EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-1, Project 1**
Project Name	**Smart Grid Architecture Demonstrations Program**
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Attribution

This comprehensive final report documents the work done in this EPIC project. 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-1, Project 1 (Smart Grid Architecture Demonstrations) was to conduct pilot demonstrations of key candidate prototype components of the SDG&E smart grid architecture to determine their suitability for adoption in the architecture. The demonstration results are intended to be used by SDG&E and other users to aid in selection of architecture components for adoption and to support the implementation phase for adopted components.

This project was one of three SDG&E EPIC projects on pre-commercial demonstration of communications standards for power system operations. The three projects were:

- Smart Grid Architecture Demonstrations
    - Focus: Communications standards for integration of feeder equipment and DER into networked automation
- Monitoring, Communication, and Control Infrastructure for Power System Modernization
    - Focus: Open Field Message Bus
- Modernization of Distribution System and Integration of Distributed Generation and Storage
    - Focus: IEC 61850 in substation network

The principal standard of interest in these three demonstrations was IEC 61850, which is an open standard developed by industry stakeholders and promulgated through the International Electrotechnical Commission. The intent of these EPIC demonstrations is to increase the body of knowledge available to aid users in making decisions regarding their future power system communications architecture. The final reports for all three of these projects are posted on the SDG&E EPIC website at www.sdge.com/epic

Electric utility power systems are becoming increasingly complex. Recent years have seen a rapid and sustained increase in the deployment of intelligent electronic devices (IEDs), with increasing processing capabilities and communication requirements. These trends make it necessary to reevaluate the traditional utility communication models and data architectures. The focus of this project was to examine the options, assess their suitability to address specific needs, and perform pre-commercial demonstrations of promising architecture components.

The project provided an assessment of the current SDG&E distribution operations architecture, with a focus on identifying gaps in existing processes and applications. A number of industry reference architectures were reviewed. The CEN-CENELEC-ETSI[1] Smart Grid Coordination Group's Smart Grids Architecture Model (SGAM) framework was identified as best suited to document the current and proposed architecture necessary to adapt to the changing demands on the system. In addition to looking at reference architectures, the project also examined the status, content, and trends of major utility communications standards and ongoing work by several standard development organizations. The International Electrotechnical Commission (IEC) TC-57 family of communication standards was identified as an open (non-proprietary) platform with existing broad acceptance for substation applications and possible usage in distribution circuits. IEC 61850 is a principal component of the platform that warranted further investigation in the second (demonstration) phase of the project. The

[1] In Europe the standards for safety and quality for product and service are developed and agreed by the three officially recognized European Standardization Organizations: the European Committee for Standardization (CEN), the European Committee for Electrotechnical Standardization (CENELEC) and the European Telecommunications Standards Institute (ETSI).

project furthermore provided a ten-year implementation roadmap on how the proposed changes to the SDG&E architecture could be accomplished.

A test system was constructed, and a total of eleven use cases were defined to demonstrate the use of IEC 61850 standards. The uses cases included tests of the ability of IEC 61850 to integrate substation and feeder devices and perform some of the advanced communications and automation necessary to optimize the use of DER and other IEDs. Other tests were defined to examine the process and organizational impact of utilizing IEC 61850, while others were used to compare IEC 61850 with other protocols, such as DNP 3.0 and OpenFMB[2]. The demonstration showed that IEC 61850 has some unique abilities that offered tangible benefits over current approaches. These include:

- Improved protection systems.
- Enhanced distribution system operations.
- Improved distribution system stability.
- Improved system performance under emergency conditions.

Other use cases demonstrated that correct selection of tools and vendor products can minimize the level of effort and issues encountered, as there are still issues around IEC 61850 interoperability that complicate system integration issues. Improving interoperability and simplifying system configuration are two focus areas for the user community working on enhancements to the standard so continued improvement is expected. The performance of DNP 3.0 and IEC 61850 were found to be comparable when used between substation and simulated utility control center. However, there was a large difference in the performance of IEC 61850 and OpenFMB when used for the same application, with IEC 61850 substantially outperforming OpenFMB because none of the devices tested provided native support for OpenFMB, necessitating the use of protocol converters.

The project demonstrated that IEC 61850 provides real, tangible benefits. It also underscored that the plug-and-play concept envisaged by the creators of the standard remains a work in progress and that constructing an IEC 61850-based system can be challenging, especially when different vendor products are integrated together. However, the benefits far outweigh the challenges, and the adoption of the IEC 61850 protocol should be one of the cornerstones of the new SDG&E architectural construct.

The recommendation is therefore that SDG&E should pursue the operational deployment of IEC 61850 via a pilot project that aside from exploring the operational adoption of the standards, should also be tasked with quantifying costs and benefits to form the basis for developing a cost-benefit analysis for wide-scale deployment, examining the changes to standard operating procedures necessary to fully leverage the benefit of a digital substation, and acting as a training platform for engineering, testing and commissioning personnel.

[2] Distributed Network Protocol, and Open Field Message Bus.

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LIST OF ACRONYMS AND ABBREVIATIONS

BESS	Battery Energy Storage System
CB	Circuit Breaker
CEN	Comité Européen de Normalisation European Committee for Standardization
CENELEC	Comité Européen de Normalisation Electrotechnique European Committee for Electrotechnical Standardization
CIM	Common Information Model
COS	Catalog of Standards
CT	Current Transformer
DCLM	Dynamic Circuit Load Management
DELCAM	Dynamic Emergency Load Control and Management
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DSO	Distribution System Operator
D-SCADA	Distribution SCADA
EPIC	Electric Program Investment Charge
ETSI	European Telecommunications Standards Institute
FAT	Factory Acceptance Test
GID	Generic Interface Description
GOOSE	Generic Object-Oriented Substation Event
GWAC	GridWise Architecture Council
IEC	International Electrotechnical Corporation
IED	Intelligent Electronic Device
IOP	Interoperability Test
ITF	Integrated Test Facility
kW	Kilowatt
LTC	Load Tap Changer
MMS	Manufacturing Messaging Standard
MQTT	Message Queueing Telemetry Transport
OpenFMB	Open Field Message Bus
PHIL	Power Hardware in the Loop
PT	Potential Transformer (aka Voltage Transformer)
RACI	Responsible, Accountable, Consulted and Informed
RAMCO	Regional Aggregator, Monitor, and Circuit Optimizer
RFP	Request for Proposal
RTDS	Real Time Digital Simulator
RTU	Remote Terminal Unit
SAT	Site Acceptance Test

SCADA	Supervisory Control and Data Acquisition
SDG&E	San Diego Gas and Electric
SDO	Standards Developing Organization
SGAM	Smart Grids Architecture Model
SGIP	Smart Grid Interoperability Panel
TE	Transactive Energy
TOGAF	The Open Group Architecture Framework
UCA IUG	Utility Communication Architecture International Users Group
VR	Voltage Regulator

1 INTRODUCTION

1.1 Objective

This project was one of three SDG&E Electric Program Investment Charge (EPIC) projects on pre-commercial demonstration of communications architecture for power system operations. The three projects were:

- Smart Grid Architecture Demonstrations (EPIC-1, Project 1)
  - Focus: Communications standards for integration of feeder equipment and DER into networked automation
- Monitoring, Communication, and Control Infrastructure for Power System Modernization (EPIC-2, Project 3)
  - Focus: Open Field Message Bus
- Modernization of Distribution System and Integration of Distributed Generation and Storage (EPIC-2, Project 1)
  - Focus: IEC 61850 in Substation Network

The principal standard of interest in these three demonstrations was International Electrotechnical Commission (IEC) 61850, which is an open (non-proprietary) standard developed by industry stakeholders and promulgated through the IEC. IEC 61850 is part of the IEC TC-57 family of open communications standards for power systems. The intent of these EPIC demonstrations was to increase the body of knowledge available to aid users in making decisions regarding their future power system communications architecture. The final reports for all three of these projects are posted on the San Diego Gas & Electric (SDG&E) EPIC website at www.sdge.com/epic. This body of work was limited in scope by funding availability in the SDG&E EPIC program, and it is acknowledged that a much larger body of work in this area is needed.

This report is the comprehensive final report for the first project listed above. This project was chartered to perform a pre-commercial demonstration of smart grid architecture components to serve as a blueprint for future distribution system development. "Smart grid" is a vague term that means many different things to different individuals, and its popularity is therefore waning due to the confusion it causes. For purposes of this report, when it is necessary to use the term, it is intended to mean advanced distribution system automation.

The specific objectives of this program were to:

- Perform pilot demonstrations of key candidate prototype building blocks of the SDG&E smart grid architecture to determine their suitability for adoption in the architecture;
- Document the results and make recommendations on whether specific building blocks should be adopted; and
- Provide demonstration results to the SDG&E interdepartmental smart grid architecture team to support the implementation phase for any building blocks adopted.

1.2 Issue/problem being addressed

Electric utility power distribution systems are becoming increasingly complex with the integration of intelligent electronic devices (IEDs). As a result, a more advanced system architecture is needed that can be easily assimilate the new IEDs, have low latency, and be standardized among vendors. The communication architecture including protocols, object models and related standards should be compatible with the electrical system configuration. With new IEDs being introduced in the electrical system, the communication standards for device information models and protocols must ensure necessary information transfers are done to properly operate the more complex system. The new smart grid architecture must address the information exchange requirements for both actual operations of the physical smart grid and for the business transactions associated with those operations.

One type of IED that is seeing very rapid growth on utility systems is distributed energy resources (DER). The increased DER penetration creates unique challenges, such as two-way power flow, changes in system protection practices, and voltage regulation considerations. There is an industry need for demonstrations of advanced communications architecture that would enable the information exchange among the growing number of devices in increasingly complex utility systems.

1.3 Project description, tasks, and deliverables produced

To enable the development of new smart grid architecture, this project focused on investigating and demonstrating architectural constructs to aid SDG&E and the industry in decisions regarding long-term advancements in communication architecture and standards.

Additionally, the project investigated the benefits of one specific protocol, IEC 61850, to determine the feasibility and requirements for application in substations and feeders (including DERs). North American electric utilities are beginning to transition to using IEC 61850 within their substations. Widespread adoption of IEC 61850 has already occurred in some parts of the world. IEC 61850 is based on modern information technology concepts which can be used to structure data, standardize device models, increase peer-to-peer communication and reduce unnecessary wiring. A real-time model of a typical distribution substation with multiple feeders equipped with both conventional distribution system assets and DER was constructed using power hardware in the loop (PHIL)[3] to demonstrate specific uses cases in a controlled environment.

The project was implemented in two phases:

- Phase 1 - SDG&E Internal Project Work Prior to contractor procurement that includes
- Phase 2 – Architecture Baseline and Development
- Phase 3 – Pre-Commercial Demonstration of IEC 61850
- Phase 4 - SDG&E Internal Project Work prior to project conclusion

The Phase 1 activities included the following tasks:

- Task #1 - Development of Project Plan
- Task #2 - RFP Development
- Task #3 - RFP Release, Proposal Evaluation, and Vendor Selection
- Task #4 - Contracting, Procurement, Resourcing, and Kick-Off

The Phase 2 activities included the following tasks:

[3] Using a Real Time Digital Simulator (RTDS)

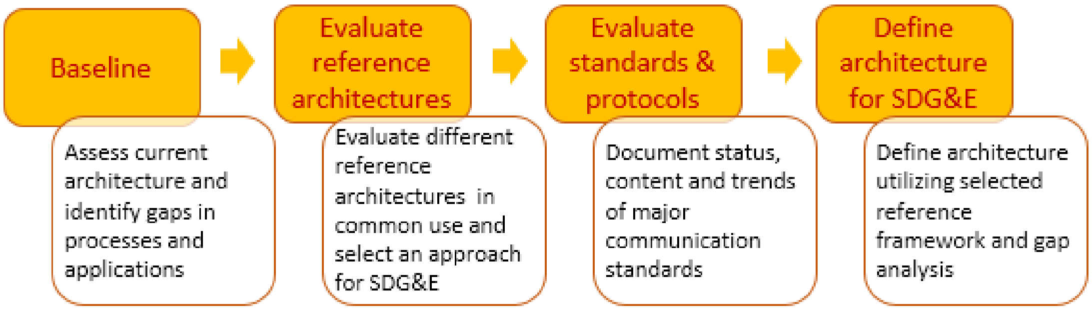

Figure 1-1. Phase 2 tasks.

Phase 2 – Task 1: Baseline

The goal of this task is to establish the as-is condition of the SDG&E system architecture. It assesses the building blocks of the current Distribution Operations architecture. The assessment also focus on identifying gaps in existing processes and applications.

Phase 2 – Task 2: Evaluate reference architectures

The focus of this task is to evaluate the different reference architectures in common-use in the industry and select the one most suitable for SDG&E to document the desired future state.

