval of EPIC-3 investments.

1) **Improved Safety:** Public and employee safety are very high priorities for SDG&E. Each project, as a minimum, should comply with existing safety policies and not result in any safety violations or safety incidents. In certain cases, a project can minimize safety risk by either reducing probability of a safety incident, mitigating the severity of an incident, or enabling early detection that allows correction/prevention of unsafe situations.
2) **Improved Reliability and Power Quality:** Two goals of power system modernization are to improve the level of reliability and to optimize the quality of power as seen by the customer. Higher reliability means reducing the occurrences of outage and reducing the duration of outages when they do occur. Improved power quality means reducing the disturbances seen in the power itself, such as voltage variation, flicker, and harmonic content in the power waveform.
3) **Improved Performance of the Power System:** Improved system operations and performance (i.e., system electrical efficiency) will help reduce electrical losses in the system, such as reductions in resistive losses associated with current flow through the conductors and reductions in transformer electrical losses.
4) **Lower Greenhouse Gas Emissions:** Advanced infrastructure can help reduce electrical system losses, which in turn will reduce the need for electric generation. Less generation means reduced

greenhouse gas emissions (GHG). Additionally, infrastructure such as battery storage can store electricity from renewable or other low-emission sources and offset consumption during periods where higher-emission sources would be required, also reducing GHGs.

5) **Lower Operating Costs and More Efficient Use of Customer Monies**: Customers can see lower costs on their utility bill through peak demand reduction and shifting utility-delivered consumption to lower-cost time periods. Furthermore, reductions in peak load can defer or eliminate certain utility infrastructure investments and avoid electric procurement and generation costs, ultimately mitigating any potential rate increases.
6) **Economic Development:** A secure source of low-cost, high-quality, reliable electric power is essential to economic development and to retain and attract businesses in California. The purpose of EPIC funding is to support investments in research and development projects that benefit electric utility customers. The utility EPIC activities are limited by the EPIC ordering decisions to precommercial demonstrations of technologies and integration solutions that provide benefits to customers by promoting greater reliability, lower costs, increased safety, and other designated benefits.
7) **Ancillary Benefits:** Finally, EPIC-3 Project 7 will create new knowledge, lessons learned, and potential recommendations on the incremental benefits achieved and incremental costs incurred by rotating a mobile multipurpose battery into different applications and locations. Incremental benefits can include increased utilization of the asset, flexibility to assist with more than one use case, and ability to react to real-time situations more effectively. Incremental costs can include up-front equipment costs, up-front setup and administrative costs (such as for interconnection and/or certification), transportation costs, and ongoing operations and maintenance costs. The final evaluation will need to consider incremental cost-benefit analysis of the project to assess whether a mobile-multipurpose battery solution is cost effective and viable.

As part of pre-demonstration activities, SDG&E estimated the value proposition for deployment of a MBESS:

Value Propositions – SDG&E Customer Programs

SDG&E customer rebate and incentive programs are bound by constraints for permanent and/or stationary equipment. However, in alignment with SDG&E Customer Programs commitment to serve the needs of its disadvantaged community (DAC) customers as it pertains to air pollution reduction, this project demonstration contributes to air quality improvement for the Port District including MGBW, which is adjacent to some of SDG&E's most concentrated DAC areas. The MBESS would also contribute to cleaner air anywhere it offsets emissions from other energy sources.

Value Propositions – State Initiatives

Demonstration of the multipurpose mobile battery supports the state initiative to reduce the emission of GHG by providing augmentation for current emergency back-up solutions (i.e. diesel generators) through alternative energy solutions such as MBESS. Furthermore, assisting with the reduction of GHG emissions in the electricity sector at the lowest possible cost, supporting the Loading Order and contributing to goals related to low emission vehicles and transportation, economic development, and efficient use of ratepayer monies.

AB 628, signed into law by Governor Brown on October 11, 2013, authorizes the San Diego Unified Port District, in conjunction with San Diego Gas & Electric Company, to prepare an Energy Management Plan (EMP) to reduce air emissions and promote economic development in the District. In doing so, the State of California declared the following:

- That it seeks to “promote efficient use of low-cost, low-emissions energy sources in the operations of ports and harbors;”
- That ports offer a unique opportunity to “reduce vehicular emissions of GHG and criteria pollutants;”
- That it “encourages the development of new businesses and retention of existing business within port boundaries;”
- That “businesses located within port and harbor districts may benefit through greater stability in the cost of energy services;” and
- That investor-owned utilities, such as SDG&E, are in the “optimal position" to work with ports to provide energy-related service alternatives and programs.

AB 628 aligns with the State’s broader objective of combating climate change through GHG reductions and energy regulations.

- Governor Schwarzenegger, through Executive Order (EO) S-3-05 and Assembly Bill (AB) 32, required the State to reduce its GHG emissions by 80% below 1990 levels by 2050.
- Governor Brown further required, through EO B-30-15 and codified through Senate Bill (SB) 32, the State to reduce its GHG emissions by 40% below 1990 levels by 2030.
- The State went even further with SB 350, which required that energy efficiency be cumulatively doubled by 2030 and that 50% of electricity generated and sold must come from renewable energy resources by 2030.
- Governor Brown, through EO B-16-2012, also set a goal of having 1.5 million zero emission vehicles on the road by 2025.

California Air Resources Board Shore Power Regulation (CARB)– Section 93118.3 Airborne Toxic Control Measure for Auxiliary Diesel Engines Operated on Ocean-going Vessels At-Berth in a California Port

A cruise ship that visits a California Port five times or more in a calendar year fall under this regulation, and has requirements for 2014, 2017 and 2020.

2014 - At least 50% reduction of onboard auxiliary diesel engine power generation while docked at berth

2017 - At least 70% reduction of onboard auxiliary diesel engine power generation while docked at berth

2020 - At least 80% reduction of onboard auxiliary diesel engine power generation while docked at berth

Value Propositions – HFTD Emergency Support

SDG&E's tier 3 region consists of areas on the CPUC Fire-Threat Map where there is an extreme risk, including likelihood and potential impacts on people and property, from wildfires associated with overhead utility power lines or overhead utility power line facilities also supporting communication facilities. Tier 3 is distinguished from Tier 2 by having the highest likelihood of utility-associated fire initiation and growth that would impact people or property, and where the most restrictive utility regulations are necessary to reduce utility fire risk (taken from Sec 2.8. in TMC1320).

Demonstration of the multipurpose mobile battery may not only support State initiative to reduce GHG emission but also introduce a capability for enhancing wildfire mitigation resource resiliency, specifically in-line with Community Resource Center (CRC) back-up power solutions. This proposition has the potential to expand integration with renewable generation such as solar, creating a medium scale microgrid to carry larger load pockets within those communities during extended emergency power outages (8 hours or longer).

6.1.2 Initial Selection of Metrics

EPIC-3 Project 7,Module (1) initially identified the following benefit areas and metrics shown in Table 1, below.

Table 1: Initial Identification of MBESS Benefit Areas and Metrics

Benefit	Description	Criteria and Metrics	Desired Targets
Safety	This project is not expected to reduce any existing safety risk. However, this project should comply with existing safety policies and regulations, including transportation, fire, and electrical safety, and not result in safety violations or safety incidents. Additionally, elimination of diesel exhaust emissions providers cleaner air for all to breathe, improving community health.	• Confirm compliance with the following safety-related policies and regulations: • Transportation regulations • Fire safety codes • Electrical safety codes (Rule 21) • Utility interconnection • Local permitting requirements • Other safety-related requirements identified during the project • Investigate and report any safety incidents that occur during the installation, operation, or transportation of the mobile battery.	• The target is 100% compliant and zero injury incidents.
Improved Reliability and Power Quality	Higher reliability occurs by reducing the occurrence and the duration of outages and reducing incidents where	• Track number of hours that mobile battery is connected and available to perform value-added reliability services for equipment	• Successfully black start and power downstream

	power disturbances impact the site's operations. The mobile battery project can provide a level of protection against outages and power disturbances both by being online and available (i.e. as an insurance policy, like an uninterruptible power supply) and by actual mitigation of the impact of an outage or power disturbance (i.e. providing full or partial backup power during an outage and/or potentially avoiding equipment damage by allowing for a controlled shutdown.)	deemed critical or essential by the customer (i.e. customer would be willing to pay money for some sort of backup protection.) • Track the percentage of time that the battery, while connected, is available to perform reliability services. • Track number of events avoided or mitigated, type and duration of these events, and the operational benefit of avoiding or mitigating the event. • Where feasible, conduct tests to assess battery effectiveness at providing reliability services and track results of the tests.	customer loads demonstrating PSPS outage mitigation.
Improved Performance of the Power System	Improved system operations and performance (i.e., system electrical efficiency) will help reduce electrical losses in the system, such as reductions in resistive losses associated with current flow through the conductors and reductions in transformer electrical losses.	• Track the peak demand seen at the utility connection point without the battery and, based on battery discharge, project the peak demand that would have occurred without the battery. • Track the peak current seen at the utility without the battery and, based on battery discharge, project the peak current that would have occurred without the battery.	• Visible reduction in circuit loading and current when using MBESS
Lower Greenhouse Gas (GHG) Emissions	Battery storage can help reduce electrical system losses, which in turn will help reduce the need for electric generation, especially from fossil fueled "peaker" plants. Less generation means fewer GHGs. Additionally, infrastructure such as a battery can store electrically from renewable or other low-emission sources and offset	• Demonstrate the difference in CO_2 emissions from grid power produced during high renewable times and low renewable times. • Identify GHG reductions that deployment of a MBESS can support	• Demonstrate GHG reduction from use of MBESS

	consumption during periods where higher-emission sources would be required, also reducing overall GHG emissions.		
Lower Operating Costs and More Efficient Use of Customer Monies	Customers can see lower costs on their utility bill through peak demand reduction and shifting utility-delivered consumption to lower-cost time periods. Furthermore, reductions in peak load can defer utility infrastructure investments, ultimately mitigating potential rate increases. The project can reduce customer bills through improvement of load factor and reduction of the peak load requirement as well as shifting load to lower cost time periods. Additionally, a reduction in peak load on constrained circuits can lead to deferral of certain capital expenses needed to upgrade distribution infrastructure (though these benefits and costs are very circuit specific).	• Track customer load profile at the utility connection point with the battery and, based on battery discharge, project the load profile that would have occurred without the battery. • Provide an annual bill estimate for both profiles to estimate customer bill savings. • Track the peak demand seen at the utility connection point with the battery and, based on battery discharge, project the peak demand that would have occurred without the battery. • Desired target: Reduce customer energy bill charges through MBESS deployment. Demonstrate circuit peak reduction to demonstrate MBESS use to facilitate grid capital infrastructure deferrals.	• Reduce customer energy bill charges through MBESS deployment. • Demonstrate circuit peak reduction to demonstrate MBESS use to facilitate grid capital infrastructure deferrals.
Economic Development	A secure source of low-cost, high-quality, reliable electric power is essential to economic development and to retain and attract businesses in California. Potential energy and cost savings from avoided procurement and generation costs, peak load reduction and customer bill savings can contribute to economic attractiveness.	• Reduce business cost with energy bill savings and increased reliability	• Visible customer energy cost savings through peak shaving and improved reliability for businesses in the HFTD / PSPS-prone areas.

Disadvantaged Communities (DACs)	The CPUC has encouraged EPIC program administrators to seek projects that benefit disadvantaged communities, including rethinking the location of clean energy technologies to benefit burdened communities. Furthermore, specific project benefits may have direct benefit to the local community (i.e. reduced source emissions when the source is physically located in the disadvantaged community, such as using a mobile battery instead of a diesel generator; GHG emission reductions due to electrical savings are attributed to the generation source, which may not be in the disadvantaged community).	• The project can operate in a disadvantaged community and show investment in these communities. The project may achieve GHG benefits that support state goals and may reduce emissions from sources located within the disadvantaged community.	• Demonstrate reduction in GHGs emitted by MGBW through deployment of a MBESS in their operations and reduction in generator runtime hours when MBESS is deployed for resiliency purposes.
Incremental Benefits of a Mobile Solution	A MBESS solution will accrue incremental and stacked benefits by being rotated through a variety of sites, minimizing MBESS idle time and providing a variety of benefits to multiple customers, including SDG&E. Incremental costs for a mobile battery solution include up-front equipment costs, up-front setup and administrative costs, transportation costs, and incremental operations and maintenance costs. The project can achieve incremental benefits in asset utilization and accrue incremental benefits. The incremental benefits can be compared to incremental	• Track the number of operating hours at the primary site and number of operating hours at the secondary site and report the increase in utilization associated with the mobile solution. • Estimate the cost benefit of the increased asset utilization. • Track the incremental benefits achieved with the mobile battery at secondary sites. • Track the incremental costs associated with a mobile battery. • Evaluate an incremental return on investment (ROI) by considering incremental benefits and incremental costs.	• Increased ROI of the MBESS by semi-permanent deployment in multiple locations.

	costs to determine a return on investment for the mobile solution.		

6.2 Description of Pre-Commercial Demonstration

6.2.1 Location

SDG&E initially planned to deploy the MBESS for Module 1 at the Port of San Diego Cruise Ship Terminal to demonstrate the above-mentioned benefits shown in Table 1. As a consequence of site negotiations, the Cruise Ship Terminal was determined to not be a viable test site within the timeframe of the EPIC-3 cycle. The SDG&E team then expanded the search to sites which allowed for originally intended use case testing as closely as possible. In the expanded search, SDG&E considered additional sites of the following type:

- Port / marine duty with varying site baseloads due to ships cold ironing while in port.
- Local higher educational institutions with variable site loads due to events
- Existing / in-progress community microgrid projects
- PSPS backup / support functions
- Substation and grid infrastructure construction support

Ultimately, two new sites were selected which allowed SDG&E to test various use cases as originally intended, MGBW and CCM, a site which provided a different set of use cases to expand the MBESS stacked benefits.

6.2.1.1 Marine Group Boat Works

MGBW is a full-service marine vessel hauling, refitting, repair and construction facility in Chula Vista, CA. MGBW embraces the importance of preserving the environment and has a longstanding track record of green initiatives which allow them to stay on the forefront of conservation for both their community and industry. These initiatives include:

- installation of a curbed stormwater drain which captures and monitors stormwater discharge to be clear of hazardous materials
- adherence to Port of San Diego regulations and guidelines for removing vessels from the bay before major maintenance and repair work is completed
- installation of solar PV at their National City location
- Use of electric vehicles and electric forklifts for local errands and boat yard work

MGBW staff were excited to engage with SDG&E on this demonstration project and were extremely accommodating to the test team, providing space to deploy equipment, tenant coordination and outage notification and information on historical electrical usage and boat services performed.

From an electrical infrastructure and loading perspective, this site proved to be an ideal test site to deploy the MBESS and test its grid paralleling functions. The site receives their main SDG&E service in the middle of the boat yard, with a dedicated 12kV/480V stepdown transformer. From there, the service feeds two main meters, one for main facility operations and the other for shore power and construction power. There is another 240V/120V transformer and meter fed from the main service entrance, but the load on that meter is minimal.

Daily construction activities such as welding, grinding, cutting, pumping, and lifting as well as "cold ironing" (plugging in ships when in port) provide an electricity usage profile which is highly variable – with high demand peaks during normal work hours of 7:30am – 4:00pm and a highly variable baseload depending upon the number of ships plugged in and work being performed.

The MBESS was ultimately connected to the 480V side of the site transformer and functioned in front (FtM) of the existing site meters due to contracting and liability issues and performed its functions on behalf of SDG&E's existing grid. While the customer's existing bills remained the same with this configuration, potential behind the meter (BtM) savings were also simulated and presented to the customer as to the potential monetary benefits of installing a MBESS behind their existing meters.

6.2.1.2 Cameron Corners Microgrid

As part of its ongoing efforts to reduce wildfire risk and the impact of Public Safety Power Shutoffs (PSPS) during adverse weather conditions, SDG&E is undergrounding critical customers to reduce susceptibility to high winds, installing infrastructure to facilitate the connection of alternate generation and, in some cases, installing full microgrids. CCM is a prime example of all the above activities and a perfect testbed for interconnecting a MBESS, supporting generators and carrying critical downstream loads in a simulated PSPS. The full CCM consists of solar photo-voltaic (PV) panels and permanent energy storage, allowing several key community facilities, including a school, library, health clinic, telecommunications hub, fire station and gas station to remain powered during a PSPS. However, for this test it served as an available, managed site with which to test MBESS connection and is typical of the kind of infrastructure upgrades around SDG&E service territory which would allow for quick connection of backup generation sources.

MBESS testing at CCM focused on demonstrating the blackstart and islanding capabilities of the demonstration unit, not only bringing up downstream load after an outage, but also the unit's ability to function in coordination with diesel generators that are more typically used to provide temporary power to a grid circuit after an outage.

6.2.2 Use Cases

To effectively demonstrate the stacked benefits of this MBESS, grid-paralleling and islanded mode use cases were executed as part of this project. Table 2 describes all the original use cases demonstrated as part of this EPIC demonstration project.

Table 2: Initial MBESS Use Cases

Use Case	Grid Paralleling / Islanding	Description
Safety	Both	MBESS is able to completely shut down after engaging the emergency stop (E-Stop) button. This function promotes overall site safety. MBESS operation is also significantly quieter and cleaner than operation of equivalent diesel generators, allowing for clearer communication and air to breathe.
Load Factor Correction	Paralleling	Sites with poor load factor, high demand peaks and relatively low baseload can benefit from strategic reduction of momentary high demand peaks, thereby improving load factor and strain on the grid.
Load Smoothing	Paralleling	The MBESS will control the rate of change of customer loads reducing strain on grid infrastructure.
Demand Peak Shaving	Paralleling	The MBESS will place a cap on site peak loads, reducing overall demand required from the utility. Peak shaving can be deployed to remove momentary spikes in demand or limit demand to a preset level during strategic times (e.g. TOU peak periods)
Demand Response	Paralleling	Discharging the MBESS to the grid can mimic traditional demand response programs, without interrupting the customer's operations. Pre-set amounts of capacity can automatically be dispatched on strategic circuits during peak congestion times.
Deferral of utility infrastructure investments	Paralleling	Strategic MBESS deployment can add temporary capacity to load constrained circuits while more permanent infrastructure upgrades are planned and constructed. Similarly, MBESS deployment can be strategically deployed to eliminate the need for circuit infrastructure upgrades, if driven by specific load peaks.
Load Blackstart	Islanded	When attached to a downstream load, the MBESS can blackstart loads of appropriate size without the need of additional generating resources.

6.2.3 Equipment Requirements

The equipment used in this EPIC demonstration project supported use of a large MBESS, a 362kW / 1499kWh lithium-ion battery securely mounted to a trailer. Table 3 outlines the equipment requirements for the MBESS deployment as part of this EPIC demonstration.

Table 3: MBESS Equipment Requirements

Equipment	Requirements
MBESS	Battery: • 362kW/1499kWh Capacity • UL 1642 Compliant Lithium Ion Cells • Closed-loop onboard thermal management system • NEMA 3R / IP66 Enclosure Inverter: • 86A Max Continuous Output Current • 860-960V DC Input Voltage Range • 360-555V AC Output Voltage Range • 60Hz • 3 phase, 3-Wire Site Controller • Modbus TCP/DNP3/Rest API Trailer • 48' Aluminum Gooseneck Trailer • (3) Emergency Stop Buttons • 600V / 800A NEMA 3R AC Disconnect and Generator Tap Box • Grounding Loop
Site Meter	Meter – provides reference voltage and current to MBESS, and is necessary for grid-paralleling functions • Pre-approved meter from MBESS manufacturer • Ethernet Port for communication with site controller
Transformer	A Transformer will be needed if the MBESS is connected to any other voltage than 480V 3phase. For this project, a

Equipment	Requirements
	12kV/480V 3 phase Delta/Wye Grounded Transformer was used to connect the MBESS to the grid at 12kV.
Potential Transformers (PTs)	While the MBESS Site meter needed reference voltage from 3 phases and ground, the meter was able to handle 480V, so no PTs were needed. Reference voltage at 480V was fed through a 20A breaker directly to the ports on the back of the meter.
Current Transformers (CTs)	The MBESS site meter required a CT around each power phase. CTs used had a 1000:5 turndown ratio, which kept current reference in line with Site Meter specifications.
I-Line Panels	1200A rated I-Line panels with camlocks were necessary during this test deployment to split the 480V power coming from the low side of the transformer to the MBESS camlocks via a 600A breaker, to provide reference voltage for the site meter (20A breaker) and to power a 30A Mill Panel (30A breaker) for site power.
Mill Panel	A 30A Mill Panel was used to step down 480V 3 phase power to single phase 120 to provide power to the site meter, computers, printers, etc.
Controller	A gateway was used as a controller in order to send commands to the battery and change modes of operation.

6.2.4 Software Requirements

The MBESS came equipped with its own interface software, providing both local access and web-based limited control but needed a gateway in order to have full programming control over the battery. This software was also capable of over-the-air updates, and depending upon desired functionality, new modes of operating, such as microgrid control, could be remotely unlocked as needed.

6.2.5 Supporting SDG&E Infrastructure and Data Requirements

The MBESS in this EPIC project was connected in both grid-paralleled and islanded modes, so SDG&E meter and SCADA data was crucial in validating proper operation of the unit.

When grid-paralleled at MGBW, the MBESS was connected in front of the existing site meters, so site meter data was obtained to verify loads seen by the site meter and MBESS. Additionally, substation circuit loading data was obtained to observe any visible drops from MBESS deployment.

When deployed at the CCM, the MBESS setup was connected to the existing infrastructure already in place, including terminators, Trayer switches and transformers. Through operating positions of the Trayer switch, downstream loads were able to be disconnected from the larger grid and switched over to demonstrate the black start capabilities of the MBESS.

6.2.6 Customer Acceptance Testing

Upon delivery of the MBESS unit, SDG&E performed a thorough, multi-day acceptance test of the equipment received at its Skills Training Facility located in San Diego, CA. This equipment was set up as shown in the following one-line diagram, including a grounding transformer and load bank to provide necessary MBESS grounding and simulate loads on the battery, respectively:

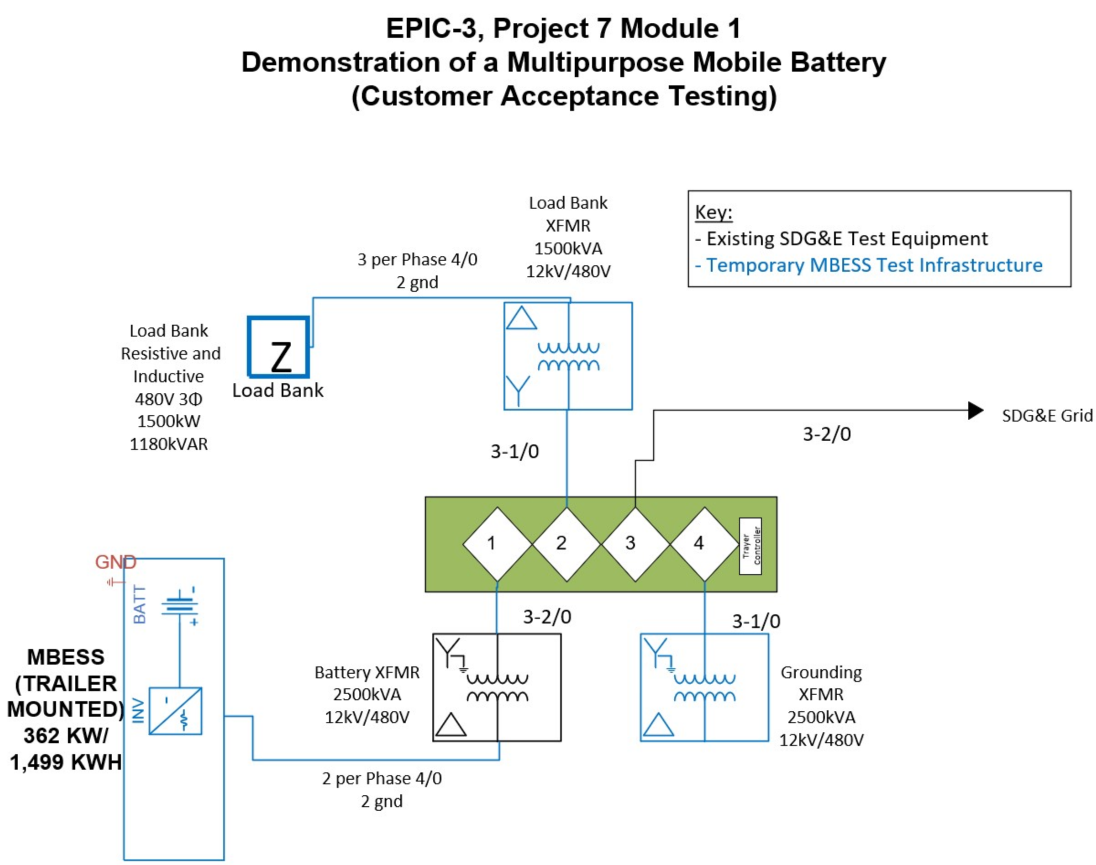

Figure 1: MBESS Customer Acceptance Testing One Line Diagram

The MBESS unit was then taken through the Customer Acceptance tests listed in Table 4.

Table 4: MBESS Customer Acceptance Test Results

Test No.	Test	Expected Results	Pass/Fail
1.	Anti-islanding Mode – Standby	Inverter trips offline when grid power not detected	Pass
2.	Anti-islanding Mode – Parallel – Charging	System will not island and PCS will disconnect per IEEE 1547 AC Breakers open	Pass
3.	Anti-islanding Mode – Parallel – Discharging	System will not island and PCS will disconnect per IEEE 1547	Pass
4.	Parallel Mode – Local	Verify MBESS runs with parallel mode enabled	Pass
5.	Parallel Mode Constant Real Power – Local – Charging	Verify MBESS runs with parallel mode enabled	Pass
6.	Parallel Mode – Constant Reactive Power – Local	Verify MBESS runs with parallel mode enabled	Pass
7.	Parallel Mode – Four Quadrant Test	Verify MBESS reacts in all quadrants to specific setpoints	Pass
8.	Parallel Mode – Target State of Energization (SOE) Charge – Local	Target SOE Mode Enabled PCS to charge at -362kW to target SOE	Pass
9.	Parallel Mode – Target SOE Discharge – Local	PCS to discharge at 362 kW to Target SOE	Pass
10.	Island Mode – Blackstart Enabled	First set of tests: Load bank at 300kW, 200kW, 100kW, 0kW, 200kW Second set: 181kW @ PF=0.5, 363kW @ PF = 0.84, 543kW @ PF = 0.77	Pass
11.	Emergency Stop (E-Stop)	Verified all E-stops operate as intended	Pass

Test No.	Test	Expected Results	Pass/Fail
12.	Uninterruptible Power Supply (UPS)	Verified UPS operates as intended after loss of power	Pass
13.	Human Machine Interface (HMI) Customer Login and Command Operation	Ensured successful customer login and command operation	Pass

Tests which required a site meter for voltage and current reference were unable to be performed at this time, as a manufacturer's approved site meter was unavailable at the initial check out.