Phase 2 – Task 3: Evaluate standards and protocols

The goal of this task is to review the status, content, and trends of major utility communications standards (information models, protocols, and relevant cyber security standards), including ongoing relevant work at Standard Development Organizations (SDOs)

Phase 2 – Task 4: Define architecture for SDG&E

This task uses the results from the preceding tasks to define an architecture that utilizes the selected framework and findings from the standard and protocol research, to address the previously identified gaps in the as-is SDG&E architecture.

The purpose of Phase 3 of the project was to demonstrate real-world applications of the standards identified in Phase 2 and show how these can be used in the distribution system to addresses the information exchange needs between major system elements, especially with the increasing penetration of Distributed Energy Resources (DER).

The Phase 3 activities were divided into the following tasks:

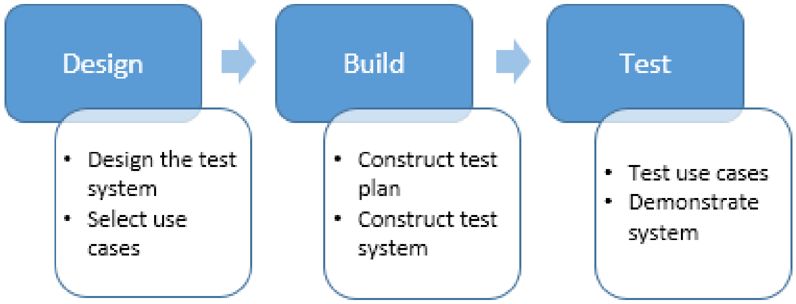

Figure 1-2. Phase 3 tasks.

Phase 3 – Task 5: Design

This task involved the design of a test system and selection of use cases capable of demonstrating the application of the standards identified in Phase 2 in as realistic a fashion as possible and to provide a platform to contrast the performance of the conventional approach to system control with that of an IEC 61850-based approach.

Phase 3 – Task 6: Build

This task involved the creation of a series of factory and site acceptance test procedures intended to test the execution of the use cases on the test platform, as well as the construction of the test system per the design generated in task 5.

Phase 3 – Task 7: Test

This task involved the execution of the use cases on the test system, and the capture of the results, that formed the basis for the findings, recommendations and next steps.

The Phase 4 activities included the following tasks:

- Task #1 – Comprehensive Final Report
- Task #2 – Technology Transfer

1.4 How to read this report

The table below provides a quick reference guide on the primary content areas of the report and the page number where each starts.

Table 1-1. Navigating the document

Item	Description	Starts on page
Baseline	**Phase 2 – Task 1: Baseline** Analyzes the SDG&E as-is condition by assessing the building blocks of the current Distribution Operations architecture and focuses on identifying gaps in existing processes and applications.	9

2 PROJECT APPROACH

2.1 Phase 1 – SDG&E Internal Project Work Prior to Contractor Procurement

Task 1 – Project Plan Development

Objective – Develop detailed work plan for the project.

Approach – The project team met with internal stakeholders to conduct a review of existing architecture and future plans to migrate to a more modern standards and protocols. Following activities were reviewed with the stakeholders:

- OpEx2020 vision and Vision 2030
- Relevant projects completed under GRC 2012
- Projects ongoing under EPIC-1 and EPIC-2
- Advanced Distribution Management System (Phase 2)
- Distributed Energy Resource Management System (DERMS) (relevant to the project area)
- Demand Response Management System (DRMS) (relevant to the project area)
- SCADA system
- Existing SDG&E architecture for electrical and communications infrastructure
- 61850 Substation Pilot
- Other relevant material, including but not limited to the IEC TC-57 architecture

The project team identified conceptual, functional and system requirements for the pre-commercial demonstration project. These requirements were identified by reviewing SDG&E's existing plans and high-level use cases to identify key systems and their interactions for key modes of operation. The project plan identified staffing requirements for the project, both internal and contracted, with definition of needed skills. Required equipment and other resources were also identified.

Output – Project work plan including technical scope definition, schedule, budget, and staffing requirements was developed.

Task 2 – RFP Development

Objective - Develop RFP for competitive procurement of contractor services for the requisite phases of the technical scope.

Approach – An RFP was developed for the contracted portion of the work, the contained the following sections:

- Brief Project Background
- Statement of Project Objective
- Scope of Work
- Approach
- List of Deliverables
- Expectations for Tech Transfer Plan
- Project Schedule
- Selection Criteria

- Solicitation Schedule
- Encouragement for Bids with DBE Participation

The RFP was sent to multiple recipients. The proposals expected from the respondents included (at a minimum):

- Meeting the requirements of the RFP (being responsive)
- Proposed technical approach for performing the work
- Concept of operations and system architecture
- System infrastructure specifications
- Test plan for testing at SDG&E facilities
- Measurement, verification and analysis of data
- Findings and recommendations, based on the results
- Tech transfer plan for use of project results
- Reporting to SDG&E
- Conformance with CPUC EPIC Decision 12-05-037 and other relevant EPIC decisions

The selection criteria (at a minimum) addressed the responsiveness of the bidder to the RFP requirements, elaboration on technical approach, cost, bidder experience and company qualifications, DBE participation, team structure, management plan, qualifications of individual team members, proposed schedule, cost, and acceptance of SDG&E Terms and Conditions. Bidders were encouraged to include DBE companies in their project team.

Output – RFP document was developed for release to recipients.

Task 3 – RFP Release, Proposal Evaluation, and Vendor Selection

Objective - Release RFP to external recipients, evaluate proposals received and shortlist prime contractor.

Approach – The project team worked with SDG&E supply management to release the RFP and manage the contractor selection. Obtained bidder responses from supply management and organized for stakeholders review during the evaluation process. Received proposal submittals were be validated, a proposal review team was established and a proposal review schedule was developed. Developed detailed evaluation criteria that evaluated the technical and financial response from the bidders. Scoring criteria incorporated an individual scoring sheet and a consolidated scoring workbook will be developed. Formed an internal proposal and project review panel of SDG&E subject matter experts from stakeholder groups to use the project results. Subsequent to developing the evaluation criteria, responses were sent to the review panel for review and scoring. Two review panel meetings were conducted to review the scores and discuss the proposals. During the evaluation process the scoring matrix was populated to get a clear picture of strength of the bidders' proposals. Proposals were reviewed along with the scoring approaches and scoring criteria. Follow up technical questions were developed for clarification from bidders. The proposals were evaluated to assess proposer's assumptions on SDG&E team activities and identify project risks. Evaluation workshops were conducted for bidders who meet the criteria to be vetted further, and necessary discussions on the technical aspects of the SOW and other terms and conditions were conducted that culminated in the selection of a vendor.

Output – Vendor selection including proposal evaluation matrix, scoring matrix and identification of the selected vendor.

Task 4 – Contracting and Procurement

Objective – Procurement of selected contractor services under contract with Supply Management.

Approach - Engaged with the selected contractor in contract discussions to finalize the scope of work, schedule and budget for the project deliverables. The following documents were developed and finalized as part of the contracts package:

- Detailed scope of work
- Detailed project schedule
- Detailed Project Budget
- Professional services agreement

Output – Prime contractor agreement was finalized with SDG&E supply management and the contractor.

2.2 Phase 2 – Task 1: Baseline

This task involved the analysis of the current SDG&E architecture. A methodology to document the findings was required and the CEN-CENELEC-ETSI[4] Smart Grid Coordination Group's Smart Grids Architecture Model (SGAM) framework was selected for this purpose. As will be described in greater detail in Task 2, SGAM was just one of several reference architectures evaluated for selection to document the desired end-state addressed in Task 4. SGAM was selected because there was an existing body of work available on the current SDG&E architecture that aligned with the SGAM approach. It did not however, preclude the possibility of the final architecture being defined in something other than SGAM.

2.2.1 Introduction to SGAM

A few words are required on the SGAM framework to contextualize the as-is architecture evaluation described in the rest of this section. The SGAM framework is a three dimensional model – two of which describe the so-called Smart Grid Plane.

The two dimensions of the Smart Grid Plane are Domains (covering the complete electrical energy conversion chain: Bulk Generation, Transmission, Distribution, DER and Customers Premises) and Zones (representing the hierarchical levels of power system management: Process, Field, Station, Operation, Enterprise and Market).

The various domain and zone elements are defined in the table that follow:

[4] In Europe the standards for safety and quality for product and service are developed and agreed by the three officially recognized European Standardization Organizations: the European Committee for Standardization (CEN), the European Committee for Electrotechnical Standardization (CENELEC) and the European Telecommunications Standards Institute (ETSI).

Table 2-1. SGAM Zones

Domain	Description
Bulk Generation	Representing generation of electrical energy in bulk quantities, such as by fossil, nuclear and hydro power plants, off-shore wind farms, large scale solar power plant (i.e., PV, CSP) – typically connected to the transmission system
Transmission	Representing the infrastructure and organization which transports electricity over long distances
Distribution	Representing the infrastructure and organization which distributes electricity to customers
DER	Representing distributed electrical resources directly connected to the public distribution grid, applying small-scale power generation technologies (typically in the range of 3 kW to 10,000 kW). These distributed electrical resources may be directly controlled by DSO
Customer Premises	Hosting both – end users of electricity, also producers of electricity. The premises include industrial, commercial and home facilities (e.g., chemical plants, airports, harbors, shopping centers, homes). Also generation in form of e.g., photovoltaic generation, electric vehicles storage, batteries, micro turbines… are hosted

Zone	Description
Process	Including the physical, chemical or spatial transformations of energy (electricity, solar, heat, water, wind …) and the physical equipment directly involved. (e.g., generators, transformers, circuit breakers, overhead lines, cables, electrical loads any kind of sensors and actuators which are part or directly connected to the process…).
Field	Including equipment to protect, control and monitor the process of the power system e.g., protection relays, bay controller, any kind of intelligent electronic devices which acquire and use process data from the power system.
Station	Representing the areal aggregation level for field level, e.g., for data concentration, functional aggregation, substation automation, local SCADA systems, plant supervision…
Operation	Hosting power system control operation in the respective domain, e.g., distribution management systems (DMS), energy management systems (EMS) in generation and transmission systems, microgrid management systems, virtual power plant management systems (aggregating several DER), electric vehicle (EV) fleet charging management systems.
Enterprise	Includes commercial and organizational processes, services and infrastructures for enterprises (utilities, service providers, energy traders…). e.g., asset management, logistics, work force management, staff training, customer relation management, billing and procurement…
Market	Reflecting the market operations possible along the energy conversion chain, e.g., energy trading, mass market, retail market.

The third dimension consist of five interoperability layers (Business, Function, Information, Communications and Component) that are overlaid on the Smart Grid plane following the same Domains and Zones.

The SGAM framework is established by merging the concept of the interoperability layers and smart grid plane. This merge results in the model which spans three dimensions:

- Interoperability (Layers)
- Domains
- Zones

The sub-sections that follow describe the SDG&E as-is state according to this model.

2.2.2 RACI analysis

The Business and Functional layers were developed by first identifying the key Distribution Operations functions, and the business units that have involvement in the functions, assessed through a RACI analysis (responsible, accountable, consulted and informed). The RACI view demonstrates the accountability and responsibility of physical business components, containing business services by business areas or other external organizational units.

- Responsible (R) stakeholders are those that undertake the exercise/action; i.e., do the work.
- Accountable (A) stakeholders are those that own the exercise/deliverable. Only one stakeholder should be accountable for an exercise/deliverable. They may own the budget (i.e., purse strings) and/or have overall management responsibility for the exercise/deliverable.
- Consulted (C) stakeholders are those from whom input is gathered in order to produce the deliverable. They tend to be subject matter experts in specific business areas or technologies.
- Informed (I) stakeholders are those to whom the deliverable is distributed as they tend to have a dependency on its content.

As expected most of the accountability/responsibility falls within the electric operations business area, more specifically Electric Distribution Operations control.

The RACI matrix also showed two areas of concern of stakeholders with regards to the business architecture:

1. Functions where responsibility may fall in multiple business units (siloed operations), and
2. Functions that may need to be further defined to support future operations, mainly market services.

There are several business functions that have multiple business units either responsible, accountable, or both. This is subject to further review to determine if a proper segregation of duties exist for those business functions. Specific observations made include:

- Multiple A, R, or A/R assignments made for a function but appears to be justified based on apparent division of duties depending on circumstances
- More than 1 to 2 A, R, or A/R assignments that may warrant further investigation of flow of responsibility/accountability
- Multiple organizations are A, R, or A/R and perform the same functions—Possible siloed operations that might be made more efficient through standardized or common platforms

2.2.3 Business layer

The SDG&E business layer has been defined in terms of business units and their interdependencies to support the core distribution operation functions. These functions in turn support SDG&E core mission business objectives of providing safe, reliable electric service to customers. The SGAM business layer was constructed, identifying which domain and zone each business unit appears to influence, based on the accountability (A) or responsibility (R) assignment made in the RACI matrix.