6.2.7 Test System Design

Various testing systems were used to support the MBESS deployment and confirm data gathered by the Site Controller.

To provide site meter measurements to the MBESS site controller, a power quality and revenue meter (PQ meter) was installed as part of this test. Current transformers (CTs) were connected around each of the three phase 480V lugs in the site transformer (Figure 2) to monitor net grid-facing current between the MGBW loads and MBESS charge/discharge. Leads on each of the three 480V phases and ground were also fed into the PQ meter to provide reference voltage for the MBESS and site controller. The PQ meter was then connected to the MBESS site controller via an ethernet cable.

Figure 2: MBESS Connection to MGBW Transformer

As a double check on voltage, current and other power quality parameters seen by the site meter, SDG&E connected a portable PQ Meter to the same transformer voltage lugs and placed the CTs around the same cables to confirm current flow in and out of the system. The entire test setup can be seen in Figure 3.

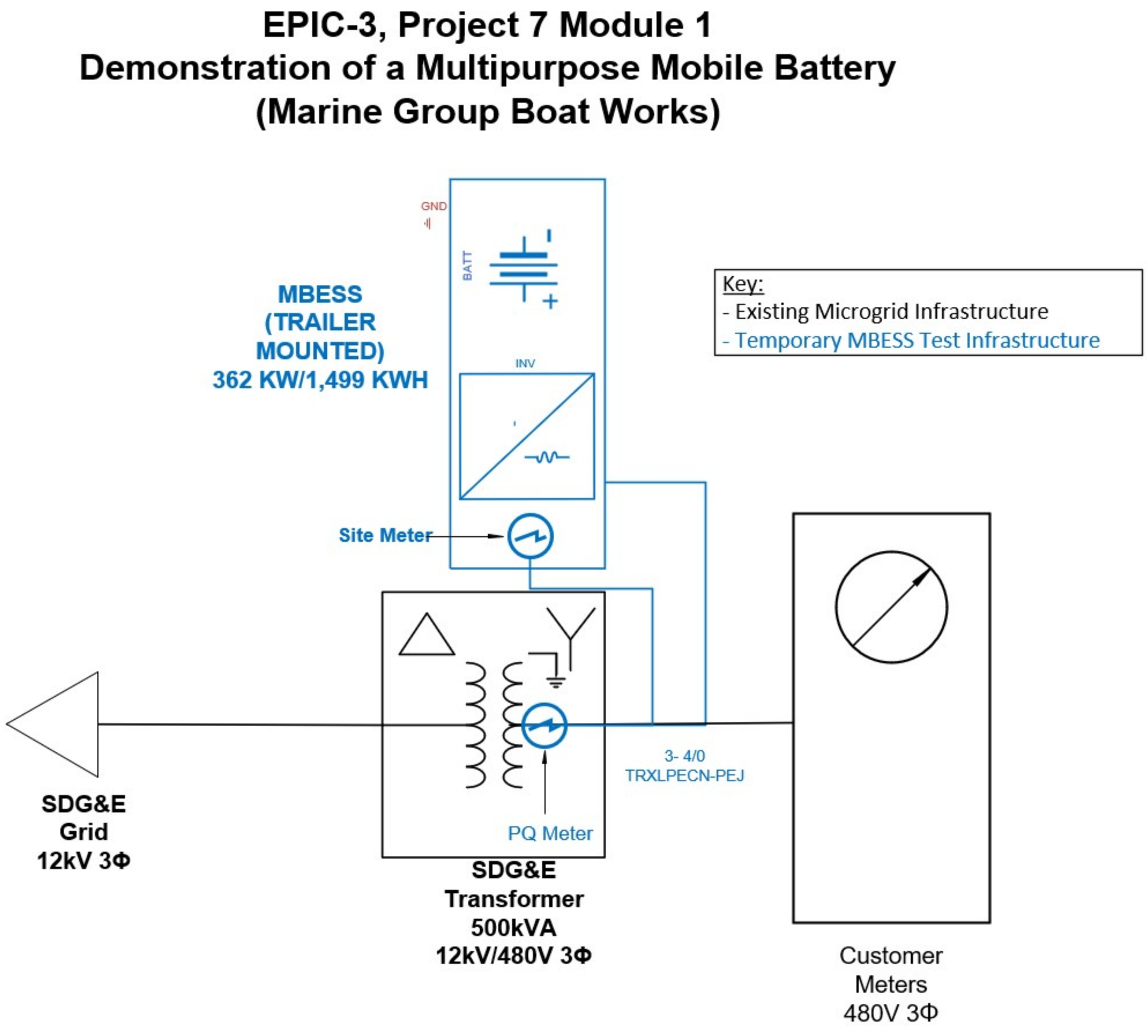

Figure 3: Marine Group Boat Works One Line Diagram

SDG&E customer site data was also obtained for the testing week to verify the loads seen by both the Site Meter/Controller and the PQ meter.

Substation circuit loading data (one second intervals) was also used to verify the MBESS's impact on circuit loading.

At Cameron Corners, PQ meters as well as data gathered from the MBESS site controller were used to verify operation of the MBESS, associated generators and site loads. Substation data (one-minute intervals) were used to verify the MBESS's impact on circuit loading. The entire system setup for the MBESS deployment at CCM can be seen in Figure 4.

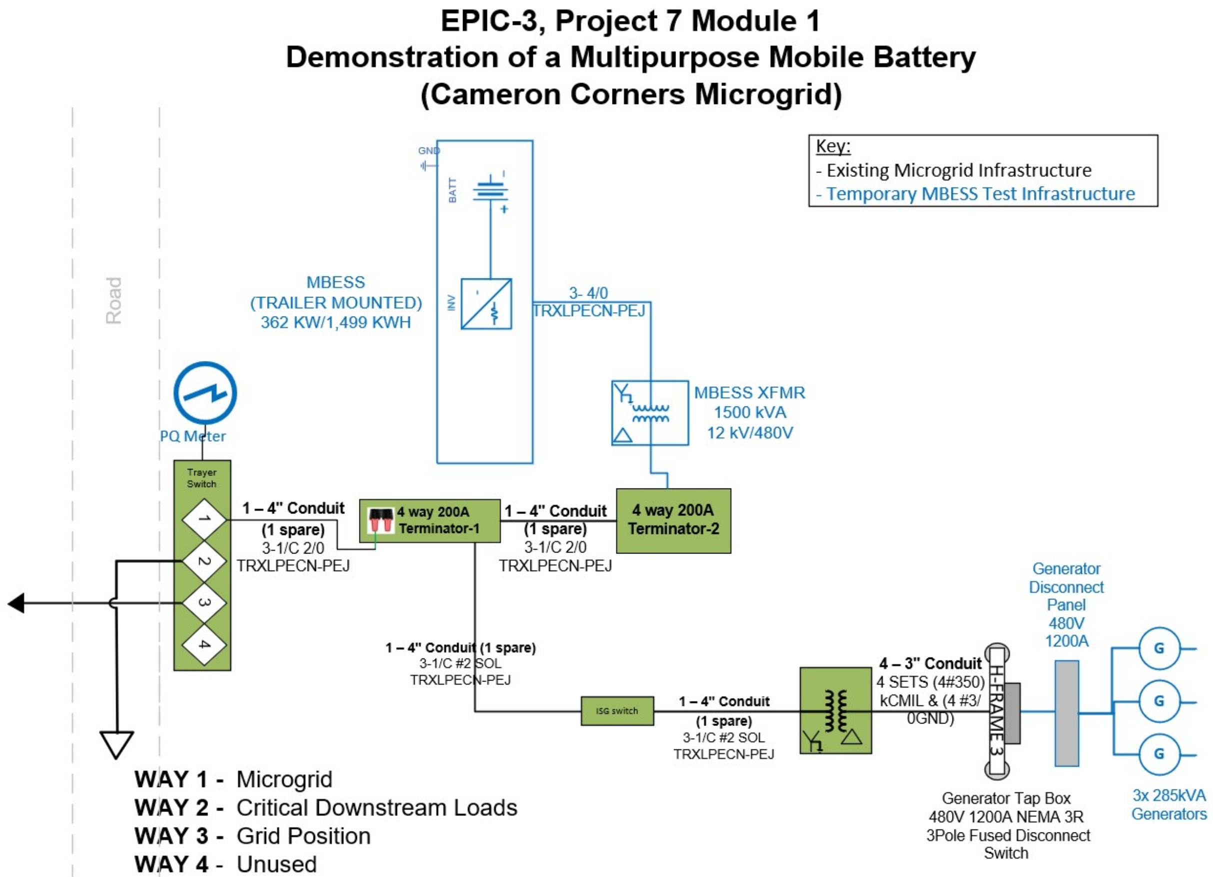

Figure 4: Cameron Corners Microgrid One Line Diagram

6.2.8 Updated Metrics

After selecting the MBESS site and deploying the equipment, the following changes listed in Table 5 were made to the updated metrics and benefits for the project to more accurately capture potential benefits from the MBESS deployment.

Table 5: Updated MBESS Metrics and Benefits

Benefit	Description	Criteria and Metrics	Desired Targets
Safety	Use of a MBESS instead of traditional mobile diesel generators can improve job site safety by reducing the risk, however unlikely, of a fuel spill and by	• Decrease the potential for a diesel fuel spill through use of a MBESS rather than traditional diesel generators	• Demonstrate that a MBESS can perform the function of a diesel generator so on-site fuel storage can be reduced

Benefit	Description	Criteria and Metrics	Desired Targets
	decreasing ambient noise allowing for clearer job site communication.	• Calculate reduction in job site noise pollution by using a MBESS instead of diesel generators	• Calculate a meaningful decrease in job site noise pollution
Improved Reliability and Power Quality	Currently diesel generators provide an adequate solution for SDG&E when providing grid support during emergencies. However, because of their emissions, they are limited to emergency functions only. A MBESS can provide emergency backup, supporting reliability, but also can support broader grid reliability through peak shaving, load smoothing, voltage and frequency regulation, and by prolonging life of grid equipment.	• Ensure that MBESS can act as a backup power source, capable of black starting downstream loads like a diesel generator. • Demonstrate peak shaving and load smoothing abilities • Calculate increase on grid infrastructure lifespan based on circuit amperage reductions and corresponding equipment temperature reductions • Calculate dollar value of grid equipment lifespan increases • Calculate dollar value of grid / circuit upgrades deferrals	• Successfully black start and power downstream customer loads demonstrating PSPS outage mitigation. • Show peak load shaving capabilities and load smoothing thresholds • Grid equipment lifespan extensions are real and meaningful • Value calculations for lifespan increases and grid infrastructure upgrade deferrals demonstrates value to SDG&E
Improved Performance of the Power System	Improved system operations and performance (i.e., system electrical efficiency) will help reduce electrical losses in the system, such as reductions in resistive losses associated with current flow through the conductors and reductions in transformer electrical losses.	• Calculate the peak current reduction for the MBESS deployment • Determine the percentage of reduction the MBESS is of a full circuit loading	• Visible reduction in circuit loading and current when using MBESS
Lower Greenhouse	Using a MBESS instead of diesel generators will provide reductions in	• Calculate the diesel fuel savings (gallons	• Show a reduction in diesel fuel

Benefit	Description	Criteria and Metrics	Desired Targets
Gas (GHG) Emissions	localized emissions at sites needing grid resiliency.	and cost) associated with a switch to MBESS • Convert diesel savings to yearly metric tons of CO_2e • Calculate CO_2e reduction value on California's Cap and Trade market.	consumption for grid resiliency support. • Determine value of emissions reductions on California's Cap and Trade market.
Lower Operating Costs and More Efficient Use of Customer Monies	Using a MBESS to support grid upgrade deferrals provides real value to SDG&E, money that would otherwise be spent on infrastructure upgrades. Because of the mobile nature of a MBESS, strategic deployment based on SDG&E's grid needs assessment can push out capital upgrades, which would save or defer use of ratepayer dollars. This value can be calculated and can be factored into the lifecycle cost of a MBESS for SDG&E. Ideally, it could make MBESS a more financially advantageous investment for SDG&E to meet its grid resiliency needs than the more traditional diesel generators.	• Calculate the 10 year lifecycle cost of a MBESS purchase vs. a diesel generator rental model, currently employed by SDG&E. Include upfront costs of the MBESS purchase, ongoing and yearly costs and potential revenue streams from other MBESS functions such as grid upgrade deferrals and CAISO market functions.	• Demonstrate a greater ROI for a MBESS vs. a diesel generator • Demonstrate positive value from partial participation in CAISO market functions.
Economic Development	Should SDG&E choose to procure additional MBESS to support grid resiliency and grid infrastructure upgrade deferrals, this will generate a local market for these units. Not only will it draw awareness to such a product and its flexibility, but also it will attract jobs associated with the supply, setup, operation and maintenance of the MBESS	• Calculate the number of MBESS needed to fully defer SDG&E's planned grid upgrades between 2021-2030. • Calculate the value of local market investment required to procure MBESS for	• Generate a significant local market investment in MBESS technology

Benefit	Description	Criteria and Metrics	Desired Targets
		grid upgrade deferrals.	
Disadvantaged Communities (DACs)	The CPUC has encouraged EPIC program administrators to seek projects that benefit disadvantaged communities, including rethinking the location of clean energy technologies to benefit burdened communities. Furthermore, specific project benefits may have direct benefit to the local community (i.e. reduced source emissions when the source is physically located in the disadvantaged community, such as using a mobile battery instead of a diesel generator; GHG emission reductions due to electrical savings are attributed to the generation source, which may not be in the disadvantaged community).	• The project can operate in a disadvantaged community and show investment in these communities. The project may achieve GHG benefits that support state goals and may reduce emissions from sources located within the disadvantaged community.	• Demonstrate SDG&E's increased ability to support GHG reductions in DACs through deployment of a MBESS in their operations and reduction in generator runtime hours when MBESS is deployed for resiliency purposes.
Incremental Benefits of a Mobile Solution	When compared to the traditional resiliency solution (a diesel generator), a MBESS solution will accrue incremental and stacked benefits by being relocated to a variety of sites and perform a variety of functions, minimizing MBESS idle time and providing a variety of benefits to SDG&E. ROI and long-term benefits have been quantified in the other benefit areas above.	• Demonstrate increased flexibility in MBESS deployment vs. traditional diesel generators • Evaluate additional potential value generation opportunities for a MBESS vs. traditional diesel generators • Identify any additional benefits associated with using a MBESS over Diesel generators.	• Increased flexibility of deployment • Additional functionality successfully demonstrated by a MBESS • Quantify any additional benefits

6.2.9 Site Acceptance Testing

At MGBW and Cameron Corners MBESS deployments, the system was connected to the existing site switchgear per site interconnection schematics and energized. Readings from test, including the site meter, PQ meter and MBESS site controller were all compared to ensure metering was correctly installed and accurately calibrated.

6.2.10 Test System Integration

The MBESS project was a stand-alone operation at the MGBW site, providing all cabling, switchgear, protection and connectivity for a successful deployment and demonstration. However, at Cameron Corners, the demonstration was able to leverage permanently installed microgrid site infrastructure to connect and power downstream loads. As part of its ongoing efforts to reduce wildfire risk and the impact of PSPS during adverse weather conditions, SDG&E is undergrounding critical customers to reduce susceptibility to high winds, installing infrastructure to facilitate the connection of alternate generation and, in some cases, installing full microgrids. The Cameron Corners Microgrid site is a prime example of all the above activities and a perfect testbed for interconnecting a MBESS, supporting generators and carrying critical downstream loads in a simulated PSPS. This kind of arrangement is typical of the infrastructure upgrades found around SDG&E territory which would allow for quick interconnection of backup generation sources.

6.2.11 Execution of Demonstrations

Table 6 lists pertinent details regarding the execution of the demonstration.

Table 6: MBESS Demonstration Test Activities

Day	Details
MGBW Day 1	• Safety Tailgate • MBESS transported from original commissioning spot to MGBW • MBESS energized and main 480V AC breaker closed to energize communications • Site meter communications with site controller established • Additional test equipment delivered to the site (I-Line & Mill Panels, Cables) • Rotation check performed on the site transformer to prepare for interconnection wiring work on day 2
MGBW Day 2	• Safety Tailgate held to prepare for outage and transformer interconnection • Wiring of power cables, I-Line, Mill Panels, MBESS, CTs and reference voltage leads all set up • Outage Taken • CTs hung on transformer leads, extension plates installed to allow for MBESS interconnection. • Customer power restored • Battery taken out of storage mode, and energized

Day	Details
	• Battery charged in preparation for testing
MGBW Day 3	• Safety Tailgate • System connections set up to allow communication and control of battery • Site meter and power quality meter readings compared • Set up first test: load smoothing. • Testing not performed, as current CTs were installed backwards and provided negative readings. • Battery discharge tests performed; results observed. • System deenergized in preparation for CT polarity to be fixed. • Customer outage taken to swap CT leads • Customer power restored • Site meter readings taken to confirm proper current and power signals
MGBW Day 4	• Safety Tailgate • Battery charged to 80% SOE for days testing • Preparation for days testing. • Battery load smoothing tests performed • Battery peak shaving test performed • Battery zero load test performed • E-Stop Test Performed
MGBW Day 5-8	• Safety Tailgate • Battery charging performed to not set a new site peak. • Site tear down • Customer outage to remove test equipment from site transformer • Power Restored • MBESS and test equipment moved from MGBW to Cameron Corners
CCM Day 1	• Safety Tailgate • MBESS, test equipment, mobile transformer, generators delivered to Cameron Corners and set up in place
CCM Day 2	• Safety Tailgate • MBESS shoefly interconnected (not using permanent microgrid infrastructure) with generators to perform microgrid controller programming and testing
CCM Day 3	• Safety Tailgate • Microgrid controller programming completed

Day	Details
	• Test equipment interconnected into permanent SDG&E microgrid infrastructure behind open Trayer switch (no customer load interconnection)
CCM Day 4	• Safety Tailgate • Behind open Trayer switch, cold load pickup test performed with load bank to pre-test picking up real customer load. • Blackstart sequences of operation and protection settings finalized • Microgrid protection settings programmed into system protection devices for microgrid position of Trayer switch
CCM Day 5	• Safety Tailgate • Grid position on Trayer switch opened, downstream outage taken • Microgrid energized and MBESS issued blackstart command with generators in standby • Downstream loads closed in to be picked up by MBESS. • When battery reached minimum SOE, microgrid controller commanded generators online to carry load while battery charged. When desired SOE reached, MBESS took control of downstream loads again and generators ramped down. • Process continued for 24 hours
CCM Day 6	• Safety Tailgate • Generators and MBESS commanded off • Trayer microgrid position opened causing downstream outage • Trayer grid position is closed, and downstream loads are re-energized. • Test teardown.

6.2.12 Use Case Execution

Table 7 illustrates the execution details performed by the MBESS for each of the use cases.

Table 7: MBESS Use Case Test Results Summary

Use Case	Execution Details
Safety	E-Stop test completed in both grid-parallel and islanding modes
Load Factor Correction	Load factor re-calculated with customer interval data and site meter data while load smoothing, peak shaving and zero load tests were performed.

Use Case	Execution Details
Load Smoothing	Load smoothing tests performed as standalone – smoothing natural customer load, and at prescribed peak levels.
Demand Peak Shaving	Peak shaving tests performed as intended, both at pre-set levels and “zero-load” levels.
Demand Response	MBESS discharge at prescribed levels up to 362kW performed as intended.
Deferral of utility infrastructure investments	Substation test data pulled for duration of peak shaving and load smoothing tests.
Load Blackstart	Downstream loads successfully black started with Mobile Battery

6.2.13 Data Acquisition

In order to determine the performance of the MBESS during use case execution, the data shown in Table 8 was collected.

Table 8: MBESS Test Data Captured

Data Source	Processing Tool(s)	Data Frequency	Data Collected
PQ Meter	Microsoft Excel	1 Sample / Sec	Voltage (V), Current (A), Real Power (kW), Apparent Power (kVA), Reactive Power (kVAR), Frequency (Hz)
MBESS Site Controller	Microsoft Excel Manufacturer Web Interface	Variable Sample Rate	Battery Real Power (kW), Battery Reactive Power (kVAR), Load Real Power (kW), Battery Energy Remaining (kWh), Battery SOE (%), Target Real Power (kW), Target Reactive Power (kVAR), Frequency (Hz), Battery Export Energy (kWh), Battery Import Energy (kWh)
Customer Meter Data	Microsoft Excel	1 Sample / 15 minutes	Customer 15 min Load Data (kWh)

Data Source	Processing Tool(s)	Data Frequency	Data Collected
Substation Loading Data	Microsoft Excel	1 Sample / second	Substation Loading Data Every Second(A)

6.3 Data Analysis

Data from the equipment listed in section 6.2 above was collected and analyzed as shown in Table 9. Results of the analysis are shown in Section 7, below.

Table 9: MBESS Test Data Analysis

Test	Use Cases Supported	Data Used	Test Description
E-Stop	Safety	Battery Discharge Power (W)	Battery discharge power was monitored before and after depressing E-Stop button on MBESS trailer.
Load Smoothing	Load Smoothing	Grid Facing Load (W)	Target Site Load Rate of Change Set in MBESS controller. Grid facing load monitored before and after MBESS placed into Load Smoothing Mode. Rate of change of grid facing load calculated to assess impact of load smoothing
Peak Shaving	Demand Peak Shaving	Grid Facing Load (W)	Target Grid Facing Load set in MBESS controller. Grid facing load monitored before and after MBESS placed into Peak Shaving mode. Grid facing load monitored for compliance to set targets.
Zero Load	Demand Peak Shaving	Grid Facing Load (W)	Target Grid Facing Load set to zero in MBESS controller. Grid facing load monitored before and after MBESS placed into Peak Shaving mode. Grid facing load monitored for compliance to zero net grid facing load.
Battery Charging / Discharging	Demand Response GHG reduction	Grid Facing Load (W)	Battery charge or discharge commands sent at prescribed kW levels. Grid facing load monitored to ensure commensurate load changes are seen.

Test	Use Cases Supported	Data Used	Test Description
Black Start	Load Blackstart	Battery Power (W), Generator Power (W)	Downstream loads closed into battery placed in islanding/grid forming mode. Battery microgrid controller monitored grid frequency and injected current to maintain frequency using mobile generators if load exceeded battery capabilities. Microgrid controller also monitored MBESS SOE to switch to charge mode when minimum SOE reached. Once maximum SOE reached, generators shut off and MBESS continues to carry load as available. Repeat as necessary for 24 hours.

7.0 Project Results

MBESS testing results indicate that functional performance was successful in all benefit areas. Table 10 summarizes the results of each test.

Table 10: MBESS Project Test Results Summary

Test	Use Cases Supported	Pass/Fail	Notes
E-Stop	Safety	Pass	Battery Power drops to zero when E-Stop button depressed.
Load Smoothing	Load Smoothing	Pass	Average site load rate of change post-load smoothing was 52-72% smoother than with no load control. Also, load rate of change control was between 33% (when constrained to 166 W/s) and 152% (when constrained to 50 W/s) of set targets.
Peak Shaving	Demand Peak Shaving Load Factor Correction	Pass	Grid facing load capped at prescribed 200kW target with maximum 1.4% deviation of load target.

Test	Use Cases Supported	Pass/Fail	Notes
Zero Load	Demand Peak Shaving	Pass	Grid facing load capped at prescribed 0kW target with maximum 3000W (~1% of overall load) deviation from load target.
Battery Charging / Discharging	Demand Response GHG reduction	Pass	Battery charges or discharges at prescribed levels, adding to or subtracting from the net site load in the commensurate amount.
Black Start	Load Blackstart	Pass	Battery successfully black started downstream customer loads, microgrid controller successfully started generator spinning reserves to meet increased site loads and handed off control to generators when needing to switch to charging mode.

7.1 Results Discussion

7.1.1 Safety Use Case

A successful E-Stop test (illustrated in Figure 5) contributed to demonstration of a safety benefit when using a MBESS. The project complied with existing safety policies and regulations, including transportation, and did not contribute to any safety incidents. Should a safety issue arise stemming from use of the MBESS, it can be shut down instantaneously.

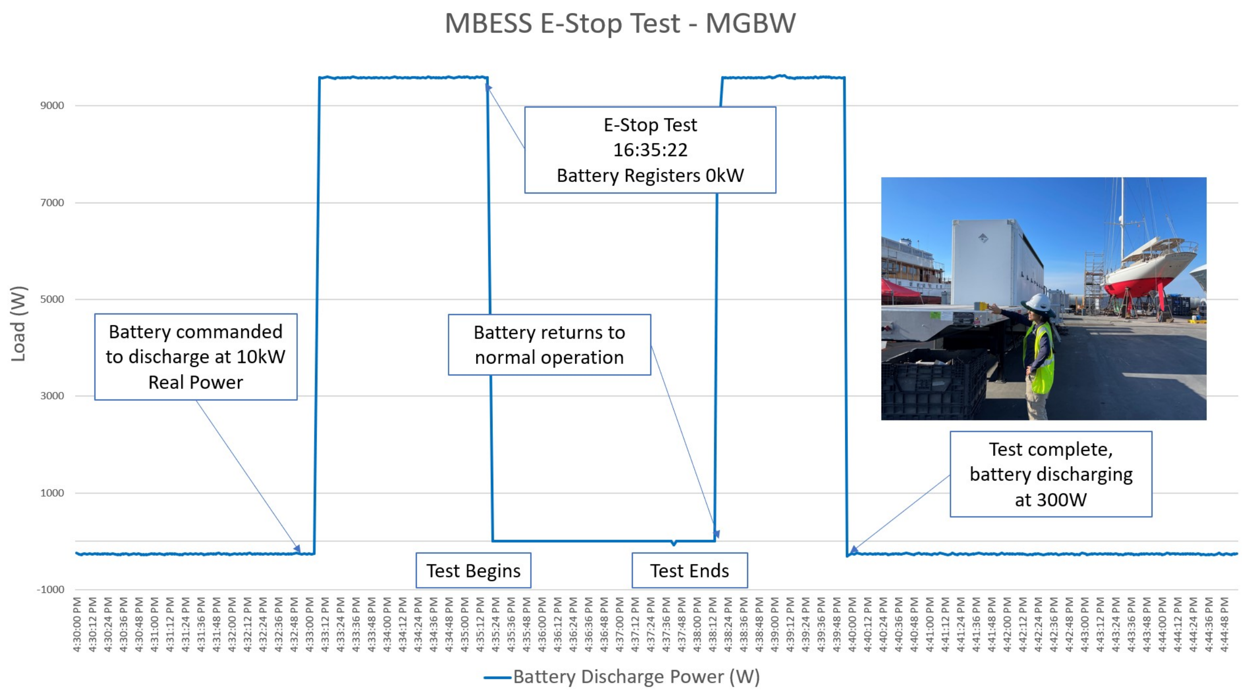

Figure 5: MBESS E-Stop Test Graph

At CCM, when the downstream loads were being carried by the MBESS, it was noticeably quieter than with the generators running, even at idle. Communication and site awareness were increased when operating on MBESS alone.

7.1.2 Load Factor Correction

With the MBESS's ability to peak shave and load smooth, the MBESS can successfully correct a load factor, very close to 1. As seen in figure 6, in the 200kW load smoothing and peak shaving test, the MBESS was able to hold an average peak load of 202,712W, which is 1.4% above the 200,000W target. Using MGBW's hourly meter data obtained during the testing week, the site's native load factor was 76% for that week, well above their historical 20-60% load factor calculated from monthly utility data. In either scenario, the MBESS's ability to correct load factor to 98.6% is a significant improvement for a site with high peak loads and low usage. Deploying a MBESS at customers such as MGBW would benefit SDG&E's FtM distribution infrastructure by providing more consistent loading at the substation level.

7.1.3 Load Smoothing

When connected in parallel to the grid in a FtM configuration, the MBESS can smooth out peaks in loads and control the ramp rates of customer loads as seen by the grid. A specific load smoothing test (Figure 6) was run with the MBESS at MGBW with two different rate of changes specified 166W/s and 50W/s. In comparison to customer load rate of change before the load smoothing test at an average of 462W/s, the MBESS was able to reduce load changes to an average of 220W/s and 50W/s, respectively. This demonstrates an achievable 54-89% in grid-facing load rate of change.

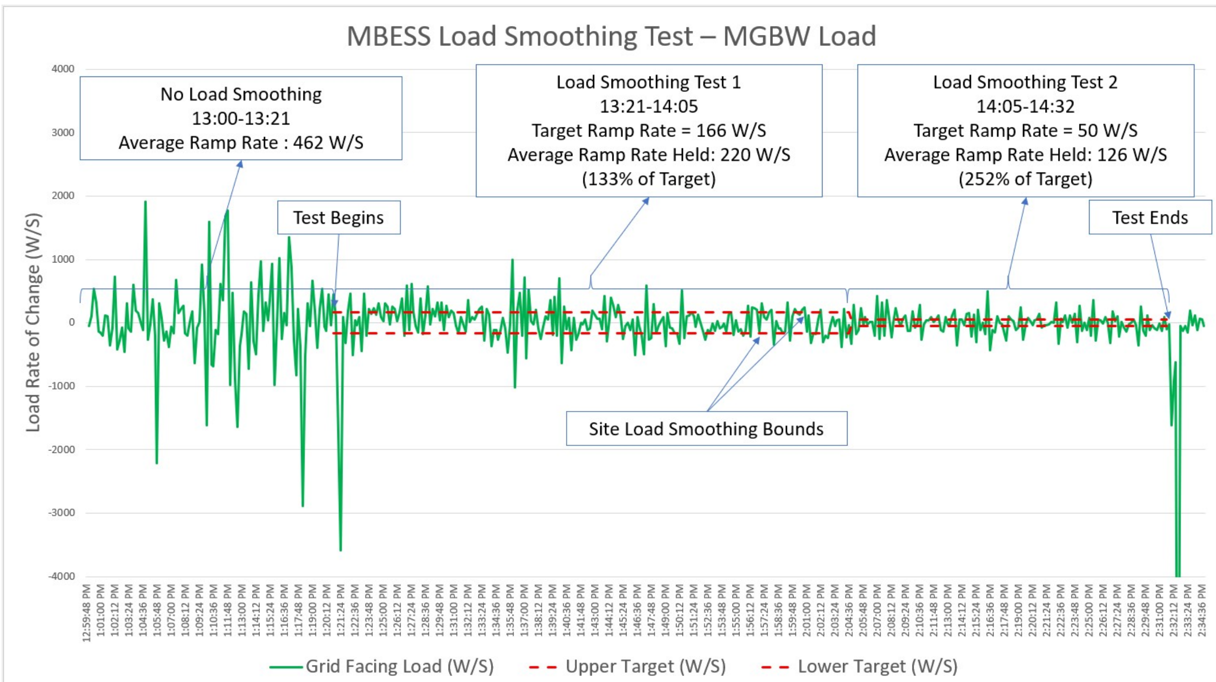

Figure 6: MBESS Load Smoothing Test - MGBW

Similarly, a reduction in ramp rate for grid-facing amps can also be seen during the load smoothing test. Pre-load smoothing test, the average rate of change for grid facing amps was 0.871 amps/sec. However, after implementing the two load smoothing tests, the rate of current change seen at the MGBW transformer dropped by 20% and 12%, respectively, in comparison to the baseline. This data can be seen in Figure 7.

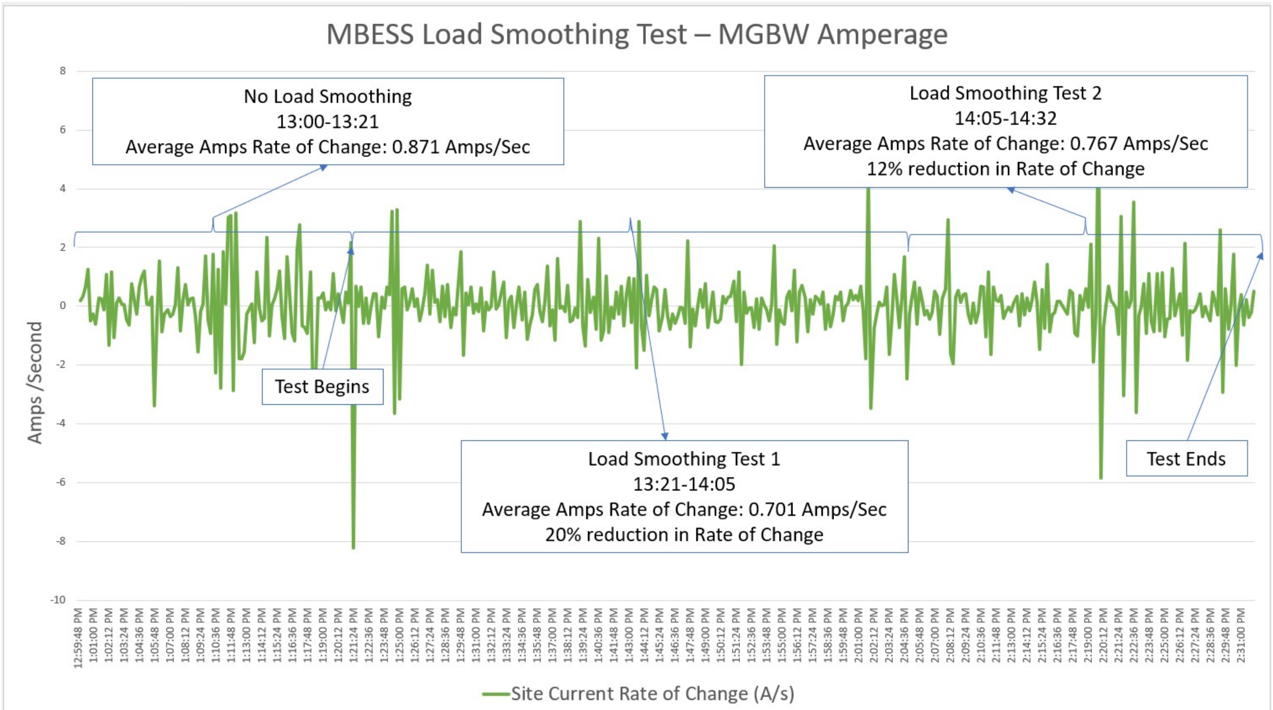

Figure 7: MBESS Load Smoothing Test - MGBW

7.1.4 Demand Peak Shaving

Two demand peak shaving tests were conducted with the MBESS while connected in parallel to the grid at MGBW. The first set a maximum output for the site at 200 kW and the second test set target site load at zero kW, effectively eliminating the load of MGBW from the circuit.

In the 200kW peak shaving test, the MBESS was able to maintain the grid-facing site load within 1.4% of the target, give two different ramp rate parameters, 0 W/s and 5 W/s. You can see this performance in the graph in Figure 8 comparing the site's actual load to the grid facing load.

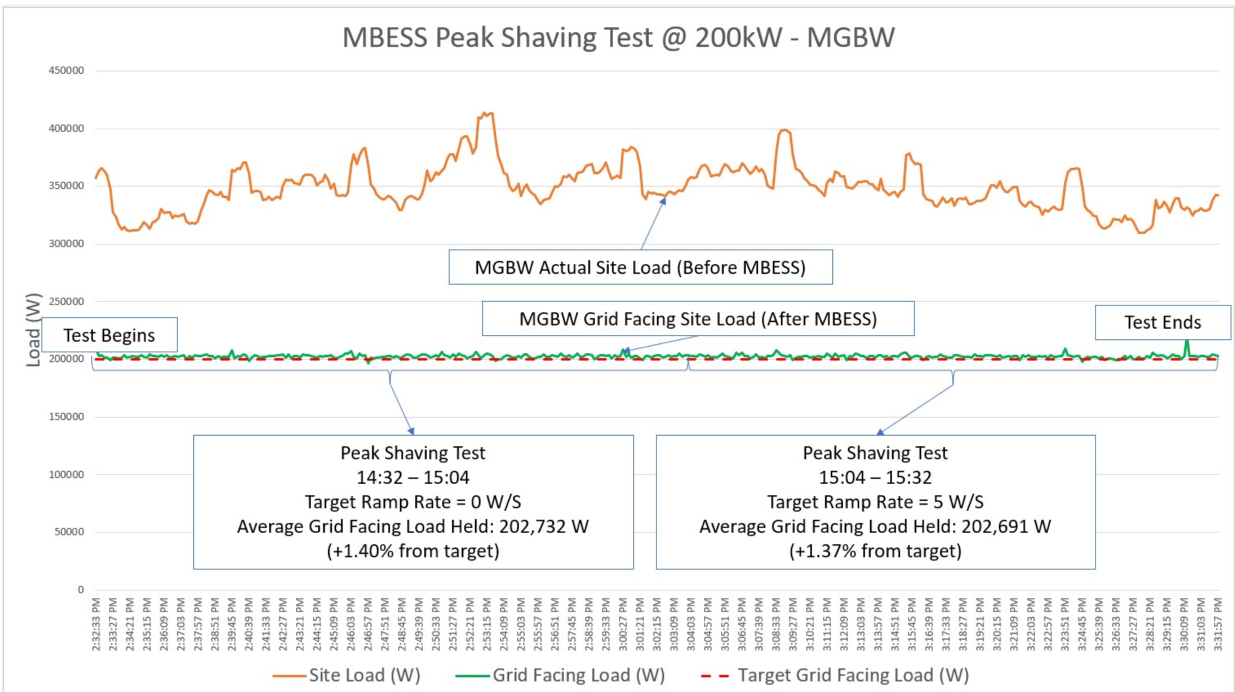

Figure 8: MBESS Peak Shaving Test @ 200kW - MGBW

Similar performance was demonstrated during the zero load test, the ultimate peak shaving, which effectively eliminated the MGBW's load from the corresponding circuit. Through this period, the MBESS was able to maintain a grid facing site load of 3,841W, or approximately 1% of the site's gross load of over 300kW. You can see the performance of this test in Figure 9, whereby grid facing load is all but eliminated. Of note, there are a few peaks in this test where the site load changed too rapidly for the battery discharge to effectively respond, resulting in a few minor peaks in the grid facing load. However, overall performance of the MBESS in this test met expectations.

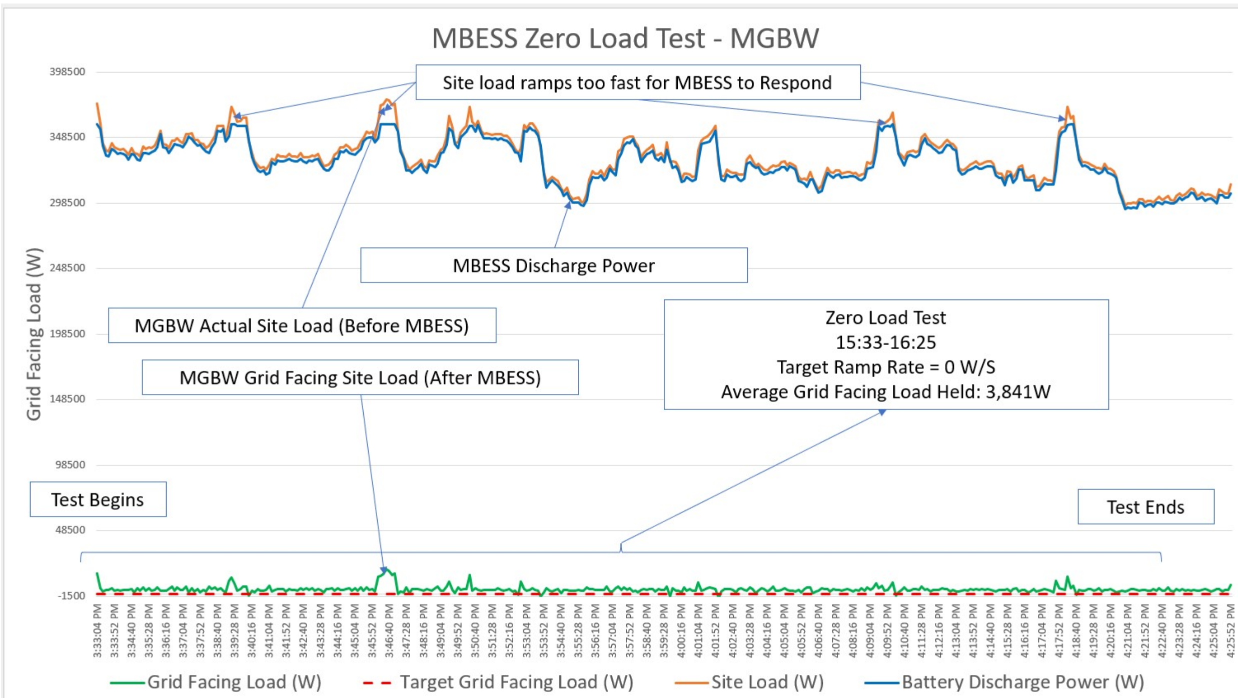

Figure 9: MBESS Zero Load Test - MGBW

To understand the impact on the corresponding substation, amperage and loading data was taken and analyzed prior to and during the time period of the peak shaving tests. Loading and Amperage reductions were seen during both tests with the biggest impacts seen during the zero-load test – a 11% drop in maximum circuit amperage and a 10% reduction in MW seen on the circuit. Figure 10 shows this graphically, plotting both the circuit current (in amps) and circuit loading (in MW).

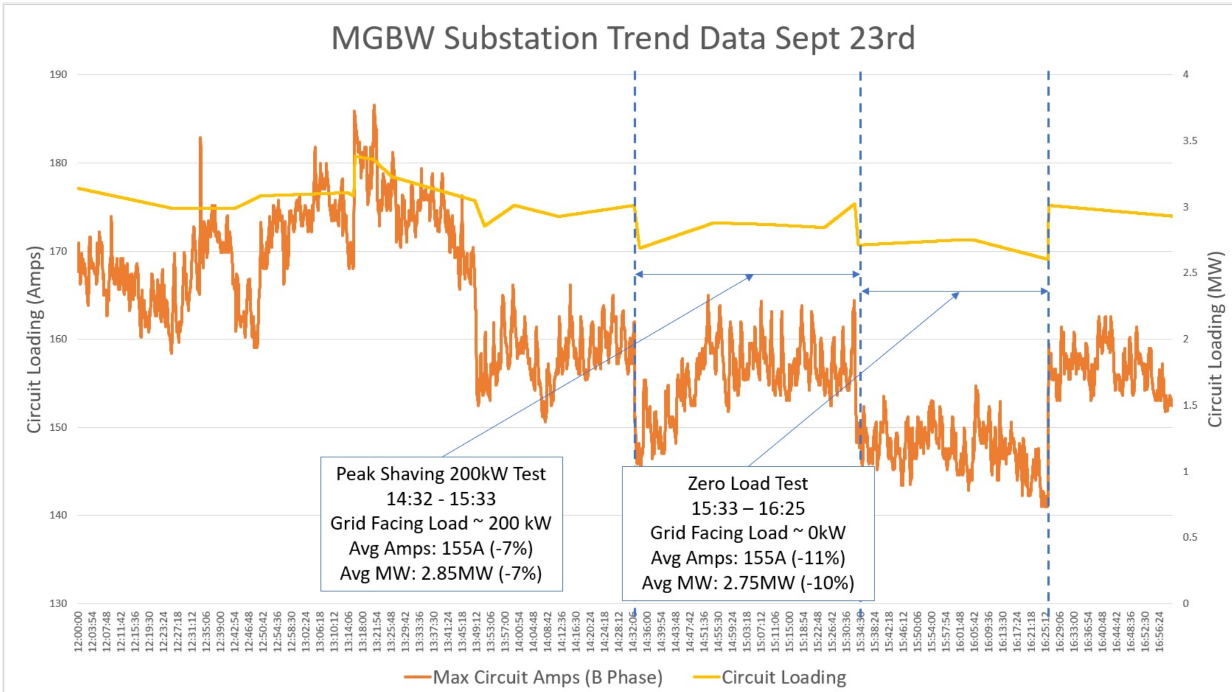

Figure 10: MGBW Substation Trend Data

Reductions in circuit loading were also seen during the Cameron Corners blackstart & island test. To discount any potential contributions from solar PV on the circuit, averages were taken of calculated for circuit current and loading from 6pm- 7am. On average, islanding the Cameron Corners customers reduced circuit current by 5.57 Amps at 12kV or a 10.7% reduction. Circuit loading reductions were commensurate, averaging 0.88MW less on the islanded day, or a reduction of 8.9%. Circuit conditions are shown in the graph in Figure 11.

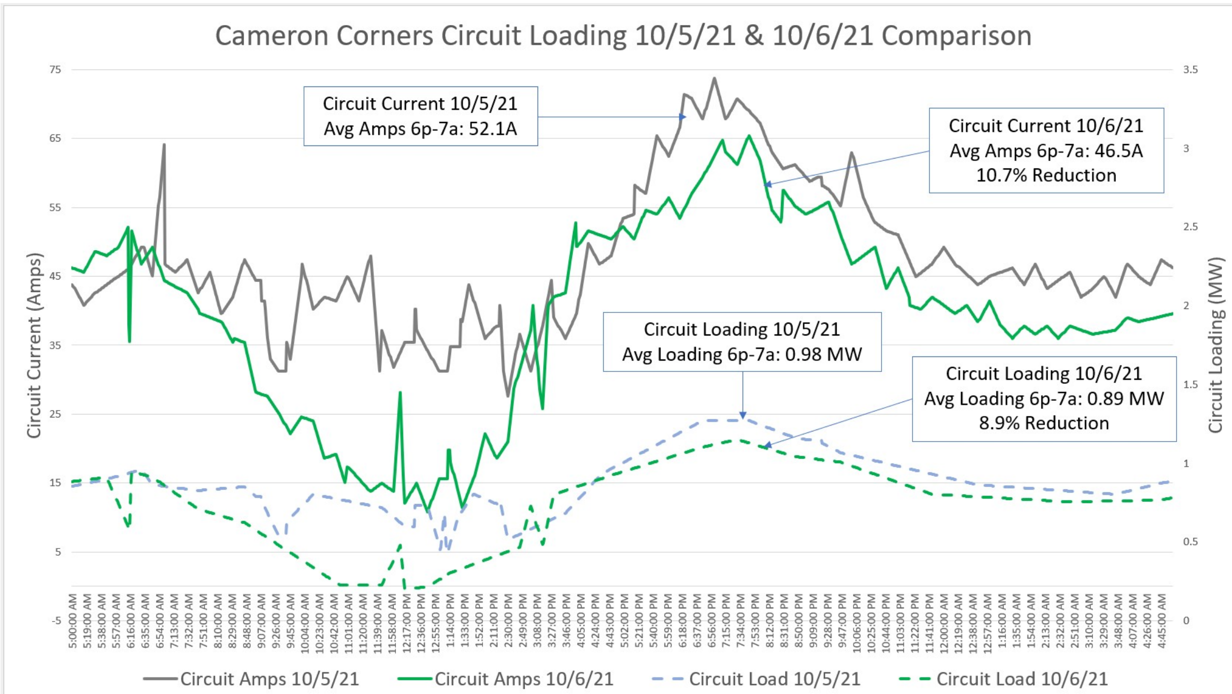

Figure 11: Cameron Corners Circuit Loading Two-Day Comparison

Through the peak shaving and zero load testing, the MBESS demonstrated its ability to participate in the demand response market. Not only is the battery able to reduce and cap site load to a preset level, it is also able to eliminate a site's load from the corresponding circuit. Additionally, as seen in the test in Figure 12, the MBESS can discharge a pre-set amount to the grid, even beyond the site load if needed.

7.1.5 Demand Response

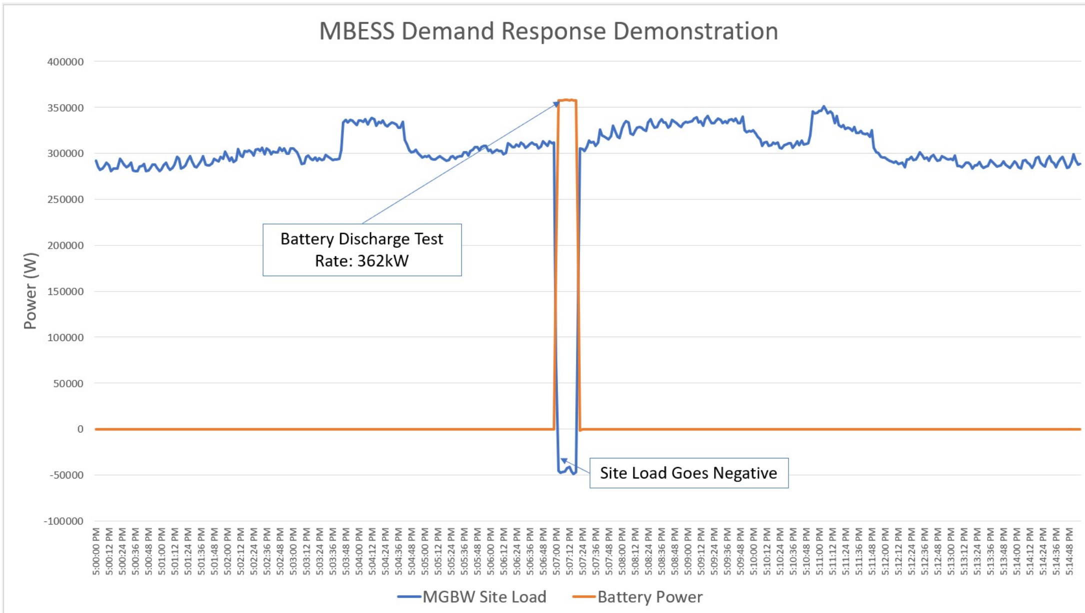

Figure 12: MBESS Demand Response Demonstration

7.1.6 Deferral of Utility Infrastructure Investments

From the testing performed with the MBESS at both MGBW and Cameron Corners, deferral of utility infrastructure investments is possible. From the Zero Load Test, the MBESS reduced circuit loading by any preset amount, up to the maximum discharge capacity of the battery, reducing circuit amps by 10% and circuit loading by 11% in the particular case of the test. The observed circuit loading reduction data observed is in line with the 12kV circuit current reduction a 362kW can provide, approximately 30 Amps. Assuming a 12kV circuit is designed for 500A maximum loading, this is a maximum circuit current reduction of 6%.

Also contributing to the increased life of grid infrastructure, from the Load Smoothing Test, the MBESS was able to smooth out the rate of change of circuit load by 52% and 72% when compared to the original circuit rate of change.

The MBESS blackstart and islanding performance at Cameron Corners demonstrated a key deferral of utility infrastructure investments. In a scenario similar to that at Cameron Corners, SDG&E could prioritize undergrounding of key community loads in PSPS-prone locations, and power them during PSPS season with a MBESS, while a full community resiliency plan is put in place. The mobility of the MBESS allows SDG&E to deploy significantly sooner, as they would with a mobile generator, and carry critical community loads with a zero-emission temporary solution.

7.1.7 Load Blackstart

The MBESS deployment test at Cameron Corners focused on proving the Blackstart use case. Traditionally, synchronous generators (e.g. diesel generators) have been used to black start downstream loads and inverter based generators (e.g. BESS) have struggled to handle black starts due to high inrush current from certain inductive loads. Working with the MBESS manufacturer, the SDG&E team not only successfully black started downstream loads at Cameron Corners, but also autonomously handed off control of grid-forming operations to diesel generators connected in parallel when the battery was completed.

Two methods of black starting downstream loads at Cameron Corners were tested during the MBESS demonstration. The first method, which mirrored SDG&E's existing procedures for black starting loads using synchronous generators, energized the MBESS in island mode before closing in downstream loads via a Trayer switch. The second method, which was recommended by the battery manufacturer, closed in the deenergized downstream loads to the MBESS and then issued the blackstart command, allowing the MBESS to ramp up current until voltage and frequency setpoints were able to be met.

In both cases of black start, the cold load pickup and soft start configurations, the MBESS successfully black started downstream loads of 63kW and 76kW, respectively, within 2 seconds of the load close-in / blackstart command. Test results can be seen in Figure 13. While these load pickups were less than the 300kW rated maximum black start capacity of the MBESS, initial acceptance testing revealed that the MBESS was capable of a load blackstart higher than its rated capacity.

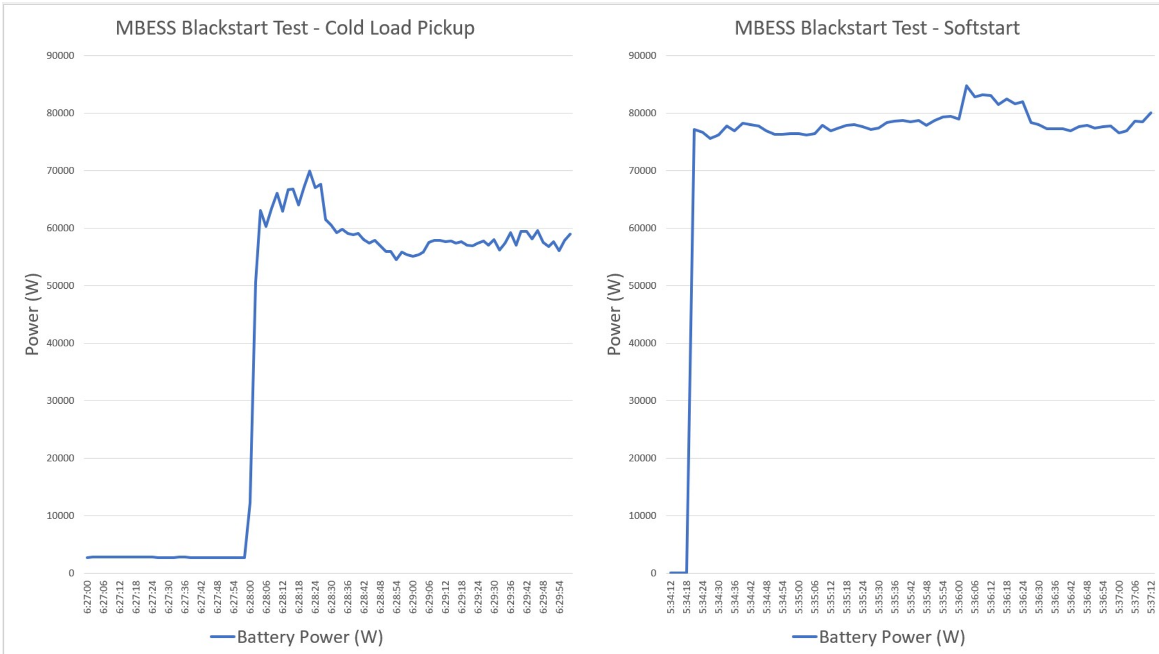

Figure 13: MBESS Blackstart Test Charts

The other important MBESS software which was tested during the 24 hour black start/island test was the microgrid control software which allowed seamless and automated control of the grid-forming duty to be handed off between the MBESS and paralleled diesel generators. After the MBESS's microgrid controller successfully black started the downstream loads, the microgrid ran on battery alone until it reached its minimum (SOE) of 25%. Upon seeing this minimum SOE was reached, the microgrid controller started the diesel generators and used them to carry the downstream loads and charge the battery back up to a target SOE of 90%. Upon reaching the desired SOE, the microgrid controller shut down the generators and proceeded to run the downstream loads on battery only until depleted down to the minimum prescribed SOE.