Figure 2-1 summarizes the major Business Units that are identified based on SDG&E organization to be involved in supporting the SGAM functional layer.

The main business areas are:

- Planning and policy (asset management)
- Electric operation, that by itself has two sub areas of engineering and operation. Operation also splits between grid operation (transmission grid - EGO) and distribution operation (EDO).
- Information technology and operation technology, and
- Customer services.

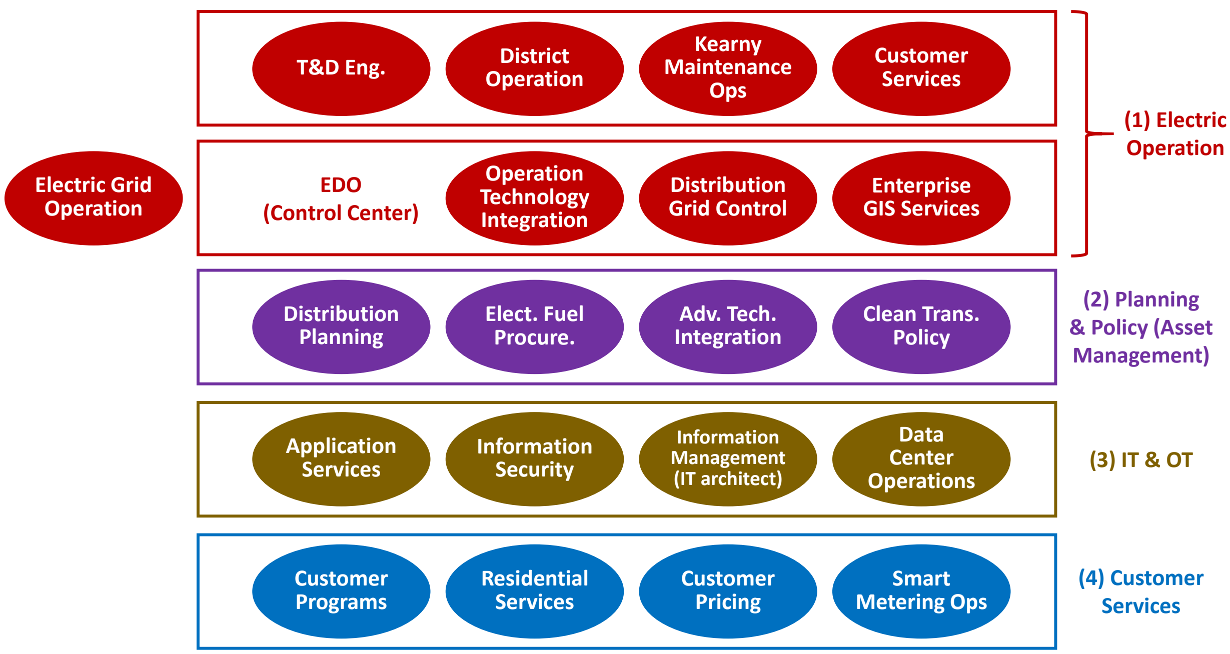

Figure 2-1. Business Units that participate in Distribution Operations functions

As identified in the SGAM analysis, different functional groups were identified in different zones that appear to be common across the domains of interest for Distribution Operations.

Table 2-2. As-is state of the SDG&E business layer

Zones	As-is state
Enterprise	**SDG&E Weather**: Weather and solar potential forecasts are generated daily and distributed across multiple organizations.

Zones	As-is state
	IT&OT: Information and Operation Technology supports all operational units through the establishment and maintenance of common infrastructures, communications networks, applications, data centers, and databases. Data management, archiving and retrieval is necessary across a common function to gather and process data from all domains and zones in order to provide the total picture of system status. As shown at the Functional layer, independent organizations also provide some level of data management, archiving, retrieval, and disposal for their own purposes.
Operation	**DER**: DER monitoring & control functions are shared among the DER group in Electric Operations organization, and the Electric and Fuel procurement group in the Asset Management organization. The SCADA group also gets involved with DER management since any DER control must first be coordinated and approved with SCADA operations. Thus several business units may become involved in a DER operation. The DER group in Electric Operations also becomes involved in microgrid islanding operations as well. **Emergency Operations (management)**: This group provides information on storm crew and fire operations, to support of Electric Systems operations. Thus the group serves cross-cutting functions across all the domains in Electric Operations. This group has full responsibility for these functions, and informs any group who needs to be aware of that information, depending on the circumstances.
Domains	**As-is state**
Transmission	The transmission domain is included in the architecture since it is part of Electric Operations business unit, which encompasses both the EDO and Electric Grid Operations (EGO). EGO works with EDO to coordinate load management and share other information that may affect overall system reliability. EDO works to coordinate management of large scale storage as it related to Grid Operations.
Distribution DER	EDO in the Electric operations business unit has multiple responsibilities and accountabilities in both Domains as described earlier. However, EDO and DER groups are separate entities, connected only at the top Electric Operation level.
Customer	Similar to the component, communications, information, and functional layers, the Customer business layer is "self-contained" in the customer business domain, with accountability extending into the Enterprise layer. The CSF and Smart meter operations group of Customer services is accountable for the Customer (end user) monitoring, but the Customer engagement group within the IT&OT Business Unit also shares responsibility for monitoring, and engaging DRMS.

2.2.4 Functional layer

Figure 2-2 summarizes the major functional groups in which the majority of the Distribution Operations functions in the RACI analysis can be categorized.

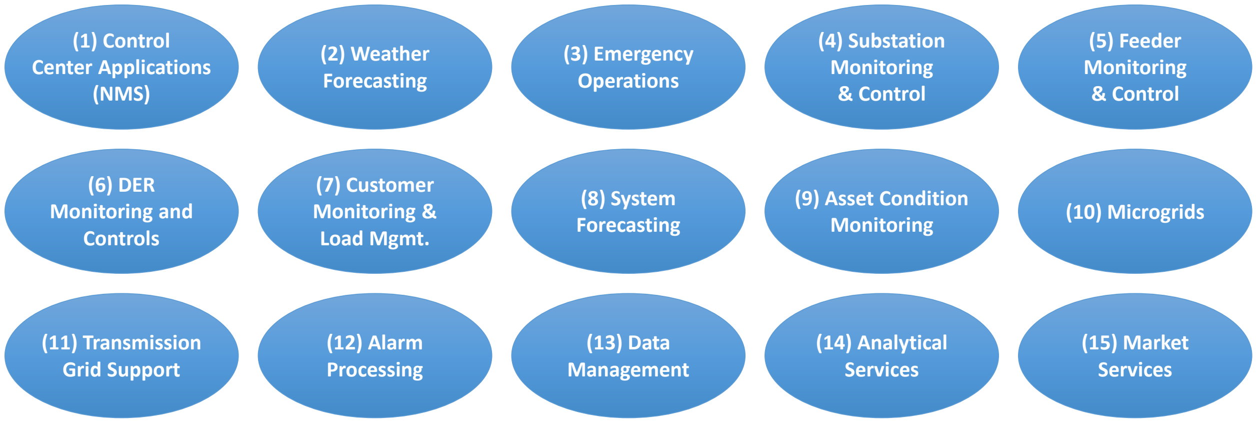

Figure 2-2. Distribution Operations major functional groups

Table 2-3. As-is state of the SDG&E functional layer

Domains	As-is state
Distribution	Most of the functions noted in the RACI analysis fall in the distribution domain, since these functions are the primary responsibility of the EDO. Operation of these distribution functions are interdependent with the DER and Customer functions, since overall system operation and function is affected by the operation of each of these individual domains.
DER	DER functions include the requirements to support distributed generation and storage functions, as described in the component layer. Responsibility for the individual functions lies across several business units as depicted in the RACI analysis.
Customer	Direct customer-facing functions are self-contained within the Customer Services business unit. The Meter Data Management (MDM) and Load Management functions provides data that can be shared and utilized across the other domains.

2.2.5 Information layer

For Enterprise, Data clients/interface points are via an Enterprise Service Bus (ESB). MultiSpeak also exists at the Enterprise layer for communications between the Network Management System (NMS) and the operations zones, and with field DER devices.

Below the Enterprise level, there appears to be an absence of a well-defined information layer. The purpose of an information layer is to describe the information that is being used and exchanged between functions, services, and components. It contains information objects and the underlying canonical data models. These information objects and canonical data models represent the common semantics for functions and services in order to allow an interoperable information exchange via the communications layer.

Within SDG&E there appears to be a variety of means for information exchange via vendor proprietary protocols, specific to a given application or use case, resulting in systems and applications being operated separately. The as-is situation is summarized in Figure 2-3. (NOTE: “Proprietary” in Figure 2-3 refers to “vendor proprietary protocols”.)

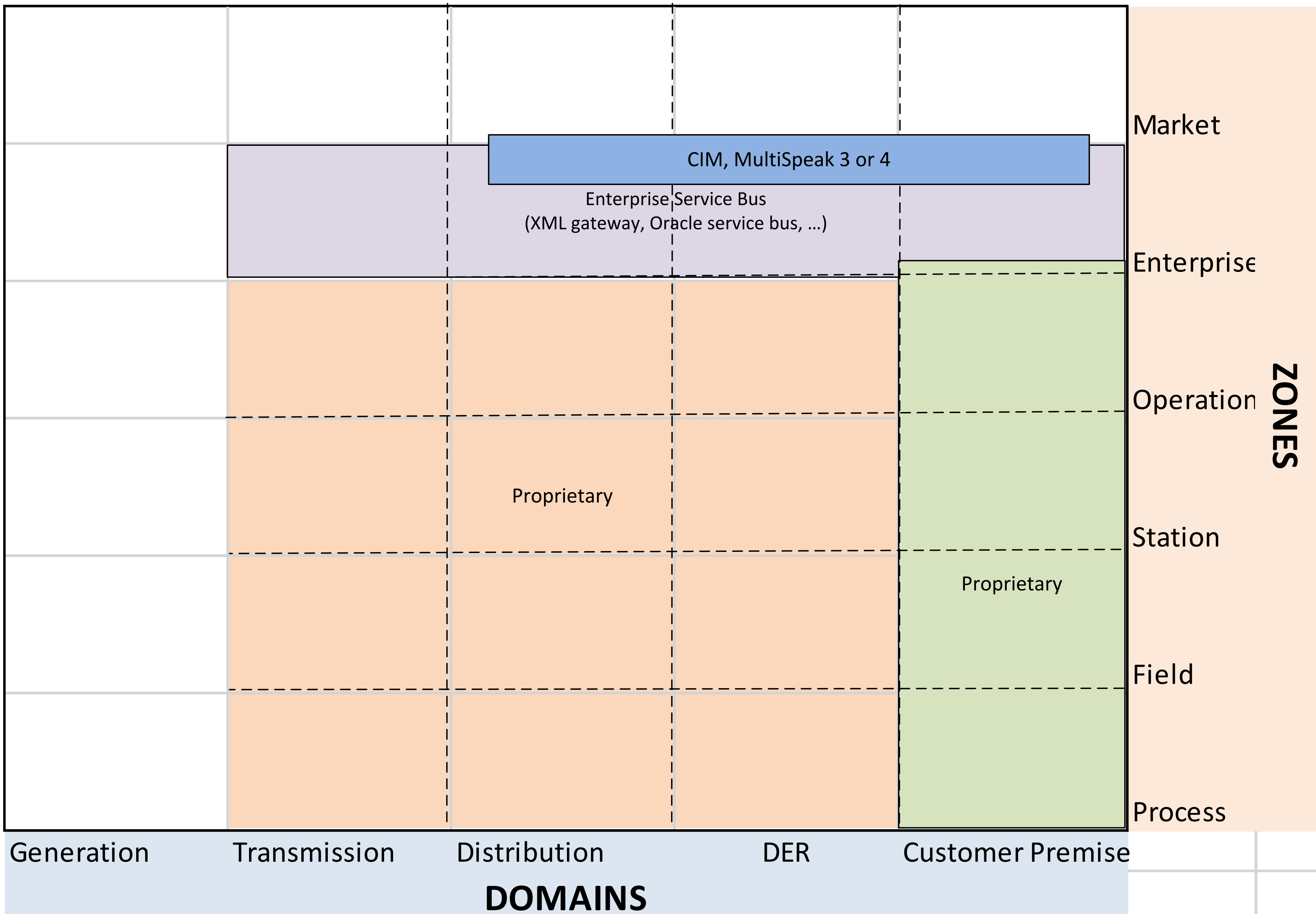

Figure 2-3. SDG&E as-is information layer

2.2.6 Communications layer

The communications layer can be defined as having two parts:

1. The communications applications protocol layer: Communications protocols related to applications such as DNP3, MODBUS, ICCP, etc. that define not only how the protocols interface with the transport protocol layers, but also describe data formats, objects, logical connectivity, etc. that support the given application.
2. The communications transport protocol layer: OSI layer 4 and below, which comprises the transport (layer 4), network (layer 3), data link (layer 2), and physical (layer 1).