The microgrid controller also monitored the downstream load on the feeder and was programmed to start a generator as spinning reserve should the downstream load come within 50kW of the rated islanding capacity of the MBESS. This was tested with a load bank (Figure 14) during pretesting but the load on the feeder never exceeded the capacity of the MBESS, so it was never tested with real load.

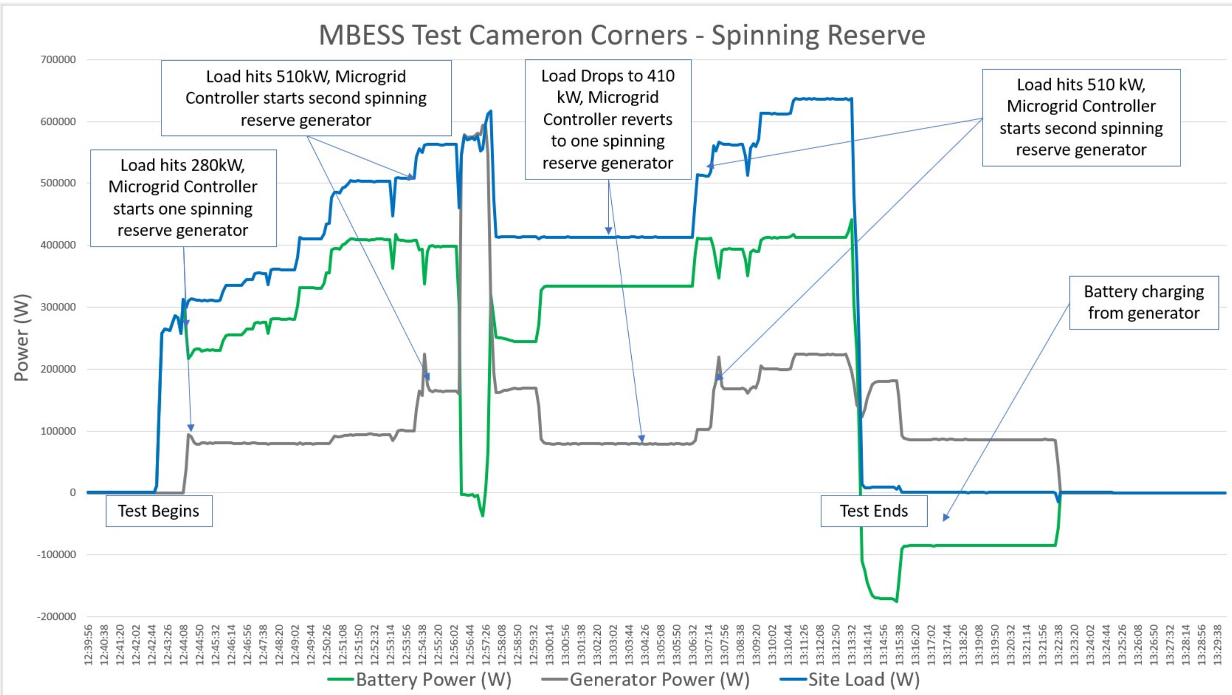

Figure 14: MBESS Test Cameron Corners - Spinning Reserve

7.2 Updated Benefits Analysis

A comprehensive benefits analysis is presented below in Table 11, based on the test results and additional analysis performed.

Table 11: MBESS Updated Benefits Analysis

Benefit Category	***Metric***	***Quantification***	***Comment/Source***
Safety	Chance of Fuel Spill vs. Diesel Generator	Decreased	MBESS contains no liquid fuel
	Noise Pollution Reduction	24	dB when compared to a diesel generator
Improved Reliability and Power Quality	Demonstrated Downstream Load Blackstart	Successful	Loads can be cold closed into an energized MBESS or ramped up slowly
	Ability to Peak Shave (Less than or equal to)	400 or 362	kW Peak shaving capacity, momentary or steady state.
	Ability to Load Smooth, minimum	126	W/s rate of change, as observed in the testing
	Increased Lifespan of Grid Equipment	2.78	Years (assumes 6% decrease in temp, correlated to circuit loading and MBESS utilization)
	Value of Lifespan Increase for Grid Equipment	$170,389	Based on average LBNA cost from SDG&E DDOR report
	Annual Grid Upgrade Deferral Benefits	$141,618	Based on SDG&E 2020 GNA/DDOR Report
Improved Performance of the Power System	Decrease in Circuit Current	30	Amps (362kW @ 12kV)
	Decrease in Circuit Current as % of Total Circuit Loading	6%	Assume Circuits are “Fully Loaded” at 500A at 12kV
Lower GHG Emissions	Annual Diesel Fuel Savings	303	Gallons of Diesel Fuel saved when using a MBESS instead of a diesel generator
	Annual Diesel Fuel Cost Savings	$1,516.30	
	Annual Diesel Fuel GHG Emissions Reduction	3	$MTCO_2e$

Benefit Category	Metric	Quantification	Comment/Source
	Annual Diesel Fuel GHG Emissions Reduction Value	\$72.14	Using August 2021 carbon pricing from California Cap and Trade market
Lower Operating Costs and More Efficient Use of Customer Money	10 Year Lifecycle Net Benefit of 362kW MBESS vs. 285kW Diesel Generator Rental	\$653,424	Includes upfront purchase cost, yearly cost to deploy and revenue generation potential
	Market Function Value (30% Participation)	\$14,660	Based on 2020 CAISO Annual Report on Market Issues and Performance
Economic Development	Create a Local Market for Purchase of MBESS to offset 2021-2030 Grid Improvements	\$11,438,320	Create a Local Market for Purchase of MBESS to offset 2021-2030 Grid Improvements
Disadvantaged Communities	Ability for SDG&E to support clean air in DACs	Increased	MBESS creates no direct CO_2 and particulate emissions unlike diesel generators and can also offset temporary load increases due to electrification such as EV charging and ship 2 shore charging.
Incremental Benefits of a Mobile Solution	Flexibility of deployment scenario	Increased	A single resource can provide backup power analogous to a diesel generator or can help defer grid upgrades or participate in the CAISO market.
	Additional revenue generation benefits over diesel generators	Grid Support, Market Functions, Grid Upgrade Deferrals	A MBESS can peak shave and load smooth, can provide voltage and frequency regulation and can be strategically deployed as needed to defer permanent grid upgrades needed from a few events.
	Increased Limit on Permissible Site Operation	Unlimited	Diesel Generators are Limited to 900 hrs/site

7.2.1 Safety

Because a MBESS uses no diesel fuel, it naturally decreases the chance of a fuel spill from a backup generation source. Actual data on fuel spills was not available from the rental agency, but any chance to decrease a diesel fuel spill is a positive thing.

One other safety benefit discovered during testing was how quiet the MBESS was vs. diesel generators, allowing for clearer communication amongst team members, improving overall site safety. Comparing average noise levels for 285kW diesel generators and a MBESS resulted in a 24dB reduction, which was enough to comfortably carry out a conversation with colleagues at normal volume levels.

7.2.2 Improved Reliability and Power Quality

Much has been said in this report about the MBESS' ability to successfully blackstart downstream circuit loads, to peak shave up to 400kW and load smooth down to 126W/s, however additional benefits for improved grid reliability were discovered during the testing.

As MBESS deployment on a grid circuit is roughly able to reduce amperage at the substation as referenced by up to 30A (362kW @ 12kV), there is an associated temperature reduction. According to grid infrastructure equipment manufacture Siemens[2], this decrease in temperature can be correlated to an increase in grid infrastructure lifespan. Assuming that the design temperature of the substation duct bank is 92^{o}C, a 6% reduction (30A reduction on a 500A "fully loaded" circuit) in temperature would lead to a 46% increase in equipment life. There is significant value associated with increased grid equipment life, and the average circuit Locational Net Benefit Analysis (LNBA) value circuit upgrade cost from SDG&E's 2020 Distribution Deferral Opportunity Report[3](DDOR) can provide a reasonable proxy to estimate value. Given values obtained from these publicly available filings, a 362kW MBESS would generate approximately $170,389 in value for increased lifespan of grid infrastructure over its 10-year life.

The MBESS itself also has value providing a dispatchable 362kW to help defer grid upgrades. According to SDG&E's addendum to their 2020 DDOR[4], SDG&E has set aside funding in a pilot program to help defer two specific grid upgrades, allowing for the calculation of value for a strategically deployed MBESS. Given pilot budgets and grid upgrade deferral needs in 2025, a 362kW MBESS would have a strategic value of approximately $141,618.

7.2.3 Improved performance of the Power System

A 362kW MBESS interconnected to a 12kV grid circuit can provide roughly 30A of current reduction. With full circuit loading approximated at 500A, before a circuit is considered full, and in need of an upgrade, this is a 6% reduction. Circuit capacity can be further reduced by interconnecting multiple MBESS on the same circuit.

7.2.4 Lower GHG emissions

Using SDG&E's 285kW generator deployment data for 2021 as a proxy for understanding GHG emissions from a "typical" diesel generator used to provide resiliency, there were small, but quantifiable benefits. First, if a MBESS were used in place of a diesel generator, there would be a diesel fuel consumption reduction, generating cost savings and GHG emissions reductions. Based on 2020 data, an average

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[2] https://new.siemens.com/us/en/products/energy/product-support/t-d-guardian-articles/electrical-equipment-lifespan-watt-in-the-world-.html
[3] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M411/K212/411212341.PDF
[4] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M402/K372/402372351.PDF

285kW diesel generator rented by SDG&E consumed 303 gallons of diesel fuel over the course of a year. At roughly $5.00/gallon of fuel, this is approximately $1,516 in fuel savings. By not burning diesel fuel, and using EPA standard emissions equivalence factors[5], that would result in a reduction of three metric tons of CO2 equivalent (MCO_2e) per generator per year. On the recent California Cap and Trade market, August 2021, those carbon credits would be worth approximately $72.14.

7.2.5 Lower Operating Costs and More Efficient Use of Customer Money

Despite a MBESS higher upfront cost than a rented diesel generator (which is effectively zero, when a third party owns, operates and maintains SDG&E's fleet of mobile diesel generators), the MBESS can generate revenue and/or create value in the ways described above in this section. Through the 10-year estimated life of a MBESS, using it for grid resiliency, circuit upgrade deferrals, to prolong the life of grid infrastructure and capturing the value of GHG emissions reductions, it is estimated to provide $653,424 in net benefits over rented diesel generators. Over a 10-year period, using a MBESS instead of a diesel generator more efficiently uses customer money to provide the same services.

As a subset of these overall costs, the MBESS can continue to provide value when not directly involved in SDG&E's day-to-day operations by participating in the wholesale power market. According to the 2020 Annual Report on Market Issues and Performance[6] published by CAISO, a battery in the San Diego/Imperial Valley Local Capacity Area can see Energy and Regulation market revenues of $134.99/kw-year. Allowing for the fact that SDG&E MBESS would target grid and resiliency support as its primary function, a conservative 30% participation in the CAISO market was assumed to yield a value of $14,660/year for a 362kW MBESS. Participation in energy market services also allows SDG&E to more efficiently provide the same services thereby using customer money in a more responsible way.

7.2.6 Economic Development

Using data found in SDG&E's 2021-2030 publicly available Grid Needs Assessment[7], it was possible to estimate how many 362kW MBESS would be needed to support grid infrastructure needs over the next 10 years. Assuming SDG&E were to choose this way to proceed, almost $11.5 million dollars would be spent procuring MBESS units, creating a local market of jobs pertaining to the delivery, setup, operation, teardown, and transportation of MBESS units. Other entities, such as commercial fleet customers and equipment rental agencies would see the MBESS in operation and conceivably explore additional units of their own.

7.2.7 Disadvantaged Communities

Unlike diesel generator, a MBESS creates no direct CO_2 emissions or particulate emissions like diesel generators, any resiliency deployments in a DAC would be in line with state and local efforts to reduce

[5] https://www.epa.gov/sites/default/files/2021-04/documents/emission-factors_apr2021.pdf
[6] http://www.caiso.com/Documents/Presentation-2020-Annual-Report-on-Market-Issues-and-Performance-Aug-12-2021.pdf
[7] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M411/K212/411212341.PDF

direct emissions in DACs. Deployment of an MBESS to specifically serve the needs of DAC customers as it pertains to air pollution reduction is in direct alignment with the original value proposition. Not only is a grid-charged MBESS a zero local emissions solution for grid support, but also the MBESS's ability to offset vehicle electrification load promotes electrification of other types of vehicles such as ships, electric vehicles and off-road vehicles, reducing localized pollution often experienced in DAC communities.

7.2.8 Incremental Benefits of a Mobile Solution

With the successful test of the MBESS as part of this EPIC funded project, SDG&E has a new, flexible tool at its disposal to provide reliable, cost-effective power to the communities served. With a single resource, resiliency services can be offered on-demand as the MBESS functions in an analogous manner to the more traditional diesel generator. When not needed in that capacity, the MBESS can be easily relocated to provide grid support and capacity to help defer grid upgrades and save SDG&E and their customers money. Finally, when no services are needed, the MBESS can be used to bid into the CAISO market and provide value to SDG&E and its customers by participating in the energy and regulation markets.

Over the 10-year life of a MBESS, significantly more revenue generation and/or value is demonstrated that the analogous diesel generator which, due to emissions restrictions, cannot provide more than emergency grid resiliency support. Also due to emissions restrictions, diesel generators are limited to roughly 900 hours/site before they must be swapped out. MBESS have no such restrictions and can remain in place as long as necessary, saving on relocation costs and allowing for them to serve medium term functions as well as short term ones.

7.3 Commercialization Cost Estimates

Cost estimates for commercialization of MBESS are presented in Table12.

Table 12: Commercialization Cost Estimates

Component		Estimated Cost	Notes
Hardware			
	MBESS	$640,000	Includes a 362kW/1499kWh MBESS mounted on a lowboy trailer, controls and monitoring software
Interconnection Equipment (for Trailer)			
	Step Up Transformer	$10,000	3-phase, 500 kVA, 12kV/480V Delta-Wye grounded
	DER Trayer Switch	$125,000	12 kV primary connections only
	Inline Disconnect	$5,000	Service level disconnect panel with NEC rated visual circuit breakers
Site Meter			

Component		Estimated Cost	Notes
	Power Quality and Revenue Meter (includes addons)	$6,400	Site specific meter required to measure respective site loads to get a true load reading at the PCC
	Current Transformers	$400	3-phase CTs to step down current to a safe level for site meter
	Potential Transformers	$400	Site specific 3-phase PTs to step down voltage to a safe level for site meter
Total Upfront Costs		**$787,200**	
Ongoing Costs (Per Deployment)			
	Site Preparation	$2,500	Existing infrastructure upgrades (e.g., transformers, switches, etc.)
	Permitting	$2,000	Estimated based on Port of SD discussions
	Labor	$2,240	Estimated 8 hrs Electrician @ $150/hr + 8 hrs Tech @ $130/hr
	Transportation Costs	$1,500	Per site. Includes delivery and removal
Total Per Site Costs		**$8,240**	

8.0 Findings

The project demonstrated the flexibility of an MBESS and value of a relocatable battery resource to SDG&E's power system operations and customer services, which is not possible from either existing diesel generators or a permanent stationary battery resource. The MBESS effectively performed all functions demonstrated in either a grid support or grid forming capacity. A refined value proposition for commercial use of MBESS's was developed.

8.1 Findings Discussion

Findings from this MBESS demonstration project show the flexibility of such a resource and the variety of stacked benefits that can be attributed to a single asset. Table 13 provides a list of utility applications for a MBESS resource.

Table 13: Potential MBESS Applications

Interconnection	Application	Notes
Grid Parallel, FtM	Grid Support Services – Peak Shaving, Load Smoothing, Demand Response,	Utility places a MBESS in a strategic location to provide grid

Interconnection	Application	Notes
	Infrastructure Deferral, UPS for critical load support	support to alleviate temporary capacity issues or defer grid upgrades.
Island, FtM	Utility infrastructure construction, PSPS/outage support, microgrid testing/commissioning	Instead of rolling a diesel generator, use a MBESS in its place.

An MBESS connected in parallel with the grid, in front of the meter, demonstrated significant benefit to provide grid support services, such as peak shaving, load smoothing, and demand response, reducing wear on grid infrastructure, prolonging equipment life and deferring grid upgrades. The mobile nature of this resource allows the battery to be deployed to support intermittent and temporary load increases when needed and deployed elsewhere when not. Intermittent loads which would be optimally served by a MBESS would include cruise ship docking, sporting events, entertainment events or other discrete or seasonal events which set new circuit loading peaks to serve specific events.

The MBESS in this project also successfully provided resiliency to the grid, much like a mobile (diesel) generator would, powering downstream loads when the grid was not available. It was able to blackstart certain loads up to (and slightly beyond) the rated capacity of the battery and coordinate grid-forming operations when connected in parallel to traditional generation sources. The microgrid controller's ability to control grid-forming operations demonstrates its ability to coordinate various different generation sources, including renewables, ultimately leading towards a fully resilient and carbon-free microgrid.

When not in use for these functions, the MBESS can be relocated to a strategic location to perform energy and regulation market functions on the CAISO market, generating revenue for the MBESS owner. Further study will ultimately be needed to understand the permissibility of this function for different owners, including SDG&E.

8.2 Updated Value Proposition

With the test results and successful demonstration of use cases above, SDG&E was able to create an estimated value proposition comparing the net benefit of a MBESS vs. a traditional diesel generator over the 10-year useful life of a MBESS. Currently, SDG&E acquires diesel generators to provide grid resiliency through a rental model, significantly simplifying the procurement, maintenance and management of these devices. While this may ultimately prove a viable model for MBESS use, it is not available today, so 10-year costs of a 362kW purchased MBESS were compared to rental costs of a 285kW diesel generator, a roughly equivalent piece of equipment. MBESS costs were attributed based on commercialization costs estimated above in Table 12 of this report. Rental costs for 285kW diesel generators were based on 2021 rental cost data from SDG&E's DER group. As seen in Table 14 below which shows the upfront, yearly and revenue potential costs for a 362kW MBESS and a 285kW diesel generator, the purchased MBESS has much higher upfront costs than the rented diesel generator, but also is able to generate significant revenue and value for SDG&E, whereas the diesel generator is solely a sunk cost.

Table 14: Cost Comparison of 362kW MBESS Purchase vs. 285kW Diesel Generator Rental

362kW MBESS (Purchase Model)		**285kW Diesel Generator (Rental Model)**	
Item Description	**Cost**	**Item Description**	**Cost**
Mobile Battery Energy Storage System (MBESS)	$640,000	Diesel Generator	$0
MBESS Accessories	$147,200	Diesel Generator Accessories	$0
Total Upfront	**$787,200**	**Total Upfront**	**$0**
Site Preparation Costs	$9,583	Site Preparation Costs	$9,583
Mobilization Cost	$22,003	Rental Installation Cost (Per Generator Per Year)	$7,078
Charging Cost	$2,043	Fueling Cost (Per Generator Per Year)	$1,516
Maintenance Cost (including repair and service)	$500	Maintenance Cost to SDG&E (Rental)	$0
Total Yearly Costs Per MBESS	**$34,129**	**Total Yearly Costs Per Generator**	**$18,178**
Circuit Upgrade Deferral Revenue (DDOR)	$141,618		
GHG Emissions Reduction Value	$72		
Market Function Value	$14,660		
Equipment Upgrade Deferral Value	$17,039		
Total Yearly Revenue Generation Potential	**$173,388**	**Total Yearly Revenue Generation Potential**	**$0**

Over the 10-year life of the MBESS, the cumulative net benefit cashflow can be seen in Figure 15, comparing a purchased 362kW MBESS and a rented 285kW diesel generator.

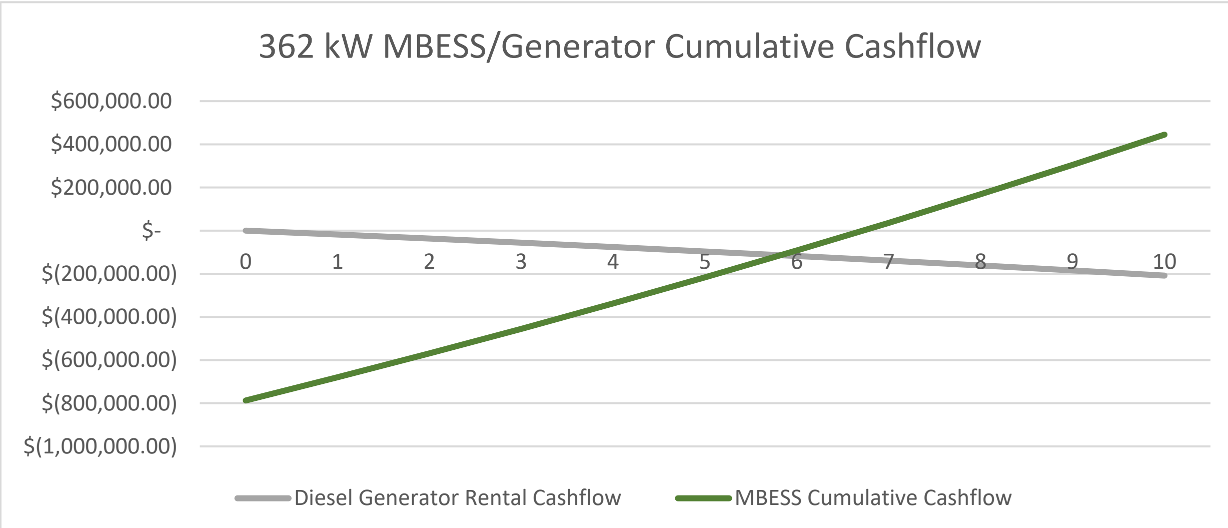

Figure 15: 362 kW MBESS / Generator Cumulative Cashflow

In 10 years, a MBESS, deployed through multiple resiliency, grid services, grid upgrade deferral and market functions has the potential to generate over $650,000 of net benefit over continuing to rent diesel generators.

A MBESS deployment is also aligned with state initiatives which seek to curb GHG emissions while supporting the loading order, promoting zero emission vehicles and stimulating economic development. Beyond the state initiatives outlined earlier in this report, a MBESS can offset the load increases due to vehicle electrification as stated in CARB's EO N-79-20 mandate, which seeks to have 100% of new passenger vehicles in the state electrified by 2035, 100% of medium and heavy-duty vehicles electrified by 2045, 100% of drayage trucks electrified by 2035 and 100% of off-road equipment electrified by 2035. A MBESS and connected charging stations can be moved to support strategic vehicle charging wherever a new concentration of vehicles appears.

MBESS testing in the EPIC-funded pre-commercial demonstration revealed several additional use cases and values for further exploration which would serve to only increase the value of a MBESS beyond what was estimated above. These include:

- Frequency Regulation - A MBESS which is powering downstream loads can potentially improve frequency regulation by more closely matching power generation with downstream loads. Data observed from the Mobile Battery in grid forming mode showed that downstream load frequency was maintained between 59.93 and 60.04 Hz during islanded operation. A MBESS could also support larger grid frequency regulation by temporarily islanding key sections of the grid with voltage sag until a more permanent solution can be found. Frequency regulation is also a key component to unlocking value in the wholesale energy market.

- Volt/VAR Regulation - Introduction of a MBESS into an in FtM grid-paralleled application can help correct site power factor and align real and apparent power delivered.
- Scheduled Charging and Discharging - Software associated with the MBESS can look at grid carbon content, predicted load, solar PV production and determine optimal times to charge and discharge the battery to maximize greenhouse gas reductions from the MBESS and other distributed energy resource deployments. Scheduled charging can also be used to avoid charging the battery from the grid during circuit peak loading times.
- Uninterruptable Power Supply – Much like critical facilities have backup generation on-site with automatic transfer switches ensuring seamless power during an outage, the MBESS equipped with the proper software and site controls can handle the automated switching of grid-fed loads to backup-fed loads.

9.0 Conclusions

The MBESS successfully performed all the desired functions that were demonstrated, including FtM grid support functions and blackstart/islanding functions, as described in detail above. Once configured and interconnected, the battery performed according to expectations, or exceeded expectations, in every test. There is every expectation that the battery would continue to perform at expectations in future similar applications, as long as the loads that it serves are within the operating capacity of the battery.

A challenge experienced with the MBESS deployment was that varying setups were required for different battery applications and different grid conditions at each point of interconnection. This included voltage conditions, interconnection methods, metering options and required hardware. Because this was a pre-commercial demonstration project, each battery application was custom tailored to the task at hand with extra metering required to verify battery operation outside of the onboard site controller and management software. Beyond the extra testing equipment required, configuration and control of various MBESS parameters through DNP3 protocol required considerable effort to program the battery to perform the intended functions properly.

The MBESS tested in this EPIC project has a high potential value proposition when all potential uses of the battery are considered including resiliency services, circuit upgrade deferrals, GHG emissions reductions, market function participation and equipment upgrade deferral value.

Sized appropriately and deployed in a coordinated fashion, the MBESS provides analogous functionality to a mobile diesel generator which can black start loads after an outage, coordinate with other supporting generation sources and carry loads until grid power can be restored. However, the key to unlocking the value of a MBESS is in its use when not acting as a mobile generation source.

Based on 2021 SDG&E generator deployment data, the average 285kW generator was deployed for just over 30 hours, providing critical backup generation for the grid, but leaving ample time throughout the year to support other grid and customer needs. Taking these other functions into account, the MBESS shows the most value to SDG&E by supporting circuit upgrade deferrals, which are targeted and timebound grid needs, perfectly aligned with the flexibility of a (fleet of) MBESS. In summary, a single 362kW MBESS is able to generate over $650,000 in additional benefit. While the upfront cost is high, the reward for coordinated and strategic deployment can be great and should be explored further as SDG&E expands its interest in MBESS technology.

Beyond its economic value, the MBESS would also deliver significant societal benefits. It addresses the State's and SDG&E's GHG reduction and DAC goals, it furthers carbon reduction agendas, electrification efforts, and it generates significant economic potential surrounding the procurement, sales, service and deployment of a fleet of MBESS, all in an emissions free and quiet way. Customers, such as MGBW, seeing public use of battery storage, become curious themselves and want to investigate the role batteries may play in helping them to reduce their own operational costs.

A MBESS can be specifically deployed in DAC communities to reduce or eliminate increases in GHG emissions from ships, trucks or other vehicles which would more traditionally idle their internal combustion engines while stationary.

By scheduling charging of an MBESS during clean energy resource availability when the utility power system is powered by a significant amount of renewable resources, an MBESS can store excess clean energy and deploy it during times when the power system relies more on fossil fuel for power generation.

10.0 Tech Transfer Plan

10.1 Project Results Dissemination

The results of this module of EPIC-3, Project 7 will be published and made available to the general public in this comprehensive final project report, which will be posted on SDG&E's public website and filed with CPUC. This report is the main record of what was demonstrated and learned in the project and is the primary tech transfer tool. The project's results and findings will also be submitted for consideration by organizers of public and industry conferences.

10.2 Transition for Commercial Use

A few key next steps surfaced as part of the learnings from this MBESS pre-commercial demonstration which will assist the transition of such a technology transfer to commercial use.

All relevant components needed to support a MBESS should configured and placed on the same trailer, including relevant disconnects, back feed protection, site meters, and transformers. A single trailer can then be rolled into place and more efficiently connected to a variety of different interconnection voltages and configurations. Once the trailer configuration is complete, a standard list of interconnection types should be developed to determine MBESS deployment applicability with the trailer.

With an all-in-one trailer configuration, this MBESS should also be tested in a behind the meter application for any customer who experiences temporary load increases such as a local university which has to deal with the increased electrical loads associated with a concert or graduation. Key learnings from this process should then inform the product deployment agreement, liability sharing and fee structure of a potential future deployment.

An MBESS should also be further tested to charge from on-site solar PV to further reduce the GHG impacts of its deployment and to test the cyclical charge/discharge associated with a solar PV fed battery.

Before commercialization, it is recommended that SDG&E look at their current interconnection regulations to more easily accommodate a mobile battery deployment in the future. Permissible use cases need to be further defined, as do the MBESS parameters to allow for expedited unit deployment a host site.

It is also recommended for SDG&E to establish procedures for treating an MBESS as a capital asset, much like they do transformers or other infrastructure equipment, defining product lifecycles, capitalization, and other key parameters before funding a fleet of MBESS units out of their general rate case. Internal SDG&E processes need to be built pertaining especially to standards and operating parameters to standardize procurement and deployment of these assets.

Finally, SDG&E should consider where a fleet of MBESS's is stationed when not deployed to maximize revenue or utility benefit. A fleet of undeployed and strategically located MBESS's could be charged from excess solar PV during the day to return 100% renewable power to the grid after sunset and the same fleet could also have the capacity to perform market functions, buying and selling power as the power market fluctuates.

11.0 Recommendations

Use of a MBESS in the following use cases will yield significant benefits to SDG&E as discussed in Section 8 above. Table 15 outlines the use cases and reasons for deploying a fleet of MBESS.

Table 15: MBESS Use Case Recommendations

Use Case	Recommended?	Why?
Safety	Yes	MBESS projects contribute to overall site safety with adequate E-stop capabilities, lack of tailpipe emissions, noise and auto-phasing capabilities when closing into downstream loads.
Load Factor Correction	Yes	A MBESS can shave high peak loads and improve a customer's load factor. More predictable and level power consumption benefits the the utility infrastructure.

Use Case	Recommended?	Why?
Load Smoothing	Yes	Smoother load changes benefits the lifespan of the utility infrastructure.
Demand Peak Shaving	Yes	A MBESS can eliminate peaky demands benefiting the lifespan and necessity to upgrade utility infrastructure.
Demand Response	Yes	MBESS can be dispatched to provide circuit capacity on demand.
Deferral of utility infrastructure investments	Yes	MBESS technology can be strategically deployed to alleviate the costly need for circuit upgrades due to infrequent circuit capacity issues. Or they can be temporarily deployed to provide capacity while circuit upgrades are planned and constructed.
Load Blackstart	Yes	A MBESS can successfully black start downstream customer loads. It can also act as the primary grid-forming microgrid controller operating in conjunction with other generation sources. When a MBESS is used in conjunction with diesel generators, it can significantly reduce the runtime of those generators.

It is recommended that SDG&E pursue commercial adoption of MBESS. It is recommended that SDG&E continue to refine and standardize system hardware, demonstrate other deployment scenarios, and adapt existing utility processes to allow for mobile energy sources. In the immediate future, additional sites and use cases should be demonstrated with the residual funds in the EPIC project to enhance the base of experience and better understand which applications have the greatest commercial value proposition. It is recommended that SDG&E's DER group lead the commercial adoption process. This group already manages SDG&E's mobile generator program. SDG&E's DER group should also coordinate with those internal resources responsible for grid planning to further discuss the potential for a fleet of MBESS to alleviate or eliminate the future needs for circuit upgrades. Given the fledgling nature of a MBESS supply industry, commercial adoption should consider both purchase and rental options for MBESS in the long term, similar to what is now done with mobile generators.

EPIC Final Report

Program	Electric Program Investment Charge (EPIC)
Administrator	San Diego Gas & Electric Company
Project Number	EPIC-3, Project 7, Module 2
Project Name	Demonstration of a Multi-Purpose Mobile Battery at Community Resource Centers
Date	December 31, 2021

Attribution

This comprehensive final report documents the Electric Program Investment Charge (EPIC) 3, Project 7, Module 2. The project team that contributed to the project definition, execution, and reporting included the following individuals, listed alphabetically by name:

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Executive Summary

Objectives

The objective of SDG&E's EPIC-3 Project 7 was to perform a pre-commercial demonstration of mobile battery energy storage systems (MBESS) and examine the value proposition from using MBESS across multiple sites and use cases.

Due to the current high cost of leasing or owning and operating energy storage systems, stacking multiple MBESS applications and incorporating added benefits of frequent relocation and quick installation/energization (plug-and-play) to support day-to-day business needs are key demonstration features included in this EPIC project. The remote nature of certain customers located in high fire risk areas of the SDG&E service territory, facing forced outage events for long periods (up to 72 hours) a few times during the fire season, requires a robust, reliable, and easily relocatable power supply solution.

Approach

The project was split into two work modules. This report covers Module 2, which focused on demonstrations at community resource centers. Module 1 focused on other applications and is covered in a separate report. Module 2 covered a series of tasks, including:

- Selection and evaluation of baseline value propositions for an initial set of use cases, such as outage management for customers in a wildfire zone and a wide range of grid supporting or day-to-day maintenance operations.
- Delivery of a pre-commercial MBESS solution that meets the functional specifications after completing the factory and site acceptance tests and initial interconnection verification.
- Supporting the logistical aspects of the project demonstrations at two selected sites (community resource centers) in remote areas of the service territory.
- Demonstration of MBESS uses cases at the sites.
- Collection and analyzing the demonstration results to determine the benefits and value proposition of MBESS in the context of pre-defined benefit categories and available customer sites in remote and vulnerable areas of the service territory.
- Engineering analysis and preparation of the comprehensive final project report, including recommendations regarding commmericial adoption.

Key Accomplishments

The demonstration at the two sites clearly showed the viability and value of utilizing MBESS for supplying the customer loads during a specific period when supply interruption (outage) is expected. The approach alleviates the need for maintaining a stationary backup generation source at a facility year-round. It also showcases an alternative to conventional diesel generators, which are highly prone to noise pollution and greenhouse gas (GHG) emissions.

There is concern with safely transporting fully charged battery cells, when using MBESS. The project showed that mobility could be achieved with proper use of the technology and adequate design to incorporate sensors and monitoring and the technical capability for enabling the solutions.

Key accomplishments in this project include:

- Relocating the MBESS from one place to another could be performed relatively easily, using typical tractor trucks from the utility equipment operations fleet.
- Connection of the MBESS to the customer-generator terminal box at each site was performed swiftly with minimal power interruption to the facilities. It required the connections to be made by a qualified electrician, properly trained to work on medium to low voltage equipment, with their specialized skill and tools.
- Using manual mode and following a few steps, the MBESS was easily started by pressing the "start pushbutton" on the terminal box. The system status and operation could be checked frequently using a user screen on a portable tablet that provides remote access to the unit Human-Machine Interface (HMI).
- External to the MBESS container, the noise emitted during the unit operation was minimal, which is a major advantage of using the MBESS, especially in locations with residential customers. With diesel generators, the noise pollution can exceed 60 dB.
- The unit operation and backup generation supply to a CRC was successfully demonstrated at both sites, for more than 16-hours, with no need to stop or start the unit. With diesel generators, the unit may need to be stopped after 6-8 hours and restarted to meet the hard duration limitation for emergency use of diesel genset (enforced by local jurisdictions in some areas).

Recommendations

- The key recommendation from this project is for SDG&E to adopt MBESS into their commercial operations. The value proposition shown in this Module 2 of EPIC-3 Project 7 and the companion work of Module 1 indicates significant benefits can be derived from the use of MBESS.
- It is recommended that SDG&E’s DER group take the lead to commercially adopt MBESS in the SDG&E territory and engage other business units in developing a commercialization plan.
- The use cases demonstrated in the project were limited to the outage management scenarios due to the configuration at the CRC sites. It is recommended to perform additional testing and evaluation at other potential sites to analyze the value proposition in other use cases.
- It is recommended that future projects incorporate both single-phase and three-phase outputs for MBESS to support residential and commercial facilities. The multiple output type will increase the coverage and utilization cases for the system.
- Integration to the dispatch center and remote control or observability were not part of the EPIC project. However, remote dispatch and monitoring will need to be key aspects of the field operation.
- Depending on the number of relocations expected, a combined truck-trailer approach may become more beneficial and convenient than a flatbed trailer in support of multiple use cases and utility applications.
- An MBESS can be equipped with electric vehicle chargers for the additional benefit of supporting customers during outage scenarios. A hybrid MBESS with an onboard charger will significantly improve the business case and come at a low incremental cost.

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List of Acronyms

Acronym	Acronym Description
ATS	Automatic Transfer Switch
BCR	Benefit to Cost Ratio
BESS	Battery Energy Storage System
BMS	Battery Management System
BTM	Behind the Meter
C&I	commercial and industrial
CPUC	California Public Utilities Commission
CRC	Community Resource Centers
DAC	Disadvantaged Community
DER	Distributed Energy Resource
DNP	Distributed Network Protocol
EOL	End of Life
EPIC	Electric Program Investment Charge
E-Stop	Emergency Stop
FAT	Factory Acceptance Testing
GCM	Grid-Connected Mode
GHG	Greenhouse Gas
HMI	Human Machine Interface
IRR	Investment Rate of Return
ITF	Integrated Testing Facility
LFP	Lithium Ferrophosphate
LiFePO4	Lithium Iron Phosphate
MBESS	Mobile Battery Energy Storage System
$MTCO_2e$	Metric Tons of Carbon Dioxide Emissions
MTS	Manual Transfer Switch
NFPA	National Fire Protection Association
O&M	Operation and Maintenance

Acronym	Acronym Description
PCC	Point of Common Coupling
PCS	Power Conversion System
POI	Point of Interconnection
PSPS	Public Safety Power Shutoffs
RFP	Request for Proposal
ROI	Return on Investment
SAT	Site Acceptance Testing
SCADA	Supervisory Control and Data Acquisition
SDG&E	San Diego Gas & Electric
SLD	Single Line Diagram
SOC	State of Charge
UPS	Uninterruptible Power Supply
USD	U.S. Dollar
VPN	Virtual Private Network

1.0 Introduction

The objective of SDG&E's EPIC-3 Project 7 was to perform a pre-commercial demonstration of mobile battery energy storage systems (MBESS) and examine the value proposition from using MBESS across multiple sites and use cases. An MBESS is a battery energy storage system on wheels that can provide multiple use cases based on a single MBESS application or a combination of several applications (stacking of applications) to provide grid support and reliability/resiliency solutions for utility projects at different sites.

This EPIC project was initiated by assessing the potential use cases and benefits of using a mobile battery system when rotated between multiple locations as part of the utility fleets. Customer and utility benefits were investigated from different viewpoints, including reliability and power quality, power system performance, greenhouse gas emission level, cost of operation, and infrastructure investment efficiency.

Based on the outcome of initial investigations and analyses, a baseline methodology was proposed to quantify benefits for mobile energy storage solutions by including the incremental benefits of mobility compared with stationary battery energy storage system (BESS) applications. Various state environmental and energy regulations were considered in the proposed approach.

1.1 Project Objectives

The key project objective was to execute a pre-commercial demonstration of mobile energy storage systems and evaluate the value preposition for utilizing the MBESS in different applications. The project was split into two modules with different mobile MBESS units, sites, and use cases in each module. This report covers Module 2, in which an MBESS was employed at two community resource centers (CRCs) in SDG&E's service territory during planned outages. Module 1 is covered in a separate report, available on the SDG&E public website.

In Module 2, the MBESS demonstration was accomplished at Dulzura and Pine Valley Community Resource Centers. These sites have been equipped with a 120/240 V single-phase generator connection box at the interconnection point (POI). In addition, demonstration data were collected and analyzed at both sites to investigate the mobile battery system performance from safety, reliability, control, and monitoring viewpoints.

The tests carried out in the demonstration show that mobile batteries can be a proper alternative and have potential value for emergency backup power supply sources at CRCs. Likewise, the associated logistical and operational constraints were identified.

A focus of this project was the assessment of a mobile battery's effectiveness for emergency backup power and tradeoffs as an alternative to diesel generators. The goal of the assessment was to determine the value proposition for using mobile batteries in alternative use cases and develop recommendations to SDG&E regarding commercial adoption.

2.0 Issues and Policies Addressed

A mobile storage unit can be used to address various issues and policies, including but not limited to:

Disadvantaged Community (DAC) Policy

The Clean Energy and Pollution Reduction Act of 2015 (known as Senate Bill 350 or SB 350) calls upon the CPUC to help air quality and economic conditions improve in communities identified as "disadvantaged."

Disadvantaged communities refer to the areas throughout California that mostly suffer from a combination of economic, health, and environmental issues such as poverty, high rate of unemployment, air and water pollution, presence of hazardous wastes, and high incidence of asthma and heart disease. State policy directs that EPIC funding prioritizes projects that benefit these disadvantaged communities.

Fire Safety and Public Safety Power Shutoffs (PSPS)

SDG&E is committed to operating its electrical system safely and is authorized to de-energize circuits as a last resort, when needed (such as fire safety events), to protect public safety. SDG&E stands up various community resource centers to assist the public and support customers affected by providing essential food, water, device charging, and outage updates. Currently, these CRCs are powered up through backup diesel generation and could attain benefits from a mobile battery solution.

3.0 Project Focus

The focus of this project was to demonstrate a pre-commercial MBESS capable of supporting the load at the CRCs for up to 72 hours, which is a typical duration for a public safety power shutoff (PSPS); however, power can remain shut off as long as the threat to the SDG&E system and public safety continues. CRCs are single-phase loads with peak loads ranging from 7-35 kW.

A single-phase, 150 kVA version of MBESS was selected for this demonstration. This MBESS was deployed at two CRCs to demonstrate the use cases and policies that can be addressed using this technology and clarify the value proposition for the selected use cases.

To support more inclusive investigation and verification, all essential data during system operation and demonstration were captured by the MBESS internal datalogger.

3.1 Description of MBESS

The selected MBESS for this demonstration, referred to as the MBESS, is designed for frequent relocation and fast interconnection at a new site, using a standard generator terminal box with Cam-Lok plugs.

The MBESS is a clean alternative for emergency diesel generators. Additionally, using a fully portable platform enhances the value proposition. It increases the utilization factor of the energy storage system by introducing flexibility in capturing the locational benefits of grid support or customer-specific applications.

The MBESS unit selected for the EPIC project is a single-phase system. It includes an onboard 150 kVA isolation transformer to provide a customer-specific connection for 120/240 V split-phase (3 wire). Figure 3-1 illustrates a simplified schematic of the MBESS for this project.

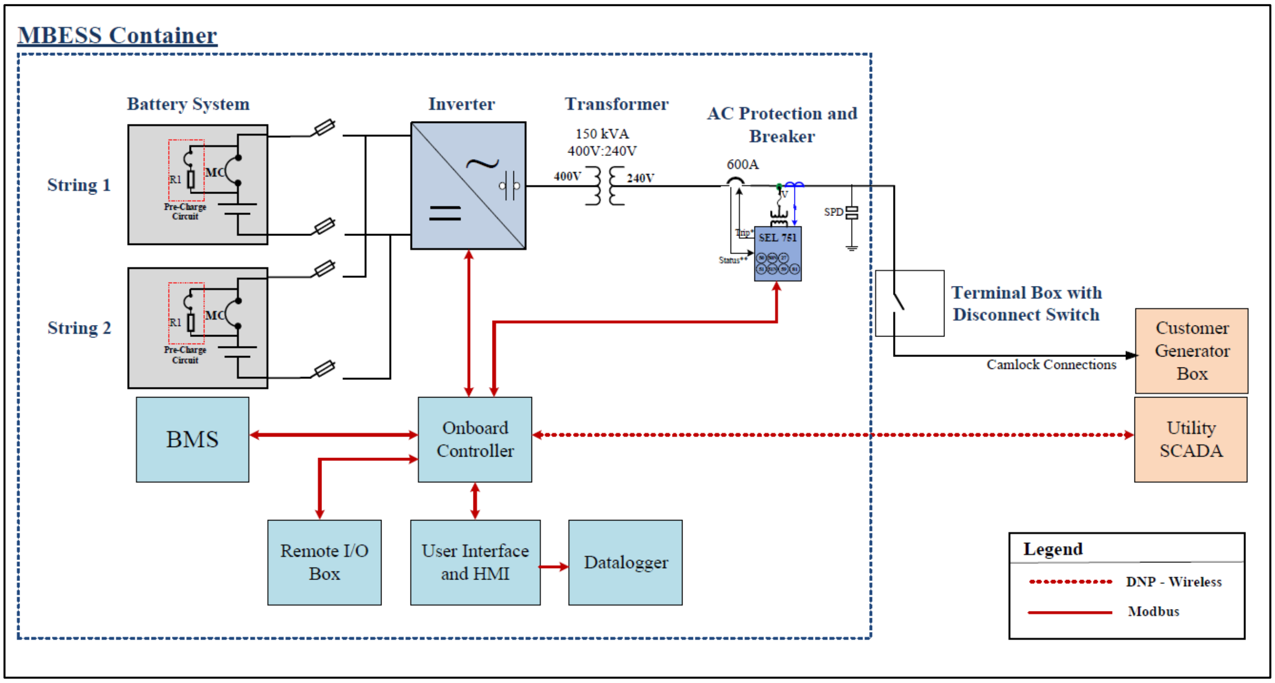

Figure 3-1. Simplified Schematic of MBESS. BMS is the battery management system.

Figure 3-2 presents a picture of the actual MBESS trailer used for this demonstraton.

Figure 3-2. MBESS Container used in the project

3.2 Controls and Applications

The MBESS selected for this demonstration is equipped with a microgrid integrated automation system using an onboard controller that provides a comprehensive set of autonomous controls, optimization schemes, and supervisory capacity for ease of local operation or remote operator access through integration into a utility dispatch center overall grid coordination. Figure 3-3 presents a picture of the home page of the Human Machine Interface (HMI) of the MBESS. Through the HMI, the user can monitor the measurements and control the system operations. Most day-to-day operational measurements can be found on the homepage. The HMI actions that can be taken include starting and stopping the system, adjusting the system setpoints, and changing operation modes.

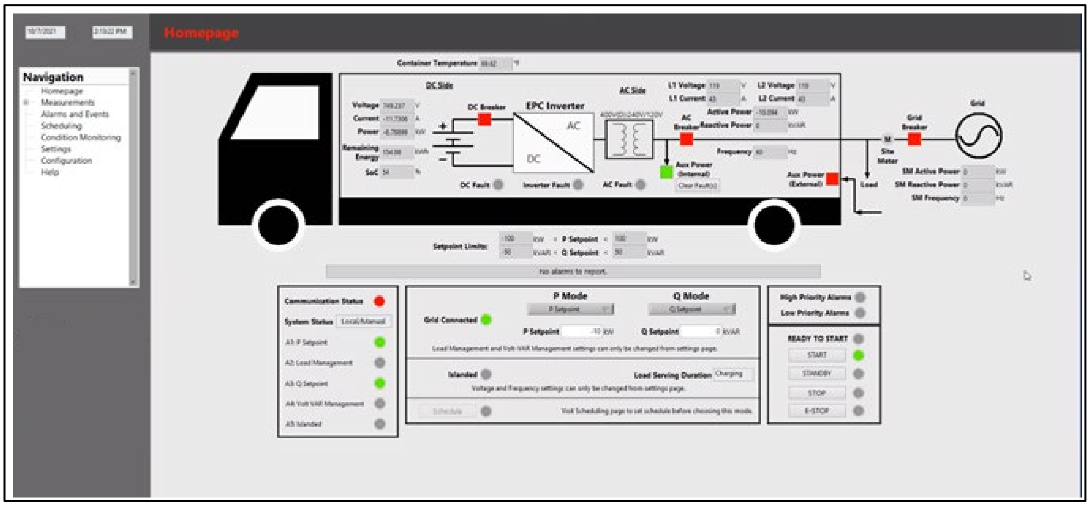

Figure 3-3. MBESS HMI Homepage

It should be noted that for traceability and safety purposes, all inputs provided by the user are logged and recorded in a local data logger; this includes sending commands, pressing buttons, changing setpoints, and switching HMI pages.

The MBESS provides two modes of operation: Grid-connected and Islanded operation.

The user can control how the system handles its P and Q outputs separately in the grid-connected mode. The Load Management mode for active power keeps the power flow within a pre-defined range by the user, and the Volt-VAR mode follows a droop curve provided in the Settings page while providing voltage and reactive power support to the grid. Additionally, the pre-commercial MBESS used in this project is also capable of Islanded operation supplying customer loads off-the-grid and isolated.

MBSS has two control modes: Local and Remote. The local control has Manual and HMI (automatic) mode, and both are performed at the site. A tablet is used for accessing the HMI by the user at the site. For manual control, a selector switch and start/stop pushbuttons are incorporated on the front panel of the terminal box. In remote control, the user or operator can access the HMI screen through a virtual private network (VPN), or the commands can be sent to the MBESS from a Distributed network protocol (DNP) communication route implemented for the remote interface, such as supervisory control and data acquisition (SCADA) access for a dispatch operator.

Both grid-connected and islanded modes rely on communications with certain hardware inside the MBESS container, managed through its internal controller. If communications with devices fail, the system will stop operating and refuse any restart attempt. Pressing the red/green circle next to the "Communication Status" label on the homepage will open a page showing the status of all relevant communication channels in the network, which can be used to find out if a device has stopped operating.

The user can navigate the Settings or Configuration pages to change more specialized operational parameters. Detailed measurements can be found on the Measurements page, where the measurements and graphs are divided based on their sources and types.

Certain alarms are defined by the system, which are grouped based on their severities from high to low. It should be noted that all alarms must be acknowledged by the user and remain in the device's history for future traceability.

4.0 Project Scope Summary

The scope of work for the EPIC project included delivering a fully functioning portable MBESS for single-phase supply of customer load and performing Site Acceptance Testing (SAT) at SDG&E's Integrated Testing Facility (ITF) before deploying to the field for two site demonstrations. The scope also covered associated services and support to facilitate pre-commercial demonstrations at two different CRCs, collecting demonstration tests data, engineering analysis, and reporting.

4.1 High-level overview

The project scope includes the following major tasks:

Task 1: MBESS Delivery

This task covered delivering a pre-commercial portable energy storage system to test and demonstrate a series of use cases for grid support and outage management during forced or maintenance power shutdown affecting customers in remote areas of SDG&E service territory. This task also included the factory acceptance testing (FAT) at Quanta Technology's Sustainability Testing Integration Laboratory before transporting the MBESS to the SDG&E site and transporting the MBESS to the SDG&E ITF at Escondido.

Multiple stakeholders' meetings and workshops were held with the SDG&E team during the execution of this task to finalize the design of MBESS and perform baseline analysis of the benefit areas identified for this EPIC project.

Task 2: Installation Services

During this task, the SDG&E/Quanta Technology team prepared the site installation and interconnection of MBESS at ITF and both CRC sites for demonstration stages.

As part of this work, a set of interconnection single-line diagrams (SLDs) and installation drawings were developed to facilitate the installation at each site.

It should be noted that the MBESS is designed to have a plug-and-play concept by using cables with Cam-Lok connectors to streamline the connection and disconnection of MBESS to existing generator boxes at different sites. In addition, MBESS is equipped with inter-tie protection, circuit breakers, and a visible manual disconnect switch, required by the SDG&E interconnection standard at POI for connecting MBESS as a distributed energy resource (DER) to distribution systems.

Task 3: Site Acceptance Testing (procedure and testing)

Upon delivering the device to ITF, the team tested various device operation modes. It verified the operation of MBESS before relocating the MBESS to customer sites for the use case demonstration.

Task 4: Relocation Services

As part of this task, the project team supported the de-energization and relocation of MBESS between different sites.

Task 5: Demonstration Support

Quanta Technology and SDG&E performed use case demonstrations at two different CRC sites. This task included the demonstration efforts and the data collection at each site.

Task 6: Data Analysis Support

Upon completing the demonstrations, the team focused on organizing and analyzing the data collected from each site. This task included the following efforts:

- Assimilation of test results
- Analysis of demonstration results

Task 7: Engineering Support

In this task, the team performed a set of studies based on demonstration results to assess the value proposition of key applications for prospective commercial adoption of MBESS.

Task 8: Reporting and Documentation

This task covered all logistics related to the reporting aspects of the project, including a comprehensive final report, meetings, monthly technical and progress reports, and project management.

5.0 Project Approach

Various benefits are associated with utilizing MBESS across the utility service territory. However, the applications may vary depending on the characteristics of sites where the device is deployed and the use case(s) specific to a customer. Hence, the initial task in the project execution plan covered the investigation and identification of the potential key use cases and customer sites that can demonstrate various value streams associated with the MBESS.

In addition, appropriate performance metrics were defined to evaluate the success/ failure of each use case and the overall benefits from deploying MBESS.

Once the use cases, sites, and performance evaluation metrics were determined, the team performed a detailed baseline analysis to be further evaluated and adjusted based on results from site demonstrations. Comparing the data gathered from a real-world demonstration of the use case with baseline analysis result, the team was able to quantify the benefits and prove the value-added of MBESS.

This section of the report presents a list of selected use cases for the MBESS, followed by a list of selected metrics for the device operation and results from the baseline studies of the benefits associated with MBESS in the context of each use case. Additionally, this section of the report also provides information regarding the pre-commercial demonstration at two selected CRCs and the process for data acquisition and analysis from the field.

5.1 Use Cases

Table 5-1 presents a brief overview of the target use cases for a single-phase MBESS considered in this project. Additionally, this table provides a list of initial assumptions associated with each use case for performing baseline analysis of different benefits associated with the MBESS technology.