2.2.6.1 Communications applications protocol layer

For Enterprise, Data clients/interface points are via an Enterprise Service Bus (ESB). MultiSpeak also exists at the Enterprise layer for direct communications with field DER devices; it is transparent to the zones in between.

At the market layer, a specific protocol is absent to support distribution operations. ICCP exists in the transmission domain, which has become the standard in the transmission domain to support communications between control centers of external entities and SDG&E, including CAISO.

In the Station and Field zones across the distribution and DER domains there exists a variety of communications applications protocols including DNP3, C37.118, IEC 61850, as well as legacy protocols SCOM, and MODBUS. The customer premise domain from process to Enterprise is connected via a specific vendor field area network platform. This is summarized in Figure 2-4 below.

2.2.6.2 Communications transport layer

In the Operation and Enterprise zones, TCP/IP is the prevalent communications wide area networks between sites, and Ethernet based local area networks within a site. IP version 4 is in operation. SDG&E Plans to migrate to IP version 6 is unknown at this time. For the market zones, the use of serial communications appears to be prevalent.

For distribution and DER at the station, field, and process zones, legacy serial connections exist, as well as some IP based communications. Point-to-point radios such as low capacity microwave radio, or point-to-multipoint low speed MAS radios also exist at these levels, primarily not for direct customer interfaces. The RF mesh network associated with the vendor-specific field area network has been established to connectivity with customer applications.

An array of communication media are used to connect the SCADA server to the various devices; microwave, fiber, leased lines, cellular lines (Verizon) and radios (4F and Tropos), among others. Only a fraction of the links are capable of high-speed communication – typically those to the newer generation SI/SA equipped substations – which allows the use of DNP over TCP. DNP serial and SCOM, a legacy serial protocol, are in use to the balance of the SCADA devices. Some substations are equipped with condition based monitoring equipment, and a separate communication path, normally utilizing Modbus, is used to interface with these devices.

Figure 2-5 below maps the current status of the SDG&E communications transport layer to the SGAM Smart Grid plane.

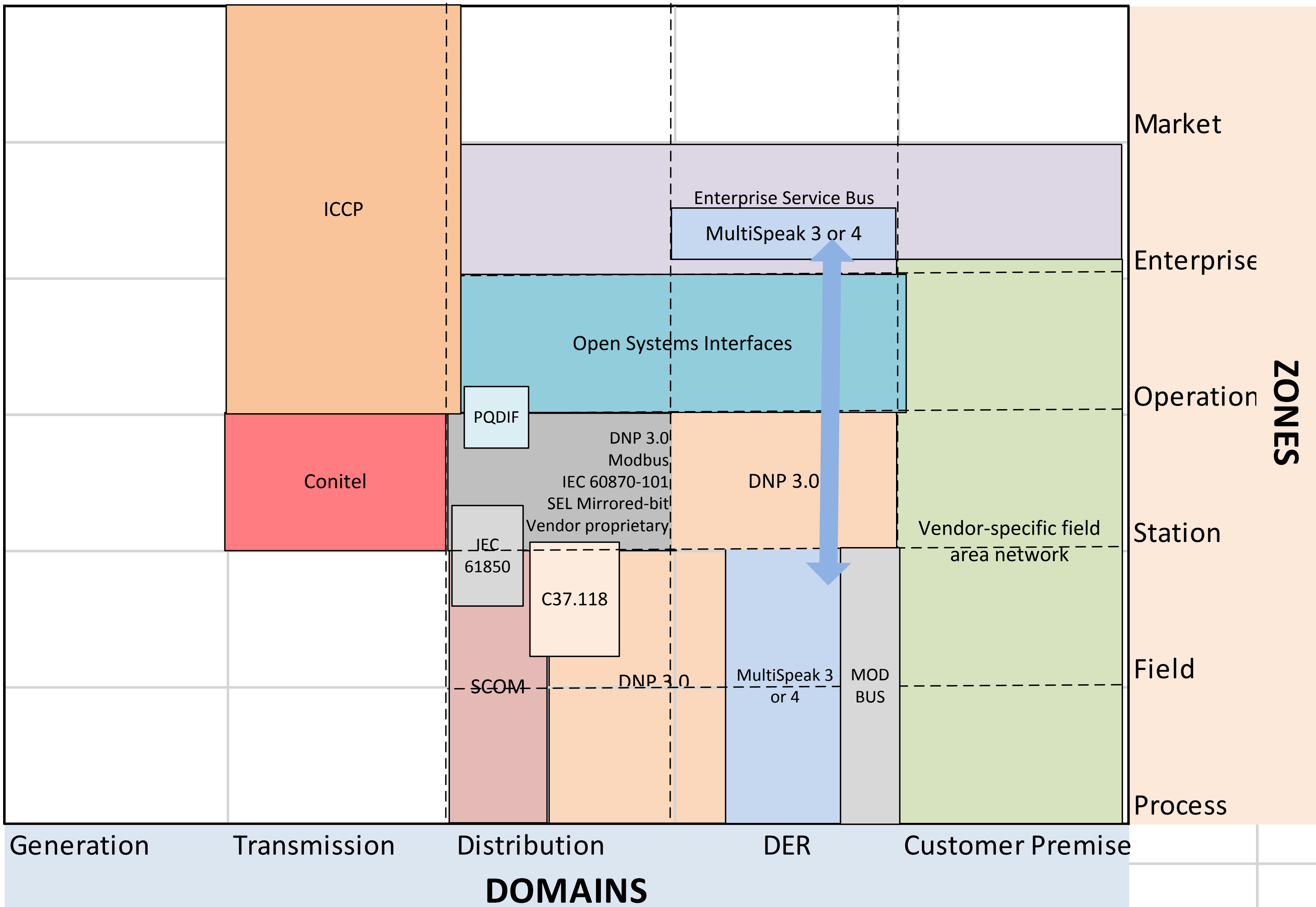

Figure 2-4. SDG&E as-is communications application layer

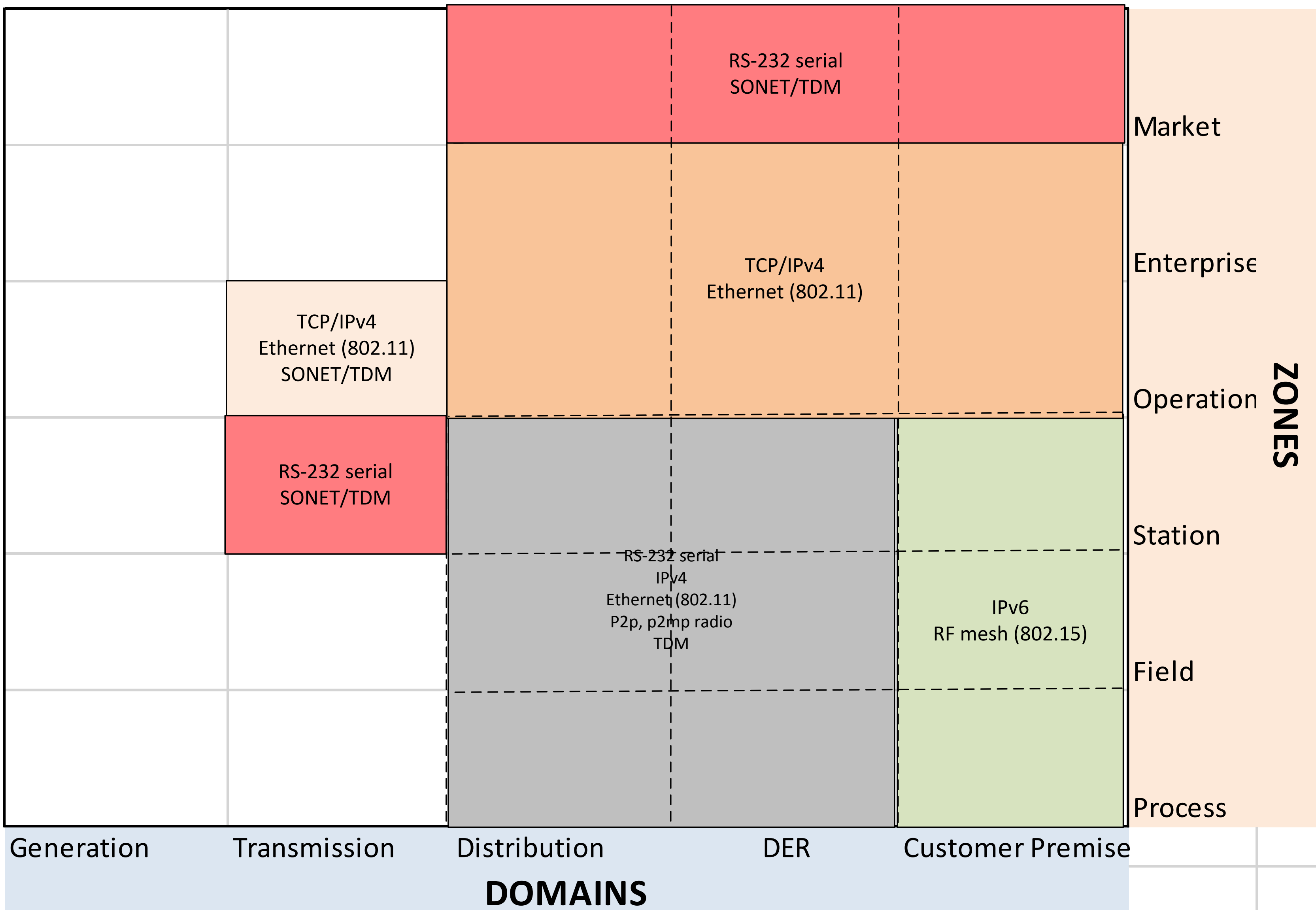

Figure 2-5. SDG&E as-is communications transport layer

2.2.7 Component layer

Electric Distribution Operations (EDO) maintains the current distribution SCADA system and Network Management System (NMS). The primary elements of the system are in the Distribution domain that includes a centralized SCADA server at the operations level that communicates downstream with substation and field devices, and upstream with the NMS, the PI data repository and other clients.

The SCADA server is currently communicating with three different categories of devices:

- *Substation Level*: Legacy SCADA Remote Terminal Unit (RTU) based systems
- *Substation Level*: Substation integration/automation (SI/SA) based systems that utilize data concentrator/substation controller devices (Real-Time Automation Controllers, or RTACs) to integrate data from various microprocessor based Intelligent Electronic Devices (IEDs). Most of these IEDs are inside the substation but there are a few pilot projects in progress where downstream feeder IEDs are integrated back into the substation via a separate RTAC and communications network. Both the feeder and substation RTACs share a secure gateway to the SCADA server.
- *Field level*: There is a subset of feeder devices that are SCADA enabled and under SCADA control, such as SCADA switches, SCADA capacitors, SCADA reclosers, etc. Some circuits also include sensors for faulted circuit indication (FCI) that are communicating through SCADA.

A DER Management System (DERMS) is currently located in the station level and is communicating with a Control Area Manager (CAM). This is a vendor-specific control platform that performs data aggregation and control of groups of assets.[5] The CAM would normally communicate directly with the DER assets but to ensure coordination with, and adherence to, standard operating procedures for the protection and control of distribution assets, all controls are channeled via a Substation Modernization Platform (SMP)[6] gateway device that provides a SCADA-controlled permissive to allow, or block, DERMS controls. A DERMS client is also located at the Enterprise level for monitoring.

Metering data is extracted from meters via a Meter Data Management System (MDMS) and usage data is fed into data warehouse. There is a separate Demand Response Management System (DRMS) that utilizes the vendor specific field area network communication platform. The MDMS and DRMS currently have no touchpoints to SCADA, at any of the levels, and are utilizing a completely separate infrastructure.

2.2.8 Security architecture

Security services support cross domain foundational services, and is discussed in this baseline review at a high-level. The SDG&E security architecture is subject to review of details of what is deemed as confidential and can be disclosed. Key characteristics of the SDG&E security architecture include:

- Data Acquisition Security: SCOM protocol has no security features. DNP3 serial/IP features used
- Security network architecture: shared with Enterprise Information Security
- SCADA Access Security:

[5] A detailed description of the platform and its architecture are considered outside the charter of this document.

[6] Product name for a substation hardened, data concentrator manufactured by Cooper

- User login: Requires separate log-ons by system. Two factor authentication not available (i.e., No smart cards, tokens, dongles or biometric systems in use).
- Remote Operating Access: via VPN and IT security infrastructure but with limited functionality and profile diversity.
- Access Security management: Using simple user account management

The Distribution Operations security architecture is compliant with SDG&E security policies. SDG&E security policies take into account applicable NERC CIP requirements, as well as NISTIR 7628 guidelines.

2.2.9 Conclusions regarding SDG&E's current situation

After meeting with a comprehensive list of internal stakeholders representing Reliability, DER, ADMS, Distribution Planning, EDO, IT, SPACE and Customer Generation, a composite picture of the current and planned control architecture was created. Some of the architectural challenges observed are summarized below:

- **Parallel communication paths**. In some instances there are multiple communication paths from control center entities to the same physical location stemming from restrictions of the existing communication infrastructure, and desire to separate daily operations from experimental and pilot technologies.
- **Time domain separation**. There are functions that require a certain speed of response that are being performed at locations in the architecture that make it challenging to obtain deterministic levels of performance.
- **Centralized decision making**. The architecture is highly centralized, which places restrictions on the speed of response and limits the ability to perform distributed autonomous actions.
- **Communications infrastructure**. The absence of a high speed communication backbone to substation and field devices places restrictions on the type of devices and data that can be integrated into the system.
- **Duplication of functions**. The planned architecture contains some duplication of functions, like Volt/var control for example, with multiple entities identified as being responsible for this application. This may be just a matter of finalizing the correct "owner" for the application, but having the same or similar application in multiple locations is problematic.
- **Roles and responsibilities**. The current architectural depiction developed in the Distributed Control center project did not previously map functions to stakeholders and responsible parties. The RACI analysis for this Smart Grid Architecture Demonstration Project has now established a map of existing roles and responsibilities.
- **DER integration**. DER devices are integrated into the architecture but more as one-offs or pilots than a large scale deployment.
- **Scalability**. There is a concern whether the architecture as currently envisaged can scale adequately, both in terms of increased DER penetration as well as the ability to manage more autonomous functions given the highly centralized nature of the design.

Potential gaps or issues in relation to the SGAM architecture is summarized in Table 2-4.

Table 2-4. Summary of key gaps in the context of SGAM architecture

Ref ID.	Baseline Architecture Issue	Impact
SGAM Component Layer		
C1	SCADA controls are centralized at the control center: As the capabilities of the communications infrastructure advances, additional intelligence will need to be deployed closer to the customer premise, allowing pro-active decisions to be made locally to avoid or minimize outages, while informing the utility systems and operators of the local actions taken. Migration to this architecture will impact all SGAM layers, including present business processes Control of DER assets is not coordinated via SCADA. Direct control is accomplished via vendor proprietary dedicated links. However, the DER asset owners must coordinate with Distribution Operations SCADA prior to implementing any controls	High
C2	The Customer domain appears to be independently operated with no interoperability with other domains. Any data exchange occurs at the Enterprise level, when may impede the implementation of timely actions to improve service.	Med
SGAM Communications Transport Layer		
CT1	Only a fraction of links are capable of high-speed communications (typically those to the newer generation SA/SA equipped substations	Med
SGAM Communications Applications Layer		
CA1	Specific protocol to support distribution operations at market level is absent. Not currently a widely utilized application. However, as utilities migrate to a distribution systems operator (DSO) role, communications among market entities (third party service providers, DER aggregators, CAISO, other utilities) will be important.	Med
CA2	Some legacy protocols still in use such as SCOM, MODBUS; there is a variety of legacy protocols from the process to the Operations levels across all domains. Each protocol requires a certain amount of maintenance and upkeep. There is no clear path of interoperability between the protocols, without having to go to the Enterprise zone to allow a common interface between systems. The component layer confirms that there are no direct connections from the Customer domain to allow interoperable processes to occur	Med
SGAM Information Layer		
I1	In the SGAM context, this layer is virtually non-existent in the SDG&E environment, from the operations layer to the process layer, across all domains. Proprietary methods of defining data information requirements exist with "siloed" applications, and no set of standards. Most of the information formats are defaulted to the communications applications protocols. This is a key gap; to support the multiple proprietary methods results in an increased cost of operations.	High

Ref ID.	Baseline Architecture Issue	Impact
SGAM Functional/Business Layers		
F1	There are independent functions at the market level, for specific needs in Customer programs and Electric & Fuel procurement. There appears to be gaps in this area to support future Distribution operations requirements	Med
F2	Certain functions appear to have multiple business units who are assigned responsibility or accountability, such as: • Storm and fire operations • Feeder Control • Asset condition based monitoring • Load management (emergency) • Substation monitoring, control Some of these multiple assignments can be attributed to the varying requirements of the functions: based on certain operating conditions: at times a certain group may be responsible for the function until a normal operational state is returned; under other conditions, another group may have the responsibility.	Low
F3	Functions of alarm processing, data management, and analytical services appear to be performed independently by the groups in relation to the alarms, data, and analytics for which the group has responsibility or most interest in. Thus these functions may be replicated across several organizations.	High
F4	Reconciliation of proposed use cases with functional and business processes. For Phase 3 testing, a certain number of use cases are identified for testing at the ITF. These use cases should also be reviewed to determine their impact on existing functions, groups, and RACI assignments for Distribution Operations, to identify any changes that may be required from existing processes	High
SGAM Business Layer		
B1	The Distribution, DER, and Customer domains appear to be independently managed with few cross-domain services. This may impede efficiency of operations	Med

2.3 Phase 2 – Task 2: Evaluate reference architectures

This Task provides a summary review of reference architectures including:

- SGAM architecture
- IEC TC-57 reference architecture
- Gridwise Architecture
- EPRI Intelligrid architecture
- Others, including DOE Grid architecture initiative

The objective is to propose a comprehensive architectural framework that would help SDG&E properly capture various aspects of the grid modernization. The key considerations in the selection of the reference architecture are [5]:

- Grid architecture is not just an electric circuit; it is a network of structures that are coupled together within certain constraints. Changes to the grid impact all the set of structures, not just siloed domains.
- Grid architecture is evolving, and needs to accommodate existing legacy systems while drawing plans for future architecture versions.
- Grid architecture involves multiple tiers, and are more that enterprise wide IT systems. Various structures are involved in control, communications, measurement and sensing, data management, and computational capabilities within utility system elements, and non-utility system elements.
- Grid control and coordination may include local optimization and system wide coordination.

The following items can be considered as the motivations for the development and utilization of a reference architecture:

- To obtain a comprehensive plan for the development of future system and components;
- To provide the possibility of identifying the gaps in the "as-is" system
- To provide a proper methodology for addressing standardization gaps
- To identify the required harmonization between standards and suggest possible approaches for this purpose.

2.3.1 Smart Grids Architecture Model (SGAM)

The CEN-CENELEC-ETSI Smart Grid Coordination Group's Smart Grids Architecture Model (SGAM) Framework [1] aims at offering a support for the design of smart grids use cases with an architectural approach allowing for a representation of interoperability viewpoints in a technology neutral manner, both for current implementation of the electrical grid and future implementations of the smart grid.

Since the model was discussed in some depth in the preceding section, it will not be re-examined again.

2.3.2 IEC TC-57 reference architecture

The TC57 reference architecture, developed through the IEC efforts, helps visualize the existing object models, services, and protocols that are applied in the management of power system and how they relate to each other, and can provide a guide to SDG&E in the formulation of a target reference architecture. The TC57 reference architecture incorporates the key standards that are also included in the NIST reference [2], although not all the TC57 standards are currently in the NIST Catalog of Standards.

The TC57 reference architecture also provides a “layered” approach starting with a top layer concerned with integration of systems/applications via inter-application messaging as provided via commercial off-the-shelf middleware. Below the top layer are the next two layers considered for data representation (as specified in the Common Information Model (CIM) and Generic Interface Description (GID) interfaces, respectively), as specified in the interface standards of 61970 and 61968. Below these layers represents the various transmission and distribution computer systems/applications for which integration standards are being developed in TC57. The protocols and standards included in the TC57 reference architecture can be harmonized with several layers in the SGAM architecture, especially at the Information and Communications layers.

2.3.2.1 TC57 future trends

Based on the existing TC57 reference architecture, several future trends are identified and discussed in TC57 reference architecture document [3]:

1. Develop a strategy to combine and harmonize the work of these various activities to help facilitate a single, comprehensive plan for deployment of these standards in product development and system implementations. The following are suggested as starting points:
   - Use of Common Object Modeling Language and Rules
   - Harmonization at Model Boundaries
   - Resolution of Model Differences
   - Basis of a Future Vision for TC57
   - Process of Starting New Work in TC57
2. Now that the TC57 standards, such as the 61968/61970 CIM and 61850 standards, have been recognized as pillars for realization of the Smart Grid objectives of interoperability and device management, it is imperative that a correct understanding of these standards and their application be made available to the key stakeholders and all other interested parties involved in implementing the Smart Grid.
3. The future reference architecture for power system information exchange is intended to provide a roadmap for future work in standards development within TC57 that takes into consideration new utility industry needs, directions in new available technology to address these needs, and other relevant activities of a broader nature. It also seeks to establish a strategy for addressing these needs, such as IntelliGrid, the GridWise Architecture Council, etc.

2.3.3 Gridwise framework

The GridWise Architecture Council (GWAC) [4] has turned to the question of how to take advantage of the increased availability of two-way communications and intelligent, communicating devices and sensors within the electric power infrastructure and end-use sites of electric power. The topic of transactive energy (TE) as a means to effectively manage and control an increasingly complex electric power infrastructure has emerged as a focal topic in GWAC’s work to build on previous interoperability work.

The GWAC defines transactive energy as follows:

The term "transactive energy" is used here to refer to techniques for managing the generation, consumption or flow of electric power within an electric power system through the use of economic or market-based constructs while considering grid reliability constraints. The term "transactive" comes from considering that decisions are made based on a value. These decisions may be analogous to or literally economic transactions.

The elements of TE are the components of a transactive architecture that need to be addressed in the design of a system. They provide a starting point for discussion by presenting the basic structure for an approach to transactive architecture design.

GWAC provides some guidance on the creation of a conceptual architecture for transactive energy. Please note that GWAC does not provide such an architecture; that is, the work to be done by a core team of experienced system architects that and would represent the design of a specific example of a TE system. Rather, GWAC suggests key elements and principles to be considered in the development of the Transactive Energy Conceptual Architecture. To that end, the following principles are listed as starting points for the architectural foundation:

1. Strong consideration should be given to the inherent structure of the energy systems under consideration; the hierarchical structure of large-scale power delivery systems from the Balancing Authority to distribution grid endpoint on one hand, and the smaller scale less hierarchical structure of micro-grids on the other. Likewise, the existing control structure for involved energy systems should be considered when developing the structure of the TE architecture.
2. Self-similarity or an approximation may be evident in the relevant structures and should be considered as a means of obtaining scalability and organizational regularity (as a means of dealing with complexity), but recognize that differing goals may apply at different levels in the recursion.
3. Layering for optimization decomposition may be considered as a mathematical foundation for structure of the control and coordination portions of the architecture.
4. The architecture should be agnostic to the general physical layer (refer to the Control Abstraction Model): specific sensors and controls, energy types, etc., should not be specified nor eliminated by the architecture.
5. The ability of the TE system to operate should not be limited to any specific type of communications network or specific technology; e.g., it must not be limited to broadband Internet communications only.
6. The architecture should accommodate open international standards, and must not restrict implementations to proprietary interfaces, algorithms, communication protocols, or application message formats.
7. To the extent possible, the architecture should be adaptable to changes in underlying energy systems, in terms of structure, capabilities, business models, and innovation in value creation and realization.
8. The architecture should include plans for convergence of network types over time: physical networks (energy system infrastructures), information and communication networks, financial networks, and social networks.

As mentioned in this section, GWAC does not provide a reference architecture. Therefore, it is not possible to present a use case for GWAC.

2.3.4 EPRI Intelligrid

The Integrated Energy and Communications Systems Architecture (IECSA or IntelliGrid architecture [5]) project initiated by EPRI represents the initial steps on a journey toward a more capable, secure, and manageable energy provisioning and delivery system. The IntelliGrid architecture project envisions a variety of plausible futures for electric and energy service operations ranging from advanced automation to dynamic consumer response. The project results propose the next steps in the process of bringing this vision to fruition. These steps include using more rigorous systems engineering practices, application of IntelliGrid architecture principles, and implementing the project recommendations.