Table 5-1 Single-Phase MBESS Use Cases with Their Descriptions

#	Use Case	Description
1	Planned outage management for PSPS support	Public Safety Power Shutoff program
2	Unplanned outage management	An unexpected loss of the utility source
3	Maintenance outage management	System upgrades related outages, scheduled in advance, such as service transformer upgrade, cable replacement, pole replacements

Regarding energy capacity, a typical PSPS duration lasts 72 hours, and the customers are alerted as far in advance as 10 days and as short as 48 hours before a scheduled event. In the worst-case scenario, they will be announced at least 1 hour in advance. This time duration is enough for the MBESS to be transported and connected to supply the critical customer loads as a clean alternative for mobile diesel generators.

Additionally, the mobility aspect of the MBESS provides a unique opportunity for the utility for stacking of use cases based on the time of year and at different locations within the service territory. Below is a sample of a seasonal stacking of use cases for the MBESS:

- **Fall/winter months:** Planned outage management for PSPS events. It should be noted that most PSPS outages happen during these months.
- **Summer:** Load and unplanned outage management.
- **Spring:** Maintenance outage management.

5.2 Baseline Studies/Fact-Finding

Benefits associated with the MBESS can be categorized into six groups (presented in **Figure 5-1**.

Figure 5-1. Initial Benefit Areas of MBESS

The above benefits can also be associated with a stationary battery energy storage system. However, utilizing a mobile battery solution provides the capability to the operator to deploy the system at various sites throughout the year to maximize the benefits.

5.2.1 Benefit Areas Associated with MBESS

Safety

The solution utilized for the project complies with required safety codes for energy storage systems and using mobile solutions on the road. Some criteria which were well-thought-out in the demo assessment are ease of transportation using heavy-duty trucks and vehicles commonly used by utility fleets, fire safety, utility interconnection, electrical safety, and some local permitting requirements. Below is a list of key safety and fire prevention features associated with MBESS design:

- Visual and audible fire alarms
- Physical emergency stop (E-stop) that de-energizes the entire system
- Full separation of DC system (battery cells and components) and AC system (inverter and switchgear)
- Ungrounded DC and AC with the use of an isolation transformer
- Equipped with a state-of-the-art battery management system (BMS), with UL1973 certification.
- One of the safest battery chemistries in the industry is based on lithium iron phosphate ($LiFePO_4$), or LFP for short.
- Total kWh energy per battery enclosure is well below 50 kWh recommended by NFPA 855
- STAT-X spot smoke detector and arc-triggered fire-suppression system
- Capable of condition monitoring and preventative (predictive) asset evaluation with use of real-time measurement at the component level (cells and inverter) and data analytics

One vital point is that the designated safety approaches in this project require the team to investigate and report any safety incidents when installing, operating, or transporting MBESS. Additionally, customers and utility personnel are provided with adequate training to ensure the safe procedure of the MBESS deployment. All these constraints assure the safety aspects of the projects in all operation times and stages.

However, these requirements apply to any generation resources that will be used at customer sites, and as a result, MBESS is not providing any specific added benefit in this area. To this end, the project focused on evaluating the additional benefits associated with MBESS in the other categories presented in Figure 5-1 while, same as any other generation resources. It complied with all the applicable codes and standards for safety.

Appendix A lists safety and operational standards that the MBESS selected for this module complies with.

Improved Reliability and Power Quality

The MBESS provides excellent opportunities for localized reliability enhancement by preventing planned and unplanned outages and providing alternative solutions for customers requiring emergency supplies. In addition, the MBESS can be used to improve power quality issues at sites with known problems such as over/under voltages, flicker, and/or excessive reverse flow.

Reduce Greenhouse Gas (GHG) Emissions

The GHG emission reduction is a key benefit associated with MBESS because this device can replace diesel generators as a clean and quiet sustainable solution.

In addition, the energy storage system can reduce the need for electric generation by reducing the losses across the system, storing energy from renewable sources during off-peak hours, and offsetting consumption during periods where higher-emission sources would be required.

Lower Operating Costs and More Efficient Use of Customer Monies

Energy storage systems can flatten the profile and reduce peak load durations. This will shift utility-delivered consumption to lower-cost periods, which in turn reduces the operating costs for the customers

Additionally, utilizing energy storage systems can defer or eliminate certain utility infrastructure investments and ultimately mitigate potential rate increases.

Economic Development

A sustainable and clean source of low-cost, high-quality, and reliable electric power is essential to economic development in California. The potential energy and cost savings from avoided procurement and generation costs, peak load reduction, and customer bill savings can also contribute to economic development within the state.

Disadvantaged Communities (DACs)

Replacing diesel generators in disadvantaged communities with a clean system, such as the MBESS, can significantly reduce GHG emissions and benefit these communities.

5.2.2 Initial Selection of Metrics

This report section presents a list of selected metrics used throughout the project to evaluate the system's successful operation. These parameters are either generic or use case-specific.

Table 5-2. Selected Metrics for MBESS Benefit Analysis

Metrics	Definition	Unit
Change of State of Charge (ΔSOC)	The degree to which the battery SOC has been changed compared to the SOC at the beginning of the test.	%
Minimum/maximum effective SOC	The minimum/maximum SOC that the MBESS can reach without derating the output power (reducing discharge rate).	%
Available full charge capacity	Total energy charged (kWh) from minimum to maximum SOC.	kWh
Available full discharge capacity	Total energy charged (kWh) from maximum to minimum SOC.	kWh
Actual energy	Present value of the energy capacity of the MBESS. Actual energy capacity is also called "remaining energy capacity."	kWh
Cumulative charge (total)	The real energy is absorbed from the grid by MBESS during the device's lifetime.	MWh
Cumulative discharge (total)	The real energy is injected into the grid by MBESS during the device's lifetime.	MWh
Throughput (daily, monthly, annually)	The cumulative battery discharge and charge amount during a specific duration (kWh).	kWh
MBESS availability	Percentage of the time that the MBESS can respond to a signal and perform any target application (excluding the scheduled maintenance time).	%
Response time	The total time the MBESS system needs to reach the state where the power at Point of Interconnection comes to (and stays) within a certain accuracy band of the target value (for example, within 2%) after an internal or external trigger (such as a setpoint command or a grid event).	ms
Cost of outages	Costs associated with unserved business and missed opportunity for economic gain.	$/kWh
SDG&E Service Territory Emissions Factor	The amount of CO_2 emissions per MWh generated energy within SDG&E service territory.	$MTCO_2e$ /MWh
$MTCO_2e$/MWh	The amount of CO_2 emissions per MWh generated energy by diesel generators.	$MTCO_2e$ /MWh
The upfront cost for MBESS	The total initial cost for employing the MBESS in a system includes transportation, maintenance, etc.	$

Throughout the operation of the MBESS, key parameters of the system were monitored, measured, and recorded by the internal datalogger of the MBESS. **Table 5-3** presents the list of logged data, the designated data category (e.g., measurement, status, alarms), and the devices providing the information (source).

Table 5-3. Required Monitoring Data for MBESS

Data Source	Data Category	Register List
Battery Management System	Measurements/Status	Cell level voltage
		Cell level temperature
		String level current
		String level SOC
		Remaining capacity
		Battery Health
	Alarms	Overvoltage
		Undervoltage
		Over-temperature
Power Conversion System (PCS)	Measurements/Status	AC voltage
		AC current
		Operation mode
		Inverter health
	Alarms	Over-voltage
		Over/under frequency
		Loss of main voltage
		Communications failure
		Inverter failure
Onboard Controller	Measurements/Status	Temperature
		Humidity
		Smoke detector status
		Gas detector status
		HVAC status
	Alarms	Over-temperature
		Under-temperature
		Smoke detection
		Gas detection
		HVAC failure
	Data Analytics	SOC
		Remaining capacity

Data Source	Data Category	Register List
		Cumulative charge
		Cumulative discharge
		Full and partial cycle charges
		Container health

5.2.3 Initial Benefit Estimate and Value Proposition

One of the key objectives of the MBESS demonstration was to determine its value proposition and quantify its benefits. This information will support making investment decisions relative to the prospective commercial adoption of MBESS.

In this regard, a comprehensive cost-benefit analysis was carried out to reveal the significance of employing the MBESS for primarily PSPS outage management use cases and other use cases identified in Section 5.1. Throughout this project, five major steps were taken to evaluate the benefits associated with the MBESS as follows:

1. Developing a list of viable use cases for single-phase MBESS.
2. Establishing a baseline for MBESS utilization and benefit calculation method based on the stacking of multiple use cases.
3. Calculating the benefits and cost of the MBESS for baseline to determine benefit-cost ratio (BCR) and investment rate of return (IRR), the results associated with this step are presented in this section.
4. Performing demonstration of use cases at pre-selected sites to gather real field data associated with each use case.
5. Projecting the data from the demonstration to annual operation over the effective life of the MBESS to verify the baseline with new BCR and IRR. The results associated with this step are presented in Section 6.2.

Assumptions and Approach

The following key assumptions are considered for baseline analysis:

- The MBESS is connected Behind-the-Meter (BTM) and can be operated parallel with the grid for certain use cases.
- The nameplate rating of a unit used for the estimate is 100 kW, 1000 kWhac (End of Life (EOL)), 120/240V, single-phase.
- The effective life is 10 years, based on 150 full cycle charges per year, or 150 MWh throughput.
- The typical PSPS duration is 72 hours, and customers are notified (maximum 10 days and minimum 1 hour in advance), giving enough time to roll out an MBESS to a critical customer site [1].
- The MBESS is utilized for use cased identified in Section 5.1.

Additional assumptions were made regarding the MBESS unit utilization throughout the year. Figure 5-2 demonstrates a high-level overview of seasonal stacking of use cases. This has been assumed based on the following:

- Most PSPS events occur during peak season in the fall/winter months.
- Peak load occurs in the summer months, while there is also the chance of unplanned outages.
- The maintenance program is scheduled for low-activity seasons.

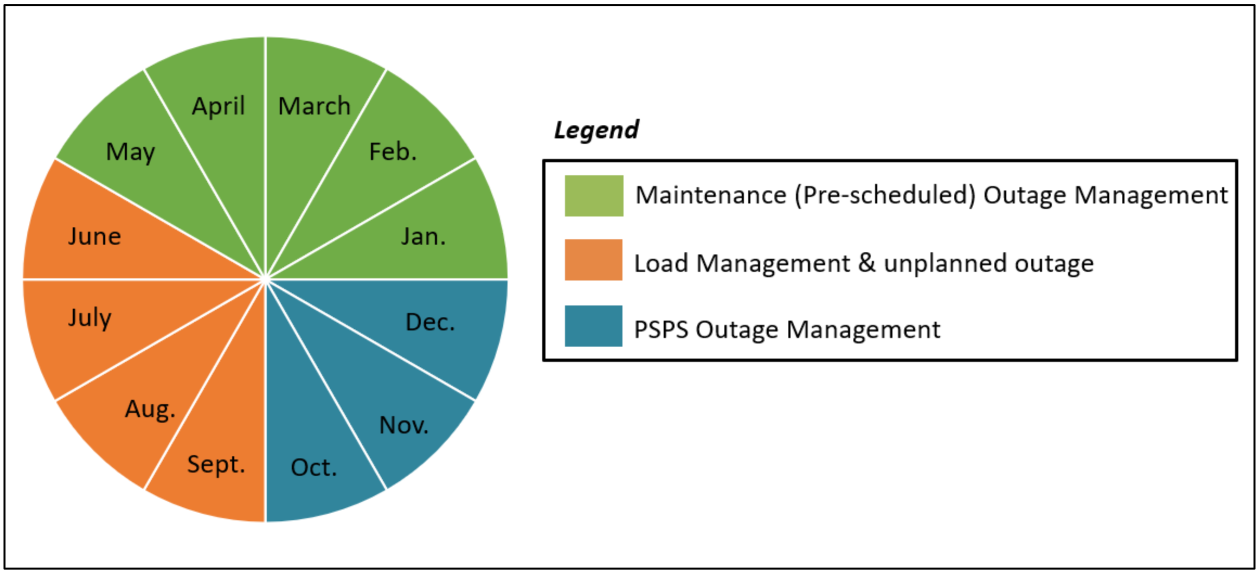

Figure 5-2. High-Level Overview of MBESS Utilization

Based on the general utilization described, assumptions were made regarding the number/duration of outages and the load profile during different seasons. The table provides a summary of these assumptions.

Table 5-4. Summary of Use Case Assumptions

#	Use Case	Assumption
1	Planned outage management for PSPS support	The fall season, 3 outage events, up to 72 hours
2	Unplanned outage management	3 outage events, maximum 4 hours each
3	Maintenance outage management	Avoiding 4 hours of outage associated with a maintenance program for up to 8 customers per 50 kVA service transformer; up to 2 maintenance events are scheduled per day; 4 days per week, 20 weeks per season

#	Use Case	Assumption
4	Load management (at a customer location or a service center)	Charge in super off-peak time (12 AM to 6 AM), discharge in peak time
5	Voltage management for feeder ends	Assumed soft benefit for the system during low activity seasons

Finally, assumptions were made regarding the CO_2 emissions content associated with SDG&E service territory and diesel generator as well as the cost of an outage based on the noted references:

Table 5-5. Assumptions on Carbon Emission and Cost of Outage. $MTCO_2e$ is metric tons of carbon dioxide emissions.

Parameter	Value
SDG&E Service Territory Emissions Factor ($MTCO_2e$/MWh) [2]	0.1362
Diesel Generator ($MTCO_2e$/MWh) [2]	0.4176
Cost of Outage ($/kWh) [4]	9

The following sections describe the procedure for estimating initial benefits in each benefit area identified in Section 5.2.1.

Improved Reliability and Power Quality

Utilizing the MBESS provides an opportunity for preventing planned and unplanned outages and increasing localized reliability and power quality. To quantify these benefits, the following approach was proposed and followed for initial baseline analysis and updated baseline analysis after demonstration:

1. Tracked number of hours and percentage of time that mobile battery was connected and available to provide backup power.
2. Tracked number of outages supported, duration of these outages, the amount of backup power provided, and the duration of any charging activities.
3. Assessed whether the mobile battery adequately supported a site during the entire emergency event.

Table 5-6 lists the desired targets for baseline based on the defined metrics and the projected annual savings associated with this area based on the initial assumptions. It should be noted that during the demonstration of the project, the assumptions were updated based on the actual information considering both CRCs.

Table 5-6 Desired Targets Based on Defined Metrics for Improving Reliability and Power Quality

Metric	Target
Avoided number of PSPS outages	3 (216 hours)
Avoided number of unplanned outages	3 (12 hours)
Avoided number of maintenance outages	160 (5120 hours)
Avoided customer outage duration	5348 hours
Load served during the outage	35,762 kWh
MBESS availability	98%
Cost of outages	$9.00/kWh
Annual savings from outage mitigation	**$321,858**

For evaluation of benefits in reliability/power quality improvement:

- The technical capability of the MBESS to successfully supply the load during an outage is captured through metrics such as availability percentage and several avoided outages and kWh load served.
- The financial revenue generated associated with avoided outage costs is captured.

As summarized in **Table 5-6**, assuming $9.00/kWh cost of the outage and a total of 35,762 kWh load-serving during the outage, the baseline analysis estimates approximately $322k in annual savings from outage mitigation.

Reduce Greenhouse Gas Emissions

One of the key benefits of the MBESS is to provide a clean alternative for diesel generators. Noticeably, lessening the role of diesel generators will reduce greenhouse gas emissions. To evaluate the benefits associated with reduced GHG emissions, the following steps were taken during the baseline and demonstration phases of this EPIC project:

1. Captured and tracked the evaluation metrics, including:
    a. The number/duration of outages
    b. The amount of backup power provided
    c. The duration/amount of battery charging activities and associated electricity charges
2. Estimated the GHG emissions resulting from battery charging operations using the latest annual emission intensity factor for SDG&E.
3. Estimated the equivalent emissions of GHG and other air pollutants resulting from a diesel generator alternative.

Table 5-7. summarizes the baseline target values for CO_2 reduction based on the defined evaluation metrics.

Table 5-7. CO_2 Reductions Considering System Loading

Metric	Target
Total kWh (stacked application)	35,762
Total duration	5,348 hours
Total kWh (stacked application), excluding maintenance	3,762
Total duration	228 hours
CO_2 reduction in PSPS	0.890 $MTCO_2e$
CO_2 Reduction in an unplanned outage	0.168 $MTCO_2e$
CO_2 Reduction in the maintenance	13.365 $MTCO_2e$
Total CO_2 reduction ($MTCO_2e$)	**14.423**

The MBESS operation leads to a total CO_2 reduction of 31772.44 lbs. per annum based on initial analysis.

Lower Operating Costs and More Efficient Use of Customer Monies

Another key area of investigation while considering new technology is evaluating its financial feasibility specifically compared to other alternatives. In this initial analysis, the costs/savings associated with both MBESS technology and an alternative diesel generator is estimated to assess the financial business case:

1. Tracked the costs associated with a mobile battery and the appropriate diesel generator alternative, including up-front equipment costs, lease or rental costs, up-front setup and administrative costs, transportation costs, fuel costs, and other operations and maintenance costs.
2. Performed financial analysis for the business case that compares the battery and diesel solutions and estimated key financial performance metrics such as return on investment, internal rate of return, and complete life cycle costs.

Table 5-8. summarizes the results of initial analysis and metrics associated with overall upfront costs, operating costs, total savings as well as IRR percentage for both technologies. The IRR for both investments is close which implies that the MBESS is a compatible option from financial perspective, although it is a recent innovation of technology, if it is utilized efficiently for use cases defined earlier. It should be noted also that in this analysis soft benefits of environmental impact (e.g., emission/noise reduction), societal impacts and others are excluded.

Table 5-8. Desired Targets Based on Defined Metrics for Lowering the Operating Costs

Metric	Target
The upfront cost for MBESS	$750k
Annual operating cost for MBESS	$95.50k
Annual savings for all use cases	$346.10k
Upfront cost for diesel	$30k
Annual operating cost for diesel	$4.20k

Metric	Target
IRR for MBESS	33%
IRR for diesel	35%

It should be noted that the IRR calculation for MBESS is developed based on use cases described previously. It has been calculated for a 10-year project lifetime. The total saving estimated for all use cases is $346,113.00 (savings from outage management PSPS, maintenance, and unplanned scenario is $321,858.00 plus the saving in the load management, which is $24,255.00). Considering the saving and the total cost, the benefit to cost ratio has a value of approximately 2.03 which states that the benefit is more than twice all the costs associated with the MBESS. **Table 5-9** summarizes parameters associated with a cost-benefit analysis for the MBESS.

Table 5-9. Benefit to Cost Evaluation for Deploying the MBESS

Parameter	Value
System rating	100 kW
72-hour load	1054 kWh
Load serving duration	72
Project lifetime	10 years
Capital cost	$750,000.00
Total utilization	40262 kWh
Operation cost per kWh	$2
Operation cost per kW	$150
Annual capital cost	$75,000.00
Annual operation cost (variable)	$80,524.00
Annual operation cost (fixed)	$15,000.00
Annual savings	$346,113.00
Benefit to cost ratio	**2.03**

Economic Development

This benefit area considers MBESS's impacts on minimizing power outages and increasing economic attractiveness for the businesses. The approach for quantifying benefits in this area is as follows:

1. Performed a survey of affected businesses/communities to assess the project's impact on affected communities and their local businesses.
2. Determined the population within a 1-mile radius of the CRC to evaluate the expected number of people that would have access to the CRC during an outage.
3. Determined number and type of businesses within one block around the CRC that would be visited by people coming to CRC.

Table 5-10 summarizes the metrics captured for baseline. For estimating the business gain associated with serving the population during outages, $590.08 is assumed as the cost of outage for a small commercial and industrial (C&I) customer. The overall business gain and economic improvement estimated is at 17,702.4 USD.

Table 5-10. Desired Targets Based on Defined Metrics for Reducing Greenhouse Gas Emissions

Metric	Target
Number and duration of outage events	228 hours
The average population within 1 mile	105
Number of businesses within 1-block of CRC (direct benefit)	5
Estimate for business gain	**$17,702.4**

Disadvantaged Communities (DACs)

One of the potential benefit areas identified early in the project was serving disadvantaged communities and supplying them utilizing the MBESS during outages. The MBESS can be operated within disadvantaged communities, achieve GHG benefits that support state goals, and reduce emissions from sources located within these communities.

The following approach was proposed for quantifying the benefits:

1. Tracking the number of operating hours and percentage of operating hours that the mobile battery operates within a disadvantaged community.
2. Tracking the total project investment amount and the prorated investment amount associated with operations within the disadvantaged community.
3. Calculating the total GHG emissions impact of the project and the prorated GHG impact associated with operations within the disadvantaged community.
4. Calculating any GHG emission impact from sources located within the disadvantaged community.

Table 5-11 summarizes the proposed metrics to perform the initial baseline analysis. However, the initial target values could not be established due to a disadvantaged community's lack of operating the MBESS under this module. It is noteworthy to mention that none of the CRCs within SDG&E territory are currently located in a DAC. The associated benefits of utilizing MBESS within DACs would benefit from further investigations by the industry.

Table 5-11. Metrics Table for Capturing DAC Advantages

Metric	Target
Outage duration for a DAC CRC	Opportunities will be investigated

Metric	Target
Capital investment for DAC CRC specific to this project	Opportunities will be investigated
Investment for operation cost	Opportunities will be investigated
Avoided cost of using diesel genset	Opportunities will be investigated
Avoided GHG emission by not using diesel genset	Opportunities will be investigated

Incremental Benefits of a Mobile Solution

This project aims to achieve incremental benefits over the diesel generator alternatives. The incremental benefits are compared with incremental costs to determine a return on investment for the MBESS solution. The metrics associated with incremental benefits of the MBESS consider financial evaluation of benefits the MBESS provides beyond what a mobile diesel generator can offer. The use cases that the MBESS can perform beyond a mobile diesel generator are load management and maintenance outage management. It has been assumed that the MBESS is only utilized for incremental use cases to calculate the operating costs and savings. The following approach establishes metrics:

1. Tracked the incremental benefits achieved with the mobile battery over the appropriate diesel generator alternative.
2. Tracked the costs associated with a mobile battery and the appropriate diesel generator alternative.
3. Evaluated an incremental return on investment (ROI) by considering incremental benefits and incremental costs.

The evaluation metrics and target values are summarized in **Table 5-12.** Based on the incremental ROI calculated (30%), MBESS provides considerably high benefits beyond the mobile diesel generator.

Table 5-12. Desired Targets Based on Defined Metrics for Incremental Benefits of A Mobile Solution

Metric	Target
Incremental benefits of MBESS (annual)	\$312,255
Incremental costs of MBESS (annual)	\$84,250
Interest rate	6.5%
Incremental ROI	**30%**

5.3 Description of Pre-Commercial Demonstration

A pre-commercial demonstration of the MBESS was performed at two separate CRC sites, i.e., Dulzura and Pine Valley. The primary use case for both demonstrations was outage management. The following subsections provide more details regarding the demonstration at each site.

5.3.1 Location

CRC 1: Dulzura CRC

Address: 1136 Community Building Road, Dulzura, CA 91917

Figure 5-3 shows a photo of the MBESS at this site during the first demonstration. **Figure 5-4** shows the connection of the MBESS to the CRC through the permanent connection box located at the side of the building. Additionally, as can be seen from this picture, during the demonstration period, an independent Drantez meter was used to verify the data reported by MBESS.

Figure 5-3. Picture of the MBESS in Front of the Dulzura CRC for Demonstration 1

Figure 5-4. MBESS Connected to the Permanent Connection Box at Dulzura CRC

CRC 2: Pine Valley CRC

Address: 28890 Old Highway 80, Pine Valley, CA 91962

Figure 5-5 shows a photo of the MBESS at this site during the second demonstration, while **Figure 5-6** presents the connection of the MBESS to the CRC through the permanent connection box located at the side of the building.

Figure 5-5. Picture of the MBESS in Front of the Pine Valley CRC for Demonstration 2

Figure 5-6. MBESS Connected to the Permanent Connection Box at Pine Valley CRC

5.3.2 Use Case Demonstration

During this EPIC project, the outage management use cases were demonstrated at both CRCs, and relevant data was captured.

5.3.3 Equipment Requirements

In addition to the MBESS system itself, the following equipment requirements for demonstration of this EPIC project at each CRC were:

- **Permanent connection box:** this is required on the utility/customer side to establish an interconnection point to the MBESS at the CRC building for each site.
- **Cam-Lok cables:** A set of 400 A Cam-Lok cables were needed for connecting MBESS to the CRC permanent connection box. It should be noted that proper Cam-Lok cables are located inside MBESS to accelerate the interconnection process.
- **Auxiliary cables:** A set of auxiliary cables to connect to the 120/240V auxiliary input. These cables are also located inside the MBESS terminal box. Please note that during the demonstration portion of this project, at CRC 1, the device utilized internal auxiliary power. In contrast, the auxiliary power required for the operation of the MBESS at CRC 2 was directly supplied from the grid using the terminal box available at the site.

It should be noted that there have been minimal equipment requirements for interconnection of the MBESS to utility/customer facility considering the fully integrated design of MBESS.

5.3.4 Software Requirements

A robust onboard monitoring and control platform is implemented in the MBESS, which has all the required software associated with the operation and monitoring of the unit. There is no additional software required on the utility/customer side.

5.3.5 Supporting SDG&E Infrastructure and Data Requirements

Based on the defined use cases for the MBESS, the following infrastructure and data requirements from SDG&E were proposed originally:

- SCADA integration to the MBESS through Cybersecure access point accommodated in the MBESS
- POI breaker status information (to be utilized for detection of operation mode in automatic as grid-connected or islanded)
- POI power flow information (active and reactive power) for load management application

It was decided to perform all controls locally and avoid the SCADA integration part for demonstration purposes. Thus, remote control, which should be performed through SCADA, was not tested and verified. As part of the demonstration, no communication infrastructure and data were required from the SDG&E side.

5.3.6 Factory Acceptance Testing

Factory Acceptance Test of the MBESS was performed at Quanta Technology's testing laboratory before transporting the unit to SDG&E. The focus of FAT was on functional verification and type test of MBESS (capacity test, efficiency test, and response time). **Table 5-13** summarizes the test categories performed during the FAT and the overall pass/failure based on expectations on MBESS performance on each test category. The first category of tests (inspection and energization) evaluates individual components of the unit by inspecting the overall system verifying the health of the components, and then proceeding with the preparation of the system and energization. The application testing validates control and monitoring features of the MBESS for different modes of operation and applications. The anti-islanding test verifies the inverter anti-islanding performance in disconnecting from the grid upon detection of an outage.