The IntelliGrid Reference Architecture is based on an Architecture Framework bounded by the information infrastructure requirements of the power system industry. The framework includes the business needs of the power system industry, the strategic vision based on high level concepts of distributed information, the tactical approaches based on technology independent techniques, the standards, technologies, and best practices that could be used in the power industry, and a methodology for project engineers to use to create a coherent system out of the individual pieces. The reference architecture is based on an Architecture Framework bounded by the information infrastructure requirements of the power system industry. The framework includes:

- **Business Needs** of the power system industry, as captured in the power system operations functions, and categorized into the **IECSA Environments**
- **Strategic Vision** based on **High Level Concepts** of distributed information
- **Tactical Approach** based on **Technology Independent Techniques** of common services, information models, and interfaces.
- **Standard Technologies** and **Best Practices** that could be used in the power industry
- **Methodology** for automation architects, power system planners, project engineers, information specialists, and other IntelliGrid users to zone in on the exact parts of the IntelliGrid Architecture that is directly relevant to them, and to quickly access the IntelliGrid recommendations.

The IntelliGrid Reference Architecture framework generalizes and extracts the architecturally significant requirements by cross-cutting energy industry requirements involving distributed information, and provides a technology-independent architecture for project engineers to use as they determine solutions for specific implementations.

2.3.5 Others

In the previous sections, the most widely accepted reference architectures are discussed. However, there are many other reference architectures that are not discussed in detail in this report; they are variations from the widely accepted reference architectures. This section briefly introduces these reference architectures:

2.3.5.1 PNNL Grid Architecture/DOE Grid Architecture Initiative

This reference architecture is prepared for the US Department of Energy (DOE) by Pacific Northwest National Laboratory (PNNL) [6]. It provides selected views into a possible future where the utility power system(especially at the distribution level) becomes a platform for energy innovation, with coordination (not centralized command and control) of many types of resources, allowing multiple control and market mechanisms and approaches to coexist on and connect to the utility power system simultaneously without compromising electric reliability.

2.3.5.2 Smart Grid Reference Architecture

Smart Grid Reference Architecture (SGRA) [7] is collaboratively developed by SCE, IBM, and Cisco. This reference architecture is designed to address the challenges, concerns and questions facing smart grid architects implementing smart grid solutions for their utility. As with any reference architecture, it aims to provide a foundation for utilities in the development of their smart grid architectures and to serve as a guide for implementing specific new features.

2.3.5.3 P2030

This is a standard prepared by IEEE [8]. It provides guidelines in understanding and defining smart grid interoperability of the electric power system with end-use applications and loads. Integration of energy technology and information and communications technology is necessary to achieve seamless operation for electric generation, delivery, and end-use benefits to permit two-way power flow with communication and control. Interconnection and intra-facing frameworks and strategies with design definitions are addressed in this standard, providing guidance in expanding the current knowledge base. This expanded knowledge base is needed as a key element in grid architectural designs and operation to promote a more reliable and flexible electric power system.

2.3.5.4 Smart Grid Conceptual Model

Smart Grid Conceptual Model [9] is a document prepared by NIST/SGIP which provides a tool for discussing the structure and operation of the power system. It defines a set of domains, actors, applications, associations and interfaces that can be used in the process of defining smart grid information architectures. It includes diagrams that can be used for visualizing the use cases and components of the smart grid and its implementation.

2.3.5.5 Smart Energy Reference Architecture

Microsoft has developed a reference architecture based on familiar, cost-effective Microsoft platforms that can serve as the basis for development of the "integrated utility of the future." The Microsoft Smart Energy Reference Architecture (SERA) is Microsoft's first comprehensive reference architecture that addresses technology integration throughout the full scope of the smart energy ecosystem. SERA has been endorsed by a number of global solutions providers whose energy industry solutions span the entire energy ecosystem — from the power grid to the home. SERA helps utilities by providing a method of testing the alignment of information technology with their business processes to create an integrated utility.

2.3.6 Recommended architecture framework for SDG&E

Taking into account each architecture attributes to meet intended purposes, one architecture, SGAM, has been developed relatively recently (2012), building on existing architectures such as the NIST Conceptual Model (NIST 2009), the GridWise Architecture Framework (GWAC 2008), as well as architecture standards like The Open Group Architecture Framework (TOGAF).[7] The SGAM model can describe an architecture through interoperability layers that relate potential use cases and functions and their effect on business requirements and processes. The SGAM model attributes can relate to the elements presented in the discussion above.

[7] TOGAF was developed by The Open Group starting 1995, with several revisions since then

The relatively recent NIST Special Publication 1108r3 (September 2014), advocates the SGAM reference architecture as “a template for architects to follow while building aspects of a smart grid architecture, regardless of an architect’s specialty (such as areas of transmission, distribution, IT, back office, communications, asset management, and grid planning.” The SGAM utilizes an enterprise-wide, service-oriented approach to describe a smart grid architecture. The architectural framework provided by SGAM can be used as a guide to connect business objective and processes to the functional and system requirements needed to support the business objectives:

- To provide stakeholders a common understanding of the elements that make up the smart grid and their relationships
- To provide key stakeholder communities traceability between the functions and the goals of the smart grid
- To provide a series of high-level and strategic views of the envisioned business and technical services, supporting systems, and procedures
- To provide a technical pathway to the integration of systems across domains, companies, and businesses
- To guide the various implementation architectures, systems, organizational structures and supporting standards that make up the smart grid

The SGAM is an evolving framework, and NIST is working through the SGIP’s Smart Grid Architecture Committee (SGAC) to align this effort with the European Union Smart Grid- Coordination Group (SG-CG), the International Electrotechnical Commission (IEC) TC57 WG19 (IEC 62357), and IEC TC8 WG5 and 6 (Use cases).

2.3.6.1 SGAM architecture framework for SDG&E

The SGAM model is the best fit for SDG&E because of its capability to relate the technical layers with business goals, as well as define use cases in relation to their impact on all key layers.

To confirm selection of the recommended reference architecture for SDG&E, meetings and discussions were held with the representatives of SDG&E. Based on these discussions, SGAM was selected for the representation of the SDG&E reference architecture. The main reasons for choosing SGAM were as follows:

- SGAM reuses the existing models (e.g., NIST) and architectural frameworks (GWAC)
- Coherence of SGAM with respect to the overall smart grid standardization process from Smart Grid Coordination group (SGCG)
- SGAM is the most comprehensive reference architecture for use case development because of incorporating business, function, information, communication, and component layers.
- It is possible to map the TC57 in the communication and information layers of SGAM.

2.4 Phase 2 – Task 3: Evaluate standards and protocols

The goal of this task was to review the status, content, and trends of major utility communications standards (information models, protocols, and relevant cyber security standards), including, but not limited to IEC 61850 (for substation, feeder and DER), IEC 61968/61970 CIM, IEEE 1815 (DNP3), and ongoing relevant work at Standard Development Organizations (SDOs).

Two sources of standards development were reviewed:

1. A list of standards that have been deemed relevant by NIST for smart grid implementation were identified. This list provides a starting point and reference source for all standards that have been considered in smart grid implementation. Then the extent of acceptance of the standards were evaluated, through industry experience in industry conferences, sharing of lessons learned, etc. to develop a profile of the most prevalent standards that have actually been included in reference architectures around the industry.
2. Standardization activities within IEC Technical Committee 57 (TC57) and associated working groups (WG): IEC TC57 is chartered with developing standards for electric power system management and associated information exchange in the areas of generation, transmission and distribution real-time operations and planning, as well as information exchange to support wholesale energy market operations. The object models, services, and protocols within TC57 are described as to how they relate to each other through a reference architecture for power system information exchange. Several standards developed through TC57 are included in the NIST list of standards.

From the review, a "qualified" list of standards and protocols are identified that represent industry practices, that are used to benchmark with SDG&E practices currently in place with its "as-is" architecture. The difference between the two represent the gaps that exist in the SDG&E architecture to support the needed protocols and standards.

2.4.1 Standards included in NIST Smart Grid Roadmap

The NIST list of standards now identifies 81 smart grid-listed standards, shown in Figure 2-6. Many other standards are undergoing development and require modifications, some of which are being addressed through the Smart Grid Interoperability Panel Priority Action Plans (SGIP PAPs). They may not be included in the NIST Catalog of Standards (CoS) at this time, but have been listed in Reference [2] as a relevant standard. The SGIP SGAC and SGCC, are also addressing some of these needed modifications. Experience gained with devices designed to meet the requirements of the standards from interoperability testing and certification activities managed by Interoperability Testing and Certification Authorities (ITCAs) will also influence the changes to these standards.

SGIP's Smart Grid Catalog of Standards

Full List of Standards by Entry Number

SGIP Catalog of Standards	Date
1. ANSI C12.1-2008 listed Sept 5 2012	10/15/2014
2. ANSI C12.18-2006 listed Sept 5 2012	10/15/2014
3. ANSI C12.19-2008 listed Sept 5 2012	10/15/2014
4. ANSI C12.19-2012-dated 2014-10-07	08/17/2015
5. ANSI C12.20-2010 listed Sept 5 2012	10/15/2014
6. ANSI C12.21-2006 listed Sept 5 2012	10/15/2014
7. ANSI C12.22-2008 listed Sept 5 2012	10/15/2014
8. ASHRAE 135-2010 BACnet listed Nov 21 2011	10/15/2014
9. CEA-709.1-C-2014-02-14rev1	10/15/2014
10. CEA-709.2-A-2014-02-14rev1	10/15/2014
11. CEA-709.3-2014-02-14rev1	10/15/2014
12. CEA-709.4-2014-02-14rev1	10/15/2014
13. CEA-852.1-2014-02-14rev1	10/15/2014
14. CEA-852-B-2014-02-14rev1	10/15/2014
15. CEA-CEDIA-CEB29- dated 2012-03-01v1	10/15/2014
16. IEC 15067.3-dated 2012-11-05	08/17/2015
17. IEC_60870-6-503 listed Sept 5 2012	10/15/2014
18. IEC 60870-6-702-1998 listed Sept 5 2012	10/15/2014
19. IEC 60870-6-802	10/15/2014
20. IEC_61850-1	10/15/2014
21. IEC 61850-10	10/15/2014
22. IEC 61850-2	10/15/2014
23. IEC 61850-3	10/15/2014
24. IEC 61850-4	10/15/2014
25. IEC 61850-5	10/15/2014
26. IEC 61850-6	10/15/2014
27. IEC 61850-7-1	10/15/2014
28. IEC 61850-7-2	10/15/2014
29. IEC 61850-7-3	10/15/2014
30. IEC 61850-7-4	10/15/2014
31. IEC 61850-7-410	10/15/2014
32. IEC 61850-7-420	10/15/2014
33. IEC 61850-8-1	10/15/2014
34. IEC 61850-90-5	10/15/2014
35. IEC 61850-9-2	10/15/2014
36. IEC 62351-1	10/15/2014
37. IEC 62351-2	10/15/2014
38. IEC 62351-3	10/15/2014
39. IEC 62351-4	10/15/2014
40. IEC 62351-5	10/15/2014
41. IEC 62351-6	10/15/2014
42. IEC 62351-7	10/15/2014

SGIP Catalog of Standards	Date
43. IEC 62351-8-dated 2014-03-21	08/17/2015
44. IEC-62541 Parts 1-7 listed Nov 2013	10/15/2014
45. IEEE 1377-dated 2011-02-02	08/17/2015
46. IEEE 1701	10/15/2014
47. IEEE 1815-2010 listed Dec 31 2011	10/16/2014
48. IEEE 1901-2010 listed Jan 31 2013	10/16/2014
49. IEEE C37.238	10/16/2014
50. IEEE C37.239-2010 listed May 4 2012	10/16/2014
51. IEEE1901.2-dated 2011-09-02L	08/17/2015
52. IETF RFC 6272 listed July 7 2011	10/16/2014
53. ITU-T G.9960	10/16/2014
54. ITU-T G.9972	10/16/2014
55. MultiSpeak® Security V1.0-dated 2013-12-05	10/16/2014
56. MultiSpeak® V3.0-dated 2013-12-05v1	10/16/2014
57. NAESB REQ 19	10/16/2014
58. NAESB REQ 21	10/16/2014
59. NAESB REQ 22	10/16/2014
60. NEMA SG-AMI 1	10/16/2014
61. NISTIR 7628 listed Sept 5 2012	10/16/2014
62. NISTIR 7761 listed July 7 2011	10/16/2014
63. NISTIR 7761-dated 20130920R1	10/16/2014
64. NISTIR 7862	10/16/2014
65. NISTIR 7943-dated 20140615	8/17/2015
66. OASIS EMIX listed Dec 31 2011	10/16/2014
67. OASIS WS	10/16/2014
68. OASIS-Energy Interop	10/16/2014
69. OpenADR-2 0a-dated 2012-08-17-sh	10/16/2014
70. OpenADR-2 0b-dated 2012-08-17rev2	10/16/2014
71. SAE J1772-2010 listed July 7 2011	10/16/2014
72. SAE J2836 Use Cases (1-3) listed July 7 2011	10/16/2014
73. SAE J2847-1 listed Oct 14 2011	10/16/2014
74. SEP2 0-dated 2013-12-02 update	10/16/2014
75. SG AMI-1	10/16/2014
76. SGIP 2011-0008-1	10/16/2014
77. ANSI/ASHRAE/NEMA Standard # 201p (FSGIM)	03/01/2017
78. ANSI/CTA-2045	03/01/2017
79. ITU-T G.9903	03/01/2017
80. NAESB RMQ.26	03/01/2017
81. NEMA Standards Publication SG-IPRM 1-2016	03/01/2017

Figure 2-6. SGIP's Smart Grid catalog of standards (as of 3/13/2017).[8]

Of the 81 NIST Smart Grid listed standards, the Quanta team has identified approximately 40 of those listed standards, and at least 10 more relevant standards (not listed in the CoS at this time) that would be more closely related to reference architecture requirements for SDG&E Distribution Operations. The following sections summarize the standards that are listed in the NIST catalog of Standards that may be relevant to SDG&E Distribution Operations.