Table 5-13. FAT Test Categories and Scenarios

Category	Test Case	Pass/Fail	Date
Inspection and Energization	Setup Overview	☒/☐	09/24/2021
	Setup Walkthrough	☒/☐	09/24/2021
	HMI Operation Review	☒/☐	09/24/2021
	Container Energization	☒/☐	09/24/2021
Local/Manual Mode	Grid-Connected Mode (GCM): P/Q Setpoint	☒/☐	09/24/2021
	Grid-Connected Mode: Load Management	☒/☐	09/24/2021
	Grid-Connected Mode: Volt-VAR Management	☒/☐	09/24/2021

Category	Test Case	Pass/Fail	Date
	Islanded (SAM)	☒/☐	09/24/2021
Anti-Islanding test		☒/☐	09/24/2021

5.3.7 Test System Design

For accurate simulation of the setup at CRCs, a manual transfer switch (MTS) was considered part of the test setup for switching between the generation sources at CRC (i.e., grid connection and MBESS). Two setups were considered to perform all applications, including load management during grid-connected. **Figure 5-7** represents the first setup where the load bank was connected to the MBESS, and the automatic transfer switch (ATS) was switched to Position 1 for performing all grid-connected tests, including:

- HMI operation review
- Container energization
- Grid-connected Mode: P/Q setpoint
- Grid-connected Mode: Load management
- Grid-connected Mode: Volt-VAR management
- Anti-islanding test

The MBESS was then reconnected to input 2 MTS to simulate the system configuration for islanded applications, shown in **Figure 5-8**.

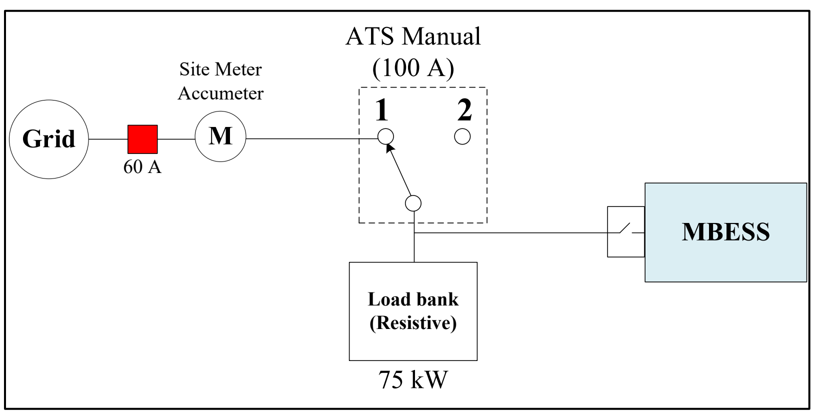

Figure 5-7. FAT Setup 1

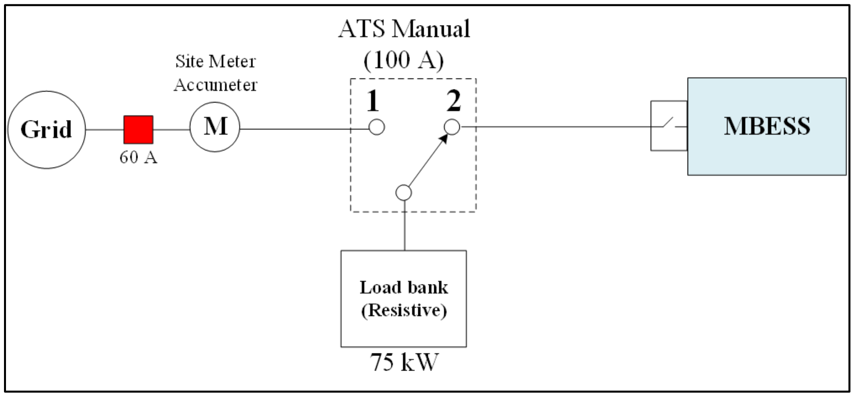

Figure 5-8. FAT Setup 2

5.3.8 Site Acceptance Testing

Site Acceptance Testing of the MBESS was performed in SDG&E Integrated Test Facility at 650 Alpine Way, Escondido, CA 92069. **Figure 5-9** shows a photo of the SAT at the ITF.

Figure 5-9. Photo of the MBESS at ITF during the SAT

During the SAT, a pair of setups were used. The first was for low power grid-connected charge and discharge test, and the second was for high power charge and discharge using a diesel generator and larger load bank. The low and high-power test setups used during the SAT are presented in **Figure 5-10** and **Figure 5-11**, respectively.

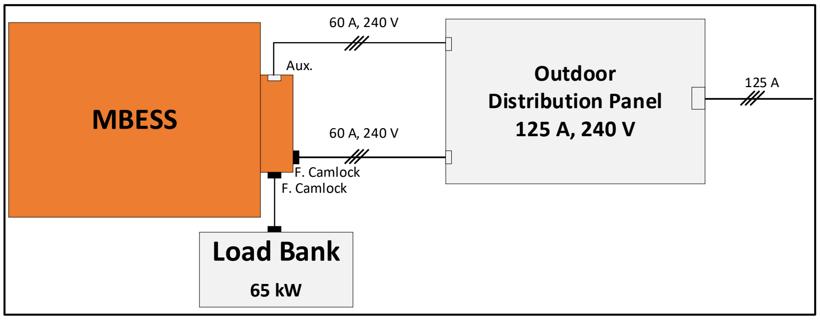

Figure 5-10. Low Power/Current Test Setup Used during SAT

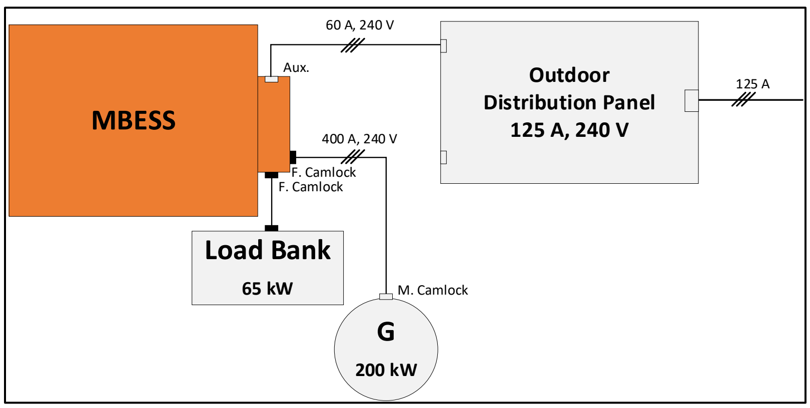

Figure 5-11. High Power/Current Test Setup Used during SAT

Table 5-14 presents a list of performed tests and the results during the SAT of the MBESS at the ITF.

Table 5-14. Test Result List and Summary from SAT of the MBESS at the ITF

SR. No.	Test	Expected Results	Pass/Fail	Date
1	Emergency Stop (E-Stop)	E-Stop operates as intended, and the real power charge drops to 0 kW.	☒/☐	10/15/2021
2	Island Mode—Blackstart Enabled	PCS runs Blackstart to be enabled. The system runs in Island Mode. Adjust setpoints Island remains stable.	☒/☐	10/15/2021
3	Parallel Mode—Four Quadrant Test	Verify MBESS reacts in all quadrants to specified numbers in **Table 7**.	☒/☐	10/15/2021
4	Anti-Islanding Mode—Charge	The system will not island, and PCS will disconnect per IEEE 1547.	☒/☐	10/15/2021
5	Anti-Islanding Mode—Discharge	The system will not island, and PCS will disconnect per IEEE 1547.	☒/☐	10/15/2021

SR. No.	Test	Expected Results	Pass/Fail	Date
6	Uninterruptible Power Supply (UPS)	UPS operates as intended after the loss of power.	☒/☐	10/15/2021
7	Human Machine Interface Login and Command Operation	Successful customer login and command operation.	☒/☐	10/15/2021
8	Roundtrip—Full Discharge	MBESS discharges to 65%.	☒/☐	10/15/2021
9	Roundtrip—Full Charge	MBESS charges 90%.	☒/☐	10/20/2021

5.3.9 Test System Integration

The MBESS selected for this demonstration is designed for frequent relocation and fast interconnection at a new site, using a standard generator terminal box with Cam-Lok plugs. The interconnection aspects at the destination sites are minimal due to the fully integrated design of MBESS:

- Onboard isolation transformer
- Onboard protection device
- Generator terminal box with Cam-Lok connection points
- On-board Cam-Lok and auxiliary cables for connection
- On-board UPS for auxiliary supply during external power disconnection
- Onboard control and monitoring platform with remote access capability

Upon delivery of the MBESS to a new site, the only steps to follow for integration and energization include:

- Complete the inspection checklist for post-delivery, verifying the system has not been damaged in transportation and is ready to be energized
- Connect auxiliary supply feed (if available)
- Connect the MBESS to the permanent connection box using Cam-Lok cables
- Verify the cables are connected safely, energize the MBESS

5.3.10 Execution of Demonstrations

One of the key MBESS technology features, which needs to be evaluated and verified, is its mobility, meaning the MBESS should be relocated from one site to another safely and redeployed quickly at the new site. To evaluate the mobility aspect, the demonstration included the operation of the MBESS at two CRCs within SDG&E's territory. **Figure 5-12** presents a map of the road taken for the transportation of the unit. It shows that the unit was transported safely for approximately 150 miles on local roads throughout this demonstration.

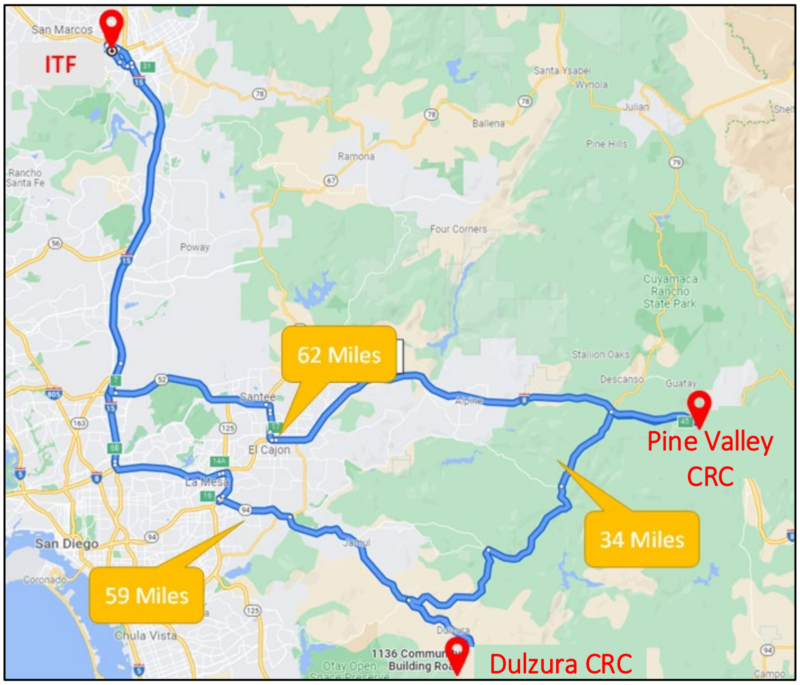

Figure 5-12. MBESS Transportation Map for EPIC Project Demonstrations

Table 5-15 presents the execution steps for the MBESS demonstration. Additional details regarding the results obtained from this demonstration and lessons learned are presented in the following sections.

Table 5-15. Demonstration Schedule of MBESS EPIC-3 Project

Activity	Dates	Comments
Transportation 1	11/03/2021	Between ITF to CRC 1 (59 miles). Transported at full capacity (i.e., SOC = 100%).
Demonstration 1	11/03/2021-11/04/2021	Islanded operation of MBESS at CRC 1 and supplied the total load for approximately 24 hours.
On-site charging	11/04/2021	Upon completing the first demonstration, the unit was put in charge at the site to prepare for the second demonstration.
Transportation 1	11/08/2021	Between CRC 1 to CRC 2 (34 miles). Transported at 80% SOC.
Demonstration 2	11/08/2021-11/09/2021	Islanded operation of MBESS at CRC 2 and supplied the total load for approximately 19 hours.
Transportation 2	11/09/2021	Returning the device to ITF at 30% SOC to complete the demonstration.

Figure 5-13 shows a photo of the MBESS while being transferred from CRC 1 to CRC 2.

Figure 5-13. Photo of MBESS on the Road during Transportation from CRC 1 to CRC 2

5.3.11 Use Case Execution

Among the use cases identified in Section 5.1, the MBESS demonstration focused on PSPS outage management. Due to timeline constraints and other logistical aspects, performing an actual PSPS outage management was impossible. Therefore, the outage management use case was demonstrated through a simulated outage by disconnecting the CRCs from the grid and utilizing the MBESS in islanded mode to supply the full load for each site.

5.3.12 Updated Metrics

Based on the FAT and SAT performed, the originally defined metrics were updated to reflect the change of demonstration plans (including targeted use cases) at both CRCs. **Table 5-16** presents the list of updated metrics.

Table 5-16. Updated Metrics for Demonstration at CRC 1 and 2

Metrics	Unit
Change of State of Charge	%
Minimum/maximum effective SOC	%
Available full charge capacity	kWh
Available full discharge capacity	kWh
Actual energy	kWh
Cumulative discharge (total)	kWh
Throughput (daily, monthly, annually)	kWh
MBESS availability	%

5.3.13 Data Acquisition

One of the key features of the MBESS was its comprehensive data acquisition platform. Data collection is done through onboard monitoring and control platform, and all system data is then logged and captured into a datalogger platform. Throughout the demonstration at CRCs, this data acquisition method was utilized to collect the data for further investigation and analysis. It should be noted that the resolution of the data saved by the data logger is 1 sample every 20 seconds, and a new log file is generated every hour for easy access to logs.

5.4 Data Analysis

Data analysis was performed to support the development of findings, conclusions, and recommendations regarding prospects for commercial adoption. The results of the data analysis have been presented in Section 6.0.

6.0 Project Results

In this section, the results of MBESS testing during several stages of Site Acceptance Testing and demonstration testing have been summarized and presented: in the order of i) SAT at ITF, ii) demonstration at CRC 1, and iii) demonstration at CRC 2. Additionally, the benefit analysis has been updated to reflect demonstration results.

Finally, a list of commercialization activities and associated costs have been described in Section 6.3, and a high-level cost estimate for commercial adoption of the MBESS is provided.

6.1 Results Discussion

6.1.1 Sample Test Results from SAT at ITF

The MBESS was first relocated to the ITF for Site Acceptance Testing. During SAT at the ITF, several aspects of MBESS were tested and verified, as described in Section 5.3.7.

Table 6-1. presents the sample test result for a grid-connected four quadrant operation of the MBESS at ITF during the SAT. The boundaries of the power output were limited to 60 kW because of the load bank size available for testing. **Table 6-1** shows that the MBESS successfully provided the requested active and reactive power at the POI and followed the commanded setpoint for charge/discharge.

Table 6-1. Sample Test Results for Parallel State, Four-Quadrant Operation of the MBESS at ITF during the SAT

Test Commands		Expected Results		Actual Results		Voltage +/- 5% of nominal
P (kW)	Q (kVar)	P (kW)	Q(kVar)	P (kW)	Q (kVar)	L-L/L-N
60	0	60	0	59.46	-0.7	120/120
40	0	40	0	40.9	1.5	120/119
30	0	30	0	30.07	-0.67	119/119
20	0	20	0	20.042	0.55	119/119

Test Commands		Expected Results		Actual Results		Voltage +/- 5% of nominal
P (kW)	Q (kVar)	P (kW)	Q(kVar)	P (kW)	Q (kVar)	L-L/L-N
10	0	10	0	10.188	-0.52	119/118
0	0	0	0	-0.41	-0.55	120/120
-10	0	-10	0	-9.96	0.07	120/120
-20	0	-20	0	-19.76	0.529	119/119
-30	0	-30	0	-29.66	0.128	119/119
-40	0	-40	0	-39.65	-0.16	119/119
-50	0	-50	0	-49.86	-0.11	119/118
-60	0	-60	0	-59.71	-0.45	119/118
-70	0	-70	0	-69.93	0.12	119/118
-80	0	-80	0	-79.93	0.56	119/117
-90	0	-90	0	89.92	0.7	119/117
-80	-10	-80	-10	-79.95	-9.76	119/117
-70	-20	-70	-20	-70.12	-20.05	119/117
-60	-30	-60	-30	-60.083	-29.92	119/117
-50	-30	-50	-30	50.12	-30.34	119/118
-40	-30	-40	-30	-40.51	-30.04	119/118
-30	-20	-30	-20	-30.156	-20.65	119/118
-20	-10	-20	-10	-19.98	-9.99	119/119
-10	-5	-10	-5	-9.98	-5.4	120/119
0	0	0	0	0.002	-0.004	120/120
10	-5	10	-5	9.93	-5.02	119/118
20	-10	20	-10	19.91	-10.22	119/118
30	-20	30	-20	29.99	-19.55	119/118
40	-30	40	-30	40.01	-29.89	119/118
50	-30	50	-30	49.98	-29.81	119/119
60	-30	60	-30	59.98	-30.12	119/119

6.1.2 Sample Demonstration Results at CRC 1

During the demonstration stage at CRC 1, the PSPS outage management use case was tested and verified. The MBESS was utilized in islanded applications to supply CRC 1 load. **Table 6-2** summarizes the overall performance of the MBESS during load supply at CRC 1 demonstration from 8:32 AM (November 3, 2021) until 9:12 AM (November 4, 2021) for a total duration of 24:40 hours.

Table 6-2. MBESS Performance Metrics for CRC 1 Demonstration

Metrics	Unit	Value—CRC 1
Change of State of Charge (ΔSOC)	%	52
Minimum/maximum effective SOC	%	46/98
Available full discharge capacity	kWh	281.26
Actual energy	kWh	250
Cumulative discharge (total)	kWh	149.0
MBESS availability	%	100

Figure 6-1 to **Figure 6-4** present the total active/reactive power at the POI, cumulative injected kWh at the site, and the SOC of the MBESS during the demonstration at CRC 1. During this demonstration, the islanded operation of the MBESS was used to simulate a PSPS outage and verify the operation. It should be noted that generation convention is used for MBESS output, i.e. (i) positive means delivering at POI-discharge for active power and inject for reactive power, and (ii) negative means receiving at POI-charge for active power and absorb for reactive power.

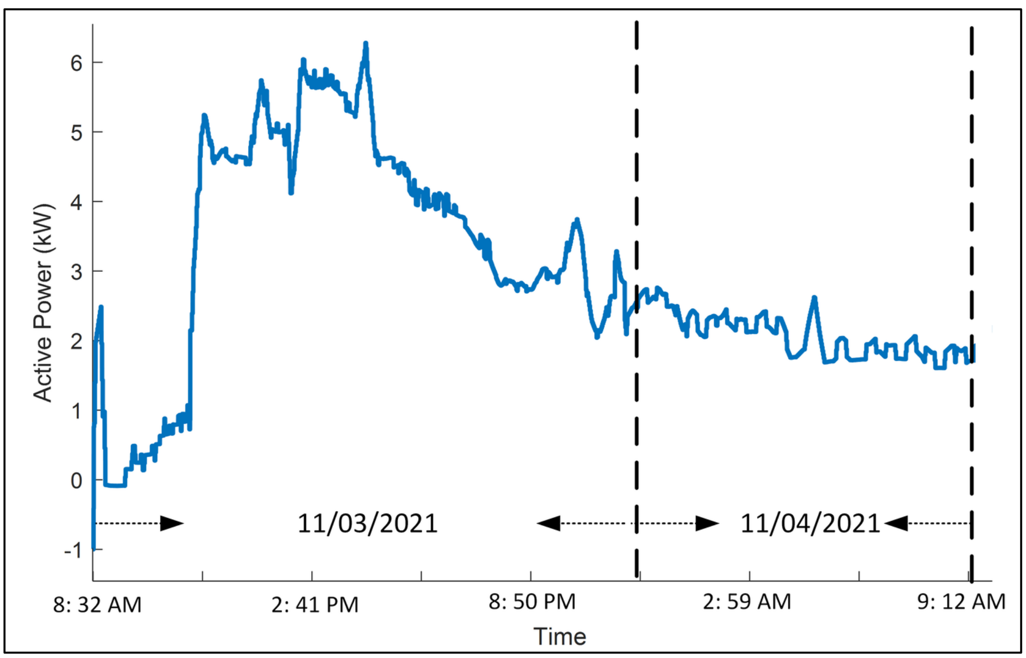

Figure 6-1. kW Supplied by the MBESS at POI at CRC 1

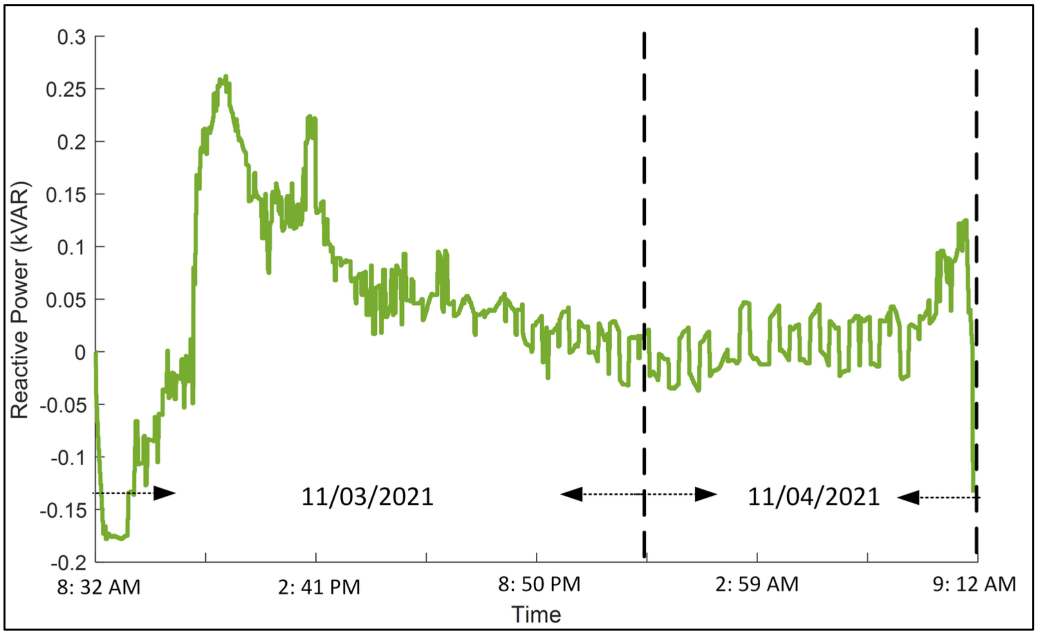

Figure 6-2. kVAr Supplied/Absorbed by MBESS at POI at CRC 1

Based on the total discharged energy (150 kWh) during load supply and the SOC change associated with that (around 52%), the available energy capacity can be estimated at around 280 kWh per one string.

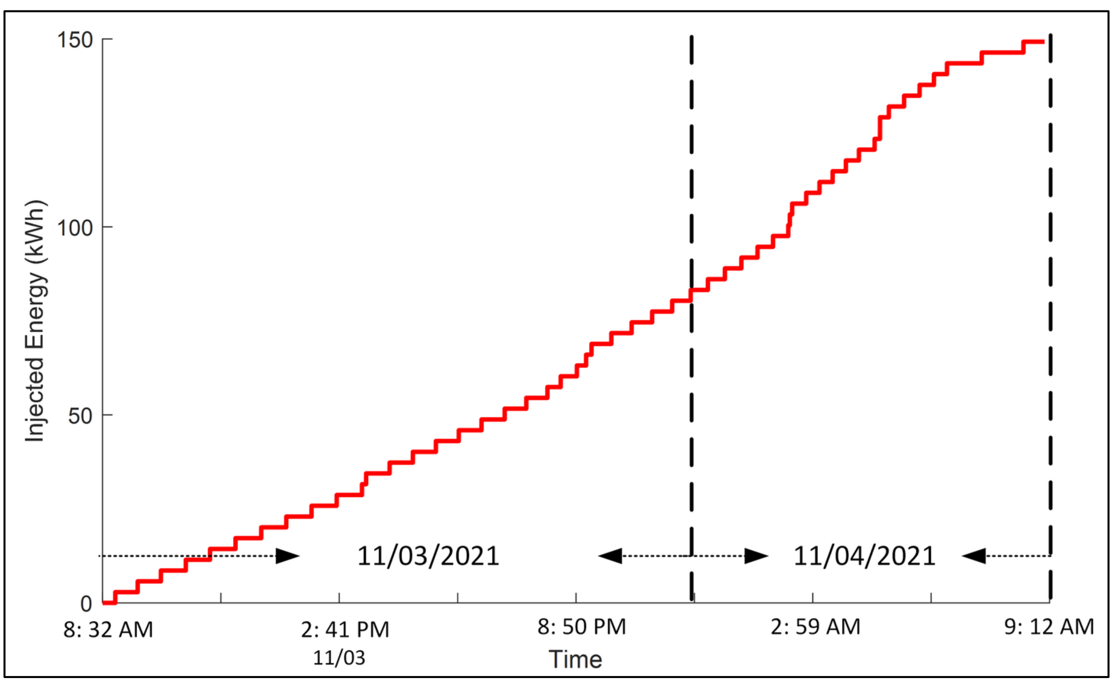

Figure 6-3. Cumulative Injected kWh at POI at CRC 1

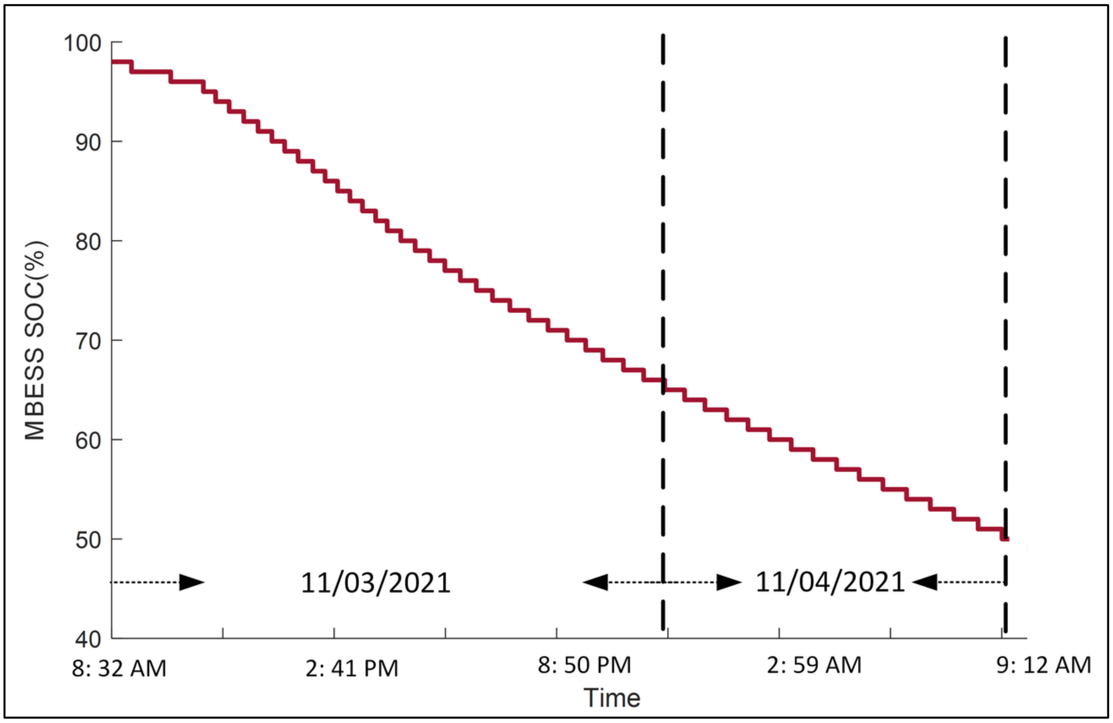

Figure 6-4. MBESS SOC during the Demonstration at CRC 1

It is noted that the voltage and frequency of the island were maintained despite load variations and the MBESS was able to supply the load successfully throughout this demonstration.