2.4.1.1 IEC-60870-6

IEC published standard is referred to as TASE.2, comprising 60870-6-503, -505, -702, and -802. The major objectives of TASE.2 are to provide (1) increased functionality and to (2) maximize the use of

[8] List downloaded (3/13/2017) from http://www.sgip.org/wp-content/uploads/SGIPs-Catalog-of-Standards-Complete-List-of-Entries_2017.pdf

existing OSI-compatible protocols, specifically the Manufacturing Messaging Standard (MMS) protocol stack. TASE.2 provides a utility-specific layer over MMS. In addition to SCADA data and device control functionality, the TASE.2 standards also provide for exchange of information messages (i.e., unstructured ASCII text or short binary files) and structured data objects, such as transmission schedules, transfer accounts, and periodic generation reports. This standard is also known as the Inter-control center protocol (ICCP), from the name given by the EPRI project that sponsored the development of the draft specifications for this standard. Its use is prevalent in communications between external control centers. Table 2-5 summarizes the IEC 60870-6 standards.

Table 2-5. IEC 60870 standards

Standard	Application	Comments
IEC 60870-6 -503 Telecontrol Application Service Element 2 (TASE.2)	Defines the messages sent between control centers of different utilities. (T,D)	Open, mature standard developed and maintained by an SDO. It is widely implemented with compliance testing. This is part of the IEC 60870 Suite of standards. It is used in almost every utility for inter-control center communications between SCADA and/or Energy Management System (EMS) systems. It is supported by most vendors of SCADA and EMS systems
IEC 60870-6-702 Telecontrol Equipment and Systems - Part 6: Telecontrol protocols compatible with ISO standards and ITU-T recommendations - Section 702: Functional profile for providing the TASE.2 application service in end systems	Defines a standard profile, or set of options for implementing the application, presentation, and session layers. (T)	This is known as an A-profile. For a complete protocol implementation of TASE.2, this A-profile must interface to a connection-oriented transport profile, or T-profile that specifies the transport, network and possibly data link layers. A T-profile that is commonly used with this standard includes RFC1006, TCP, IP, and Ethernet. This section of the standard defines the Protocol Implementation Conformance Statements (PICS) for TASE.2, including tables specifying which services and objects are mandatory and optional for compliance with the standard.
IEC 60870-6-802 Telecontrol Equipment and Systms - Part 6: Telecontrol protocols compatible with ISO standards and ITU-T recommendations - Section 802: TASE.2 Object Models	Standard for Communications between electric power control centers. Formerly known as Inter control center Protocol (ICCP), the standard is used for communication of electric power system status and control messages between power control centers. (T)	This part of the standard defines the object models used at the application layer of the protocol. It includes data objects for basic Supervisory Control and Data Acquisition (SCADA) as well as specific objects for control center concepts such as Transfer Accounts, Device Outages, and Power Plants.

2.4.1.2 IEC 61850

The IEC 61850 standard is a suite of protocols that address communications networks and systems in substations. This standard defines communications within transmission and distribution substations for automation and protection. It is being extended to cover communications beyond the substation to integration of distributed resources and between substations.

IEC 61850 is an open standard with conformance testing that is developed and maintained by an SDO. It has been widely adopted world-wide and is starting to be adopted in North America. Developed initially for field device communications within substations, this set of standards is now being extended to communications between substations, between substations and control centers, and including hydroelectric plants, DER, and synchrophasors. It is also adapted for use in wind turbines (IEC 61400-25) and switchgears (IEC 62271-3).

Descriptions of the individual parts of the IEC 61850 specification are shown in Table 2-6 below.

Table 2-6. IEC 61850 family of standards

Standard	Comments
IEC 61850-1 and -2	Part 1 of the standard, provides an overview of the other parts of the standard and an introduction to key concepts used in the rest of the standard, such as logical nodes. Part 2 of the standard is the glossary.
IEC 61850-3	Part 3 of IEC 61850 applies to substation automation systems (SAS). It describes the communication between intelligent electronic devices (IEDs) in the substation and the related system requirements. The specifications of this part pertain to the general requirements of the communication network, with emphasis on the quality requirements. It also deals with guidelines for environmental conditions and auxiliary services, with recommendations on the relevance of specific requirements from other standards and specifications.
IEC 61850-4	The specifications of this part pertain to the system and project management with respect to the following: • Engineering process and its supporting tools • Life cycle of the overall system and its IEDs • Quality assurance beginning with the development stage and ending with discontinuation and decommissioning of the SAS and its IEDs. The requirements of the system and project management process and of special supporting tools for engineering and testing are described. The IEC 61850-4 covers system and project management requirements for Utility Automation Systems, which implies a broader scope than the substation automation communication equipment only. However, the language in the document is heavily based on Substation Automation.
IEC 61850-5	This part of IEC 61850 applies to Substation Automation Systems (SAS). It standardizes the communication between intelligent electronic devices (IEDs) and the related system requirements. The specifications of this part refer to the communication requirements of the functions being performed in the substation automation system and to device models. All known functions and their communication requirements are identified.
IEC 61850-6	Specifies a file format for describing communication-related IED (Intelligent Electronic Device) configurations and IED parameters, communication system configurations, switch yard (function) structures, and the relations between them. The main purpose of this format is to exchange IED capability descriptions, and SA system descriptions between IED engineering tools and the system engineering tool(s) of different manufacturers in a compatible way. The defined language is called System Configuration description Language (SCL). The IED and communication system model in SCL is according to IEC 61850-5 and IEC

Standard	Comments
	1850-7-x. SCSM specific extensions or usage rules may be required in the appropriate parts. The configuration language is based on the Extensible Markup Language (XML) version 1.0 (see XML references in Clause 2). This standard does not specify individual implementations or products using the language, nor does it constrain the implementation of entities and interfaces within a computer system. This part of the standard does not specify the download format of configuration data to an IED, although it could be used for part of the configuration data.
IEC 61850-7-1	The purpose of this part of the IEC 61850 series is to provide – from a conceptual point of view – assistance to understand the basic modeling concepts and description methods for: • Substation-specific information models for power utility automation systems, • Device functions used for power utility automation purposes, and • Communication systems to provide interoperability within power utility facilities Furthermore, this part of the IEC 61850 series provides explanations and provides detailed requirements relating to the relation between IEC 61850-7-4, IEC 61850-7-3, IEC 61850-7-2 and IEC 61850-5. This part explains how the abstract services and models of the IEC 61850-7-x series are mapped to concrete communication protocols as defined in IEC 61850-8-1.
IEC 61850-7-2	This part of IEC 61850 applies to the ACSI communication for utility automation. The ACSI provides the following abstract communication service interfaces: a. Abstract interface describing communications between a client and a remote server for the following: ▪ Real-time data access and retrieval ▪ Device control ▪ Event reporting and logging ▪ Setting group control ▪ Self-description of devices (device data dictionary) ▪ Data typing and discovery of data types ▪ File transfer b. Abstract interface for fast and reliable system-wide event distribution between an application in one device and many remote applications in different devices (publisher/subscriber) and for transmission of sampled measured values (publisher/subscriber).
IEC 61850-7-3	This part of IEC 61850 specifies constructed attribute classes and common data classes related to substation applications. In particular, it specifies the following: • Common data classes for status information • Common data classes for measured information • Common data classes for control • Common data classes for status settings • Common data classes for analogue settings • Attribute types used in these common data classes This International Standard is applicable to the description of device models and functions of substations and feeder equipment.
IEC 61850-7-4	This part specifies the abstract information model of devices and functions, consisting of data objects contained in Logical Nodes (LNs). This part was initially just for substation automation, but has been expanded to include the common Logical Nodes used in many different domains, including:

Standard	Comments
	• Intra-substation information exchanges • Substation-to-substation information exchanges • Substation-to-control center information exchanges • Power plant-to-control center information exchanges • Information exchange for distributed generations • Information exchange for distributed automations • Information exchange for metering This part also specifies normative naming rules for multiple instances and private, compatible extensions of logical node (LN) classes and data object (DO) names.
IEC 61850-7-410	This part of IEC 61850 specifies the additional common data classes, logical nodes and data objects required for the use of IEC 61850 in a hydropower plant. The Logical Nodes and Data Objects defined in this part of IEC 61850 belong to the following fields of use: • <u>Electrical functions</u>. This group includes LN and DO used for various control functions, essentially related to the excitation of the generator. New LN and DO defined within this group are not specific to hydropower plants; they are more or less general for all types of larger power plants. • <u>Mechanical functions</u>. This group includes functions related to the turbine and associated equipment. The specifications of this document are intended for hydropower plants, modifications might be required for application to other types of generating plants. Some more generic functions are defined under Logical Node group K. • <u>Hydrological functions</u>. This group of functions includes objects related to water flow, control and management of reservoirs and dams. Although specific for hydropower plants, the LN and DO defined here can also be used for other types of utility water management systems. • <u>Sensors</u>. A power plant will need sensors providing measurements of other than electrical data. With a few exceptions, such sensors are of general nature and not specific for hydropower plants.
IEC 61850-7-420	This International Standard defines the IEC 61850 information models to be used in the exchange of information with distributed energy resources (DER), which comprise dispersed generation devices and dispersed storage devices, including reciprocating engines, fuel cells, microturbines, photovoltaics, combined heat and power, and energy storage. The IEC 61850 DER information model standard utilizes existing IEC 61850-7-4 logical nodes where possible, but also defines DER-specific logical nodes where needed.
IEC 61850-8-1	IEC 61850-8-1 maps the: • Abstract service models defined in IEC 61850-7-2 as “Abstract Communication Services Interface (ACSI)”, including the Generic Object-Oriented Substation Event (GOOSE) and Sampled Values (SV) messages • Common data classes (CDCs) defined in IEC 61850-7-3 • Data objects in Logical Nodes (LNs) defined in the IEC 61850-7-4, 7-410, and 7-420 to the “bits and bytes” protocols of the Manufacturing Message Specification (MMS) at the ISO/OSI Application Layer, that runs over IEC 8802-3 (commonly referred to as Ethernet) at the ISO/OSI Data Link Layer • Time synchronization uses the Simple Network Time Protocols (SNTP) protocol • Different profiles are established for different types of messages, ranging from the very fast GOOSE event messages and rapid continuous sampled values messages running directly over Ethernet, to special time synchronization interactions over UDP, to the

Standard	Comments
	normal information exchange messages running over TCP/IP The standard also addresses additional mapping issues, including file transfers, the system configuration language, conformance, multicast, and timing issues.
IEC 61850-9-2	IEC 61850 supports “sampled values” which are continuously streaming raw measurements from sensors, e.g., voltage measurements from Potential Transformers (PTs) or water flow measurements in hydro plants. This standard maps the abstract services defined in IEC 61850-7-2 for retrieving these sampled values to the (A-Profile) Manufacturing Message Specification (MMS) as standardized in IEC 61850-8-1 and to (T-Profile) TCP/IP over (essentially) Ethernet over fiber optic media. Other media may also be used, but are not specified in this document.
IEC 61850-10	IEC 61850 was originally focused on substation automation. This part defines the conformance testing requirements and measurement techniques for ensuring optimal performance for implementations of substation automation using IEC 61850. The testing covers the following: • General testing plan and procedure requirements • Quality assurance requirements • Use of SCL files • Documentation and test reports • Positive and negative test cases for the services defined in IEC 61850-7-2 • Accuracy of time synchronization • Performance tests
IEC 61850-90-5	This technical report is a part of the IEC 61850 series of standards that adds a method for exchanging synchrophasor data between PMUs, PDCs, WAMPAC (Wide Area Monitoring, Protection, and Control) systems, and between control center applications. The data, to the extent covered in IEEE C37.118.2 - 2011, is transported in a way that is compliant to the concepts of IEC 61850. This document also provides routable profiles for IEC 61850-8-1 GOOSE and IEC 61850-9-2 SV packets. These routable packets can be utilized to transport general IEC 61850 data as well as synchrophasor data.