6.1.3 Sample Demonstration Results at CRC 2

During the demonstration stage at CRC 2, the PSPS outage management use case was tested and verified. The MBESS was utilized in islanded applications to supply CRC load. **Table 6-3** summarizes the overall performance of the MBESS during load supply at CRC 2 demonstration from 2:30 PM (November 18, 2021) until 9:08 AM (November 19, 2021) for a total duration of 18:38 hours.

Table 6-3. MBESS Performance Metrics for CRC 2 Demonstration

Metrics	Unit	Value—CRC 2
Change of State of Charge (ΔSOC)	%	53
Minimum/maximum effective SOC	%	27/80
Available full discharge capacity	kWh	229.60
Actual energy	kWh	250
Cumulative discharge (total)	kWh	152.1
MBESS availability	%	98

Figure 6-5 through **Figure 6-8** present the total active/reactive power at the POI, cumulative injected kWh at the site, and the SOC of the MBESS during the demonstration at CRC 2.

During this demonstration, the islanded operation of the MBESS was used to simulate a PSPS outage and verify the operation. It should be noted that generation convention is used for MBESS output (i.e. (i) positive means delivering at POI-discharge for active power and inject for reactive power, and (ii) negative means receiving at POI-charge for active power and absorb for reactive power).

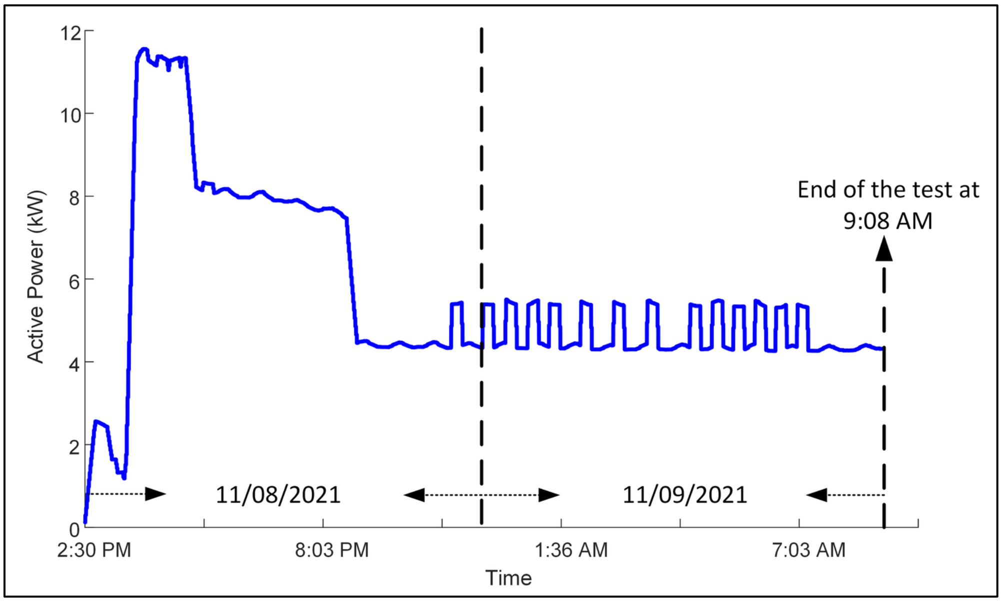

Figure 6-5. kW Supplied by MBESS at POI at CRC 2

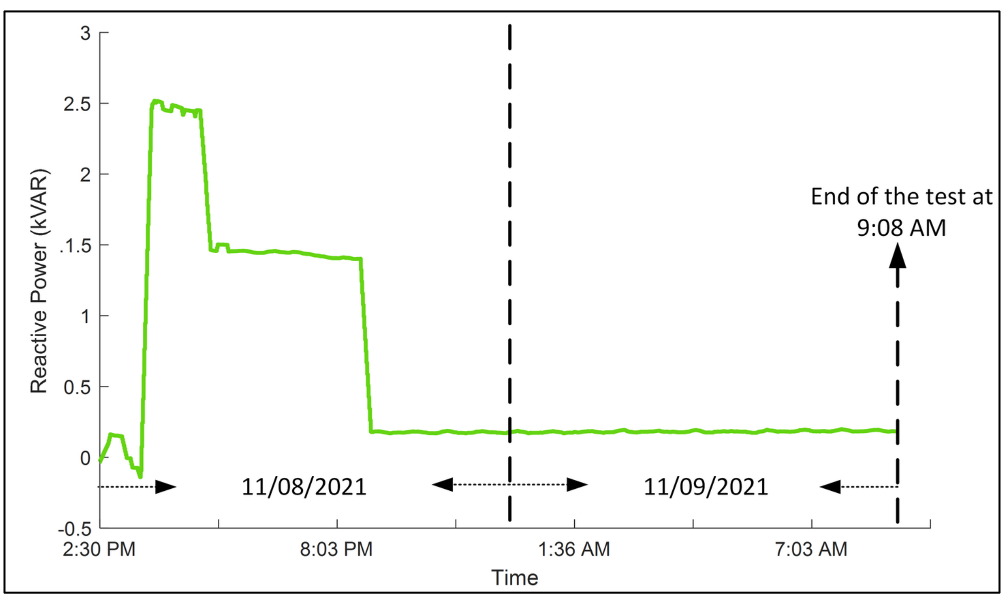

Figure 6-6. kVAr Supplied/Absorbed by MBESS at POI at CRC 2

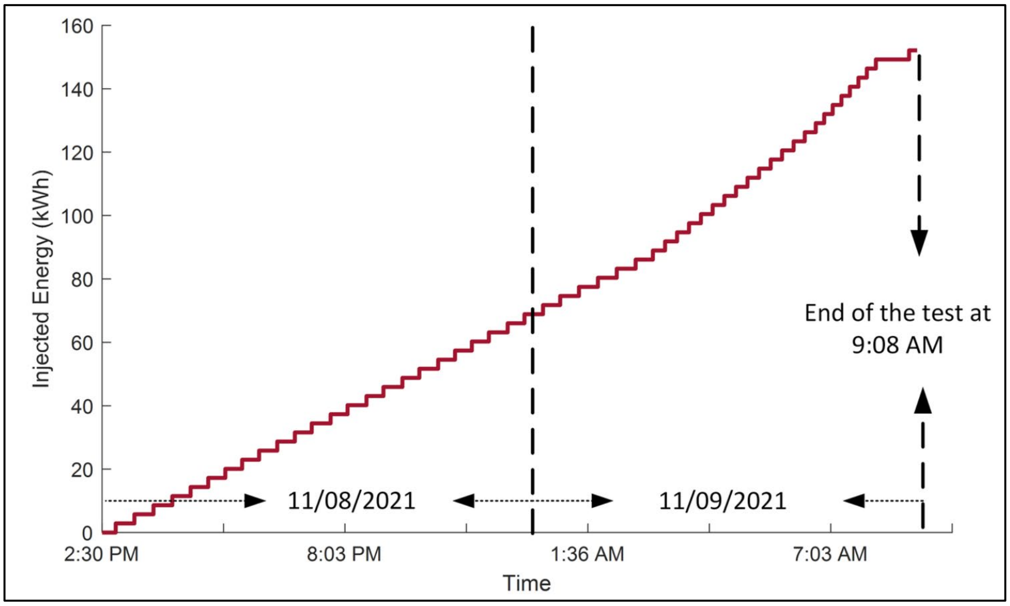

Figure 6-7. Cumulative Injected kWh at POI at CRC 2

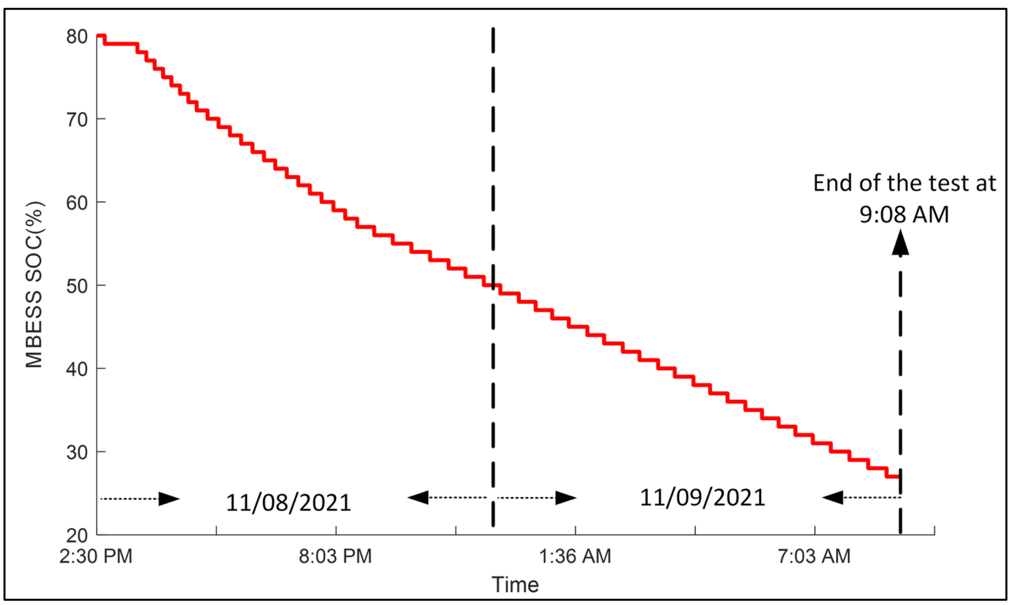

Figure 6-8. MBESS SOC during the Demonstration at CRC 2

6.2 Updated Benefits Analysis

During the demonstration, the MBESS was utilized for PSPS outage management at two different sites. The initial analysis assumed that the MBESS would be utilized for 3 outage events, up to 72 hours of duration, avoiding a total of 216 hours of PSPS outage throughout the year. Based on the field demonstration, the MBESS was utilized for 2 outages with a total duration of 43.96 hours. The MBESS successfully supplied load at CRC buildings during both outages.

It should be noted that the PSPS outage management demonstration performed at both CRCs was simulated and did not reflect the actual utilization for real PSPS events.

Table 6-4. compares initial benefit analysis target values for PSPS outage management with the results from the field. During field demonstration, the number of outages, duration of outages, and the average load deviated slightly from initial assumptions, which explains the difference in overall savings from PSPS outage management. It should be noted that similar saving results will be achieved with originally assumed target values for the number of outages, outage duration, and average load during the outage. Furthermore, successful supply of the load in islanding mode during CRC outages and the transportation of the MBESS from site to site with minimal efforts for interconnection are further proof validating the initial benefit analysis.

Section 7.2 suggests potential enhancements to the utility system by using MBESS commercially.

Table 6-4. Public Safety Power Shutoff Overview Comparison

Metric	Target	Field Results
Number of PSPS outages	3	2
Outage duration	72 hours	43.96 hours
Average load served during the outage	14.64 kW	6.85 kW
Total supported energy during the outage	3162 kWh	301.3 kWh
Saving on avoided cost of the outage	$ 28,458.00	$ 2,711.70

6.3 Commercialization Cost Estimates

Commercialization cost estimates the total cost required to establish the necessary infrastructure and dedicate resources to procure the required equipment, integrate the assets into existing infrastructure, operate and maintain the asset, and manage the overall asset utilization. The following items summarize different categories of commercialization costs each utility may be dealing with when integrating MBESS technology into their fleet. The order mainly follows the life cycle of technology within the utility environment:

- **Product Qualification and Standardization—Group Involved: Standards**
  Setting up an evaluation framework for qualifying the products based on the offered technology. The Standards team needs to prepare guidelines and documentation on deployment and utilizations. In addition, a standard interconnection box for the facilities of interest should be defined and installed.
- **Ownership and Inclusion in Utility Process—Group Involved: DER**
  Assigning the asset ownership to a certain department within utility (or creating a new department to lead the effort) and dedicating resources for scheduling and operation, contractor relationship, customer relationship (if applicable), and overall management of the process.
- **Procurement, Legal, and Permitting—Groups Involved: Engineering and Procurement**

Setting up the procurement process, including specification document development, standard request for proposal (RFP) document, defining business model strategies (purchase vs. lease) and financial setup, setting up warranty and after-sale service contracts, etc. In addition, permitting process should be developed for any required permits, including transportation, siting, etc.

- **Integration to the Control Center—Group Involved: Distribution Operation**
  The MBESS solution needs to be integrated into utility SCADA or another back-office enterprise platform by developing a standard method of communication, standardizing data requirements and data exchange for each location, developing screens for monitoring and control of MBESS, developing cybersecurity requirements, etc.
- **Operation and Maintenance—Group Involved: Fleet Management**
  Dedicating and training resources for the day-to-day operation of MBESS units and maintaining the units over the life cycle of the products. This includes routine inspection and testing of the units and performance tracking and data capture at the utility side, which is required for executing warranty and contractual obligations. Furthermore, developing a fleet management process is part of required responsibilities under the fleet management team (e.g., setting up the fleet space for storing/placing the units on utility premises while not in use and contracting transportation company for towing and relocating the units).
- **Customer Outreach—Group Involved: Public Relations**
  Additional effort should be directed towards communicating the message to the public and industry on technology concepts, value propositions, and differentiation from other technologies.

Table 6-5 summarizes a high-level cost estimate for the commercialization process, assuming a fleet of 10 MBESS is being set up. The labor is calculated based on the duration of activity in months (assuming 120 effective working hours per month for utility staff, with a rate of $100/hr).

Table 6-5. Sample Estimated Commercialization Cost Breakdown

Attribute	Labor Person-months	Expense	Total Estimate	Note
Product Qualification and Standardization	3	$20,000	$ 56,000.00	The expense of standard interconnection box at 10 sites
Ownership and Inclusion in Utility Process	4	$6,000	$ 54,000.00	The expense of offices for dedicated employees (3)
Procurement, Legal, and Permitting	2	-	$ 24,000.00	
Integration to the Control Center	2	-	$ 24,000.00	

Attribute	Labor Person-months	Expense	Total Estimate	Note
Operation and Maintenance	3	$15,000	$ 51,000.00	The expense of additional fleet space and contract fees
Customer Outreach	1	$6,000	$ 18,000.00	The expense of material preparation for public awareness
Capital cost of 10 units (120/240V, 100 kW, 1 MWh)	10	$450,000	$4,620,000	Average price
Total			$ 4,847,000.00	

7.0 Findings

The demonstrations at the two sites clearly showed the viability and value of utilizing a mobile energy storage system for supplying the community centers during a specific time that interruption (outage) is expected. The approach alleviates the need for maintaining a stationary backup generation source at a facility year-round. It also provides a proper alternative for polluting emergency diesel generators. Several aspects of the demonstrations are further emphasized in the findings.

- Connection of the MBESS to the terminal box at each site was performed very smoothly and quickly, with no power interruption for the facility. It did not require any specialized skill or tool. A regular customer can even make the connection by following the instructions.
- Using manual mode, MBESS was started very easily, following a few steps, by pressing the "start pushbutton" on the terminal box. The system status and operation could be checked frequently using a portable monitor (tablet) that provides access to unit HMI.
- There was almost no noise during the unit operation, which is a major advantage of using MBESS, especially at night in a very quiet neighborhood. The unit would have caused extremely troubling noises in the evening and at night with diesel generators.

The unit operation and supplying the facility were successfully demonstrated in both sites for more than 12 hours of an outage with no need to stop or start the unit. With diesel engines, the unit may need to be stopped after 6–8 hours and restarted again to meet the hard duration limitation for emergency use of diesel genset (enforced by local jurisdictions in some places).

7.1 Findings Discussion

Several operating scenarios were investigated during the demonstration, and observations were made to improve the system's overall performance.

- The use of the tablet for user interface and operation monitoring was shown to be not a convenient way of accessing the HMI page. A stationary outdoor-rated HMI device installed at the same location as the pushbuttons on the terminal box should be investigated and applied for future units.
- The unit includes meters and power quality devices inside the container. It was also found that the main power meter is better installed on the unit's exterior and closer to the operation pushbuttons to provide immediate measurement as a way of feedback for the user on the level of power exchange with the facility.
- During a troubleshooting incident, the UPS power was utilized instead of the external auxiliary power source, which caused the depletion of UPS batteries. As a result, the power supply to all control and monitoring systems was disconnected, which led to the loss of access to the system. The instructions were added to the system operation manual to keep the system on external auxiliary power for any troubleshooting procedure.
- During system preparation for energization, the auxiliary power cable was connected incorrectly, which led to the burning of the auxiliary circuit contactor. The contactor was replaced to resolve the issue. The instructions were added to the system operation manual to provide additional instructions on the system preparation and setup.

7.2 Updated Value Proposition

The MBESS demonstration was categorized originally within the EPIC framework category of Customer-Focused Services. The major value propositions for mobile battery solutions are:

1. **Enhanced Reliability and Resiliency:** The most important value proposition of MBESS, which perfectly aligns with the EPIC framework, is outage management for utility customers, which enhances the system's reliability and resiliency. It could be achieved through microgrid applications incorporated into the MBESS controller.

    1.1. **Observations from Demonstration:** MBESS successfully demonstrated the customer supply use case during outage:

    - During islanded application, the MBESS maintains the voltage and frequency of the island and supplies the load up to its rated value.
    - The demonstration was performed for load supply during the outage. Based on the energy capacity of each unit and the customer load profile, the supply duration varies.

2. **Mobility:** One of the main value propositions of the MBESS is the ability to be self-sustained and transported to different locations and quickly be redeployed at a new location. The mobility feature will enhance the value of energy storage systems and leverage geographic versatility benefits.

    2.1. **Observations from Demonstration:** The MBESS successfully demonstrated the mobility aspects:

- The system's design was considered for all the integration components, including isolation transformer and plug-and-play Cam-Lok connection box, which facilitated easy connection to the customer/utility system.
- The overall redeployment and reconnection time at a new facility was less than five minutes.

Currently, the definition of a mobile storage solution is perceived differently across the industry and solution providers. Some of the proposed solutions as mobile storage are rather transportable (meaning that the stationary version can be transported from one location to another). However, such solutions do not offer some features, including:

- Integrated solution with interconnections assets incorporated.
- Plug-and-play terminal connection for fast redeployment at the site.
- 24/7 onboard monitoring and control platform.

It is important to consider these issues in the commercial adoption of MBESS.

3. **Grid Support Functionalities:** One of the areas that the MBESS offers value is the ability to support the grid for services such as power quality improvement (by voltage support) or demand reduction. This is important since the MBESS can stack applications throughout the year and during seasons without expecting outages. It can be utilized for grid support services per utility need.

   3.1. **Observations from Demonstration:** MBESS successfully demonstrated:
   - Grid-connected performance for parallel operation with the grid (charge/discharge).
   - Transfer between different modes of operation.
   - Specific applications such as load management and voltage support.

4. **Situational Awareness:** As a new asset in the utility portfolio, situational awareness over the area of integration becomes another value proposition. The MBESS provides a unique angle to enhancing situational awareness in that it will be deployed to different locations in the system for brief periods. It is expected to enhance integration into distribution system operations and the system operator and, thus, provide greater visibility in the vicinity of the grid to which the MBESS is connected by supplying information such as real and reactive power flow, voltage, frequency, and other key performance indices. The design of the MBESS monitoring and control system will include provisions for data acquisition that create additional value.

   4.1. **Observations from Demonstration:** MBESS successfully demonstrated:
   - System metering at different points.
   - Extensive data logging from different sources of data (battery cells and BMS, power conversion system, inter-tie relay, condition monitoring devices, etc.).
   - System remote access and monitoring.

5. **Societal Benefits:** The MBESS provides a wide range of hard-to-quantify benefits such as reducing GHG emissions, improving public utility image, and knowledge gain for utilities through technology evaluation and implementation. The mobility features of MBESS facilitate charging from different locations and then relocating and supplying the customer load as needed. For instance, co-locating MBESS with a solar site makes it a carbon-free generation source that can significantly lower the amount of GHG compared to traditional portable diesel generators.

8.0 Conclusions

This EPIC project successfully demonstrated the viability of utilizing mobile energy storage solutions for supporting customers during outage events in remote and rural areas of the service territory. The MBESS was able to supply CRC load for an extended time (over 24 hours) at each demonstration site. The MBESS also completed 155 miles of transportation on highways and rural roads when relocating among the three sites.

The new battery technologies based on LFP enable the safe and reliable transportation of the batteries when fully charged and integrated into the power conversion systems. The key concern with safely transporting fully charged battery cells was a limiting factor in developing mobile solutions. The project showed that mobility could be achieved with proper use of the technology and adequate design to incorporate sensors and monitoring and the technical capability for enabling the solutions.

The viability of several use cases for the MBESS was fully evaluated during SAT. The outage management use case was also extensively verified in two real-world MBESS deployment sites, with adequate data gathering to facilitate a detailed performance analysis and benefits assessment.

9.0 Tech Transfer Plan

9.1 Project Result Dissemination

The results of this module of EPIC-3, Project 7, will be published and made available to the general public in this comprehensive final project report, which will be posted on SDG&E's public website and filed with CPUC. This report is the main record of what was demonstrated and learned in the project and is the primary tech transfer tool. The project's results and findings may also be submitted for consideration by industry conference organizers.

Several meetings were held throughout the project design and testing stages involving the stakeholders and subject matter experts from various SDG&E departments. The focus of the meetings was to describe the project progress and obtain feedback or suggestions on various aspects of the use cases and test system development. A shortlist of key meetings is provided below:

- Meeting on the review of the baseline analysis for the use cases and benefit evaluation, during which the methodology for the use case analysis and baseline estimate was presented. The recommendations from various teams were gathered and incorporated in the baseline analysis results.

- Meeting for FAT and SAT setup development to ensure the proposed test setups are comprehensive enough to facilitate various test cases and operating scenarios that would help evaluate the MBESS features and performance.
- Remote witnessing of the FAT and review of the performance.
- An in-person meeting at ITF during the SAT for performing the tests and discussing the results.
- Working session at ITF for knowledge transfer and user training of the operation modes and utilization of the MBESS.

The engagement of these key SDG&E stakeholder groups in these activities supports their ability to engage in commercial adoption processes after the EPIC project ends. Key internal stakeholders to be engaged in post-EPIC activities are:

- Distribution planning
- Advanced technology
- Distribution operations
- Protection and automation
- Information techology
- Customer programs

9.2 Transition for Commercial Use

Presently, the utility industry has a significant interest in learning about MBESS applications and utilization experience. Utility systems are exposed to various natural disasters, and they are looking for mobile solutions that can be reliably deployed in the field to support customers during outage recovery time, yet are environmentally friendly, safer, and less polluting (noise- and emission-wise) in comparison to the conventional diesel generator approaches. SDG&E, based on the results of this EPIC project, has gained firsthand experience with the performance and logistical aspects of the MBESS. The benefit analysis outcome can support business case development for a fleet of MBESS.

10.0 Recommendations

Based on the successful pre-commercial demonstration of the technology and use cases, it is recommended that SDG&E commercially adopt MBESS into their operations. SDG&E would need to designate which business units should be involved in the commercialization process and appoint one business unit to lead. It is suggested that initially, the DER group take the lead to identify applications and coordinate the use of MBESS across SDG&E service territory commercially. The next natural step would be to develop a commercialization plan.

SDG&E needs to form an operation and maintenance (O&M) plan to store MBESS units while not operating at sites. This plan shall address the need for space to park/store these MBESS units, define the requirement for accessing auxiliary power during the park/store time, and the operational procedures for regular charge/discharge of the units while in storage to avoid damage to the batteries.

A fleet of MBESS of different types, capacities, and ratings should be considered. Both purchase and lease options for the MBESS fleet should be considered. The value proposition observed in this Module 2 of EPIC-3 Project 7 and the companion work of Module 1 indicates significant benefits can be derived from the use of MBESS. However, the number of applications addressed in both modules was limited by time and funding in the EPIC project. Additional applications (operating procedures and use cases) need to be investigated during the early stages of commercialization.

Some issues to be considered are:

- The use cases demonstrated in the project were limited to the outage management scenarios due to the configuration at the CRC sites. It is recommended to perform additional testing and evaluation at other potential customer sites to collect and analyze grid supporting use cases such as Volt-VAR or peak shaving. Although those use cases have been verified in the laboratory environment, the real-world deployment and assessment will bring additional knowledge gains, data, and operational learning to refine the value proposition of MBESS solution.
- The MBESS used for this project provides a single-phase output. However, the system can support both single-phase and three-phase applications if they are included in the project's functional specifications. It is recommended that future projects incorporate both types of single-phase and three-phase outputs to support residential and commercial facilities. The multiple output type will increase the coverage and utilization cases for the system.
- Integration to the dispatch center and remote control or observability were not part of the EPIC project. However, remote dispatch and monitoring will be key aspects of the field operation. They should be tested when the mobile solution gains enough traction to acquire multiple units and build a fleet of MBESS.
- Depending on the number of relocations expected, a combined truck-trailer approach may become more beneficial and convenient than a flatbed trailer in support of multiple use cases and utility applications. This can be a modification applied in future systems.

An MBESS can be equipped with electric vehicle chargers for the additional benefit of supporting customers during outage scenarios. A hybrid MBESS with an onboard charger will significantly improve the business case and come at a low incremental cost

11.0 References

1. https://www.sdge.com/wildfire-safety/psps-more-info#psps
2. https://www.sandiego.edu/law/documents/centers/epic/1Electric%20Emissions%20Factor%20Method_061716.pdf
3. https://www.eia.gov/tools/faqs/faq.php?id=74&t=11
4. https://www.icecalculator.com/home

12.0 Appendix A – Standards and Guidelines

#	Name	Definition
1	ANSI	American National Standards Institute
2	ANSI C37/IEEE	Surges withstand capabilities, whenever applicable
3	ANSI C57/IEEE	Transformer Standards, whenever applicable
4	ANSI Z535	Product Safety Signs and Labels
5	ANSI/IEEE C2	National Electric Safety Code
6	Cal/OSHA	California Occupational Safety and Health Administration
7	CFC	California Fire Code
8	Electric Tariff Rule 21	Generating Facility Interconnections
9	IEEE 1547	IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems
10	IEEE 1881	Standard Glossary of Stationary Battery Terminology
11	IEEE 519	IEEE Recommended Practices and Requirements for harmonic Control in Electrical Power Systems
12	NEC	National Electric Code
13	NEMA	National Electrical Manufacturers Association
14	NESC	National Electric Safety Code
15	NFPA 704	Standard System for the Identification of the Hazards of Materials for Emergency Response
16	NFPA 855	Standard for the Installation of Stationary Energy Storage Systems *Applicable in the event of adoption by contract execution
17	UL 1642/IEC 62133	Applicable sections related to battery cell safety, where applicable
18	UL 1741	Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources
19	UL 1778	Underwriters Laboratory's Standard for Uninterruptible Power Systems (UPS) for up to 600V AC
20	UL 9540/9540A	Standard for Energy Storage Systems and Equipment

#	Name	Definition
21	42 United States Code (U.S.C.)	Noise Control Act of 1972