2.4.1.3 IEEE 1815 (DNP3)

This standard is used for substation and feeder device automation, as well as for communications between control centers and substations. IEEE 1815 is an open, mature, widely implemented specification initially developed and supported by a group of vendors, utilities, and other users, and now maintained by an SDO.

IEEE has adopted as an IEEE standard, IEEE Std 1815-2010, excluding the cybersecurity part which is being updated by IEEE Substation Committee Working Group (WG) C12.

2.4.1.4 IEEE C37.238-2011

This standard is IEEE Standard Profile for Use of IEEE 1588 Precision Time Protocol in Power System Applications, for Ethernet communications for power systems.

This standard specifies a common profile for use of IEEE 1588-2008 Precision Time Protocol (PTP) in power system protection, control, automation and data communication applications utilizing an Ethernet communications architecture.

The profile specifies a well-defined subset of IEEE 1588-2008 mechanisms and settings aimed at enabling device interoperability, robust response to network failures, and deterministic control of delivered time quality. It specifies the preferred physical layer (Ethernet), higher level protocol used for PTP message exchange and the PTP protocol configuration parameters. Special attention is given to ensuring consistent and reliable time distribution within substations, between substations, and across wide geographic areas. (Source: IEEE PC37.238 D4.0 – Scope Statement).

IEEE PSRC Subcommittee Working Group H7 has been developing the standard. C37.238, which will incorporate IEEE 1588, the Standard for time management and clock synchronization across the Smart Grid for equipment needing consistent time management, as required for profiles for electric power systems.

2.4.1.5 IEEE C37.239-2010

This Standard defines the Common Format for Event Data Exchange (COMFEDE) for Power Systems, for the interchange of power system event data.

A common format for data files used for the interchange of various types of event data collected from electrical power systems or power system models is defined. Extensibility, extension mechanisms, and compatibility of future versions of the format are discussed. An XML schema is defined. A sample file is given. It doesn't define what is transferred via communications. It is only a file format for offline analysis and data exchange.

2.4.1.6 MultiSpeak V3.0

The MultiSpeak initiative is a collaborative effort between the National Rural Electric Cooperative Association (NRECA) and software vendors serving the electric utility industry [10]. MultiSpeak is currently in use in the daily operations of more than 800 electric cooperatives, investor-owned utilities, municipals, and public power districts in at least 21 different countries. However, with the incorporation of web services and especially the addition of the service bus architecture, the capabilities of MultiSpeak are scalable and the uses are not limited to smaller utilities. This recognition has led to a growing interest in the power of MultiSpeak among municipal and investor-owned utilities.

The Initiative has developed a specification package that defines standard data interfaces between software applications commonly used by small electric utilities. MultiSpeak defines software interfaces, data objects and message structures. These interface, data, and message definitions permit vendors to write a common interface that facilitates communication with other types of software.

MultiSpeak 3.0 supports the following back-office software applications:

- Customer Information Systems (CIS)
- Geographic information systems (GIS)
- Engineering analysis (EA)
- Interactive voice response systems (IVR)
- Automated staking

- Supervisory control and data acquisition (SCADA)
- Automated meter reading (AMR)
- Outage management (OM)
- Load management (LM)
- Customer relationship management (CRM)

Version 3 includes support for real-time integration using web services.

Security can be implemented over a MultiSpeak interface with MultiSpeak security V1.0, also included in the SGIP CoS.

2.4.1.7 Cyber Security: NISTR 7628

NISTR 7628 is a guideline first published by NIST in 2010. It was developed through a participatory public process that, starting in March 2009, included several workshops as well as weekly teleconferences, all of which were open to all interested parties. NISTR 7628, Revision 1 was released in September 2014 and includes updates to the document for such areas as security architecture and privacy.

The guidelines are not prescriptive, nor mandatory. Rather they are advisory, intended to facilitate each organization's efforts to develop a cybersecurity strategy effectively focused on prevention, detection, response, and recovery. The guideline includes the following:

- An overview of the cybersecurity strategy used by the Cyber Security Working Group (CSWG) to develop the high-level cybersecurity smart grid requirements;
- A tool for organizations that are researching, designing, developing, implementing, and integrating smart grid technologies—established and emerging;
- An evaluative framework for assessing risks to smart grid components and systems during design, implementation, operation, and maintenance; and
- A guide to assist organizations as they craft a smart grid cybersecurity strategy that includes requirements to mitigate risks and privacy issues pertaining to smart grid customers and uses of their data.

NISTIR 7628 Guidelines for Smart Grid Cybersecurity, consists of 3 volumes:

- Vol 1: *Smart Grid Cybersecurity Strategy, Architecture, and High-Level Requirements* (http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol1.pdf)
- Vol 2: *Privacy and the Smart Grid* (http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol2.pdf)
- Vol 3: *Supportive Analyses and References* (http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol3.pdf)

2.4.1.8 Cyber Security: IEC 62351 family of standards

The IEC 62351 Family of standards: Power systems management and associated information exchange - Data and communications security (shown in Table 2-7) is an open standard, developed and maintained by an SDO. Defines security requirements for power system management and information exchange, including communications network and system security issues, Transmission Control Protocol (TCP) and Manufacturing Messaging Specification (MMS) profiles, and security for Inter-control center Protocol

(ICCP) and substation automation and protection. It is for use in conjunction with related IEC standards, but has not been widely adopted yet.

Table 2-7. IEC 62351 family of cyber security standards

Standard	Description
IEC 62351-1	Provides an introduction to the remaining parts of the IEC 62351 series, primarily to introduce the reader to various aspects of information security as applied to power system operations. The scope of the IEC 62351 series is information security for power
IEC 62351-2	Part 2 of the IEC 62351 series covers the key terms used in the series, including references to original definitions of cyber security terms and communications terms.
IEC 62351-3	Part 3 of the IEC 62351 series provides technical specifications on ensuring the confidentiality, tamper detection, and message level authentication for SCADA and other telecontrol protocols which use TCP/IP as a message transport layer between communicating entities. TCP/IP-based protocols are secured through specification of the messages, procedures, and algorithms of Transport Layer Security (TLS).
IEC 62351-4	Part 4 of the IEC 62351 series provides specifications to secure information transferred when using ISO 9506, Manufacturing Message Specification (MMS)-based applications; specifying which procedures, protocol extensions, and algorithms to use in MMS to provide security.
IEC 62351-5	Part 5 of the IEC 62351 series specifies messages, procedures, and algorithms that apply to the operation of all protocols based on/derived from IEC 60870-5, Telecontrol equipment and systems-Part 5: Transmission protocols. The focus of this 62351-5 is on the application layer authentication and security-issues that are a result of application layer authentication. While authentication of sources and receivers is considered the most important requirement and confidentiality is not considered important, encryption can be included by combining this standard with other security standards, such as IEC 62351-3, TLS.
IEC 62351-6	Part 6 of the IEC 62351 series addresses security for IEC 61850 profiles through specification of messages, procedures, and algorithms. IEC 61850 specifies a number of different profiles which have different constraints, performance requirements, and security needs, but the primary requirement is for authentication of sources of data, receivers of data, and data integrity. Therefore, different security options are specified.
IEC 62351-7	Part 7 of the IEC 62351 series provides an abstract model of network and system data elements that should be monitored and controlled. Its focus is network and system management, one area among many possible areas of end-to-end information security. The primary focus is the enhancement of overall management of the communications networks supporting power system operations, by specifying monitoring and control of communication networks and systems. Intrusion detection and intrusion prevention are addressed.
IEC 62351-8	Part 8 of the IEC 62351 series specifies role-based access control (RBAC) requirements. RBAC is an alternative to the all-or-nothing super-user model. RBAC is in keeping with the security principle of least privilege, which states that no subject should be given more rights than necessary for performing that subject's job. RBAC enables an organization to separate super-user capabilities and package them into special user accounts termed roles for assignment to specific individuals according to their job needs.

2.4.1.9 Organization for the Advancement of Structured Information Standard (OASIS)

2.4.1.9.1 Energy Interoperation (EI)

Energy interoperation describes an information model and a communication model to enable demand response and energy transactions. XML vocabularies provide for the interoperable and standard exchange of: DR and price signals, bids, transactions and options, and customer feedback on load predictability and generation information.

This standard uses the EMIX information model for price and product as payload information. The DR specification is built on a unified model of retail (OpenADR) and wholesale (input from the ISO/RTO Council) DR. OpenADR 2.0 is a profile on EI.

2.4.1.9.2 EMIX (Energy Market Information eXchange)

EMIX provides an information model to enable the exchange of energy price, characteristics, time, and related information for wholesale energy markets, including market makers, market participants, quote streams, premises automation, and devices.

2.4.1.9.3 WS-Calendar

This is an application for XML serialization of IETF iCalendar for use in calendars, buildings, pricing, markets, and other environments. A communication specification used to specify schedule and interval between domains.

WS-Calendar describes a limited set of message components and interactions providing a common basis for specifying schedules and intervals to coordinate activities between services. The specification includes service definitions consistent with the OASIS SOA Reference Model and XML vocabularies for the interoperable and standard exchange of:

- Schedules, including sequences of schedules
- Intervals, including sequences of intervals

2.4.1.10 Other NIST cataloged standards that could impact distribution operations

Within the NIST/SGIP smart grid catalog of standards there are other standards that may indirectly impact SDG&E Distribution Operations. These standards define the interoperability requirements between customers, service providers, or other cross cutting technologies such as communications transport. Information models in the customer and service provider domains may ultimately provide input to Distribution operations to make more informed decisions on management of the network. Table 2-8 provides a list of other NIST standards that could impact SDG&E distribution operations.

Table 2-8. Other standards in NIST CoS that could impact Distribution Operations

Standard	Application	Smart Grid Conceptual Architecture Domains
ANSI C12 Suite	Standards for electricity metering. There are many sections to the ANSI C12 standard, each covering specific aspects of metering.	Customer, Service provider

Standard	Application	Smart Grid Conceptual Architecture Domains
IEEE 1901-2010 (ISP) and International Telecommunications Union Telecommunication Standardization Sector (ITU-T) G.9CCR2 (06/2010)	Coexistence mechanism for wireline home networking transceivers," specify Inter-System Protocol (ISP) based Broadband (> 1.8 MHz) PLC (BB-PLC) coexistence mechanisms to enable the coexistence of different BB-PLC protocols for home networking.	Customer
NAESB REQ18, WEQ19 Energy Usage Information	The standards specify two-way flows of energy usage information based on a standardized information model.	Customer, Service provider
NAESB REQ-21 Energy Services Provider Interface (ESPI)	ESPI builds on the NAESB Energy Usage Information (EUI) Model and, subject to the governing documents and any requirements of the applicable regulatory authority, will help enable retail customers to share energy usage information with third parties who have acquired the right to act in this role.	Customer, Service provider
NAESB REQ-22 Third Party Access to Smart Meter-based Information Business Model Practices	Establishes voluntary Model Business Practices for Third Party access to Smart Meter-based information." These business practices are intended only to serve as flexible guidelines rather than requirements, with the onus on regulatory authorities or similar bodies to establish the actual requirements. They are also not intended for any billing or collection activities.	Customer, Service provider
NAESB RMQ.26 Open Field Message Bus (Open FMB)	The OpenFMB™ framework provides a specification for power systems field devices to leverage a non-proprietary and standards-based reference architecture, which consists of internet protocol (IP) networking and Internet of Things (IoT) messaging protocols. The framework supports Distributed Energy Resources that communicate based on a common schematic definition and then can process the data locally for action (control, reporting). OpenFMB™ supports field-based applications that enable: • Scalable peer-to-peer publish/subscribe architecture • Data-centric, rather than device-centric, communication including support for harmonized system and device data • Distributed operations augmenting centralized control	Distribution, Operations
Open Automated Demand 2.0 Response (OpenADR)	The specification defines messages exchanged between the Demand Response (DR) Service Providers (e.g., utilities, independent system operators (ISOs) and customers for price-responsive and reliability-based DR.	Operations, service providers
Smart Energy Profile 2.0-2013	Home Area Network (HAN) Device Communications and Information Model.	Customer

Standard	Application	Smart Grid Conceptual Architecture Domains
Internet Protocol Suite, Request for Comments (RFC) 6272, Internet Protocols for the Smart Grid.	Internet Protocols for IP-based Smart Grid Networks IPv4/IPv6 are the foundation protocol for delivery of packets in the Internet network. Internet Protocol version 6 (IPv6) is a new version of the Internet Protocol that provides enhancements to Internet Protocol version 4 (IPv4) and allows a larger address space.	Cross-cutting communications transport layer that supports smart grid applications
SAE J2836/1: Use Cases for Communication Between Plug-in Vehicles and the Utility Grid	This document establishes use cases for communication between plug-in electric vehicles and the electric power grid, for energy transfer and other applications.	Requirements

2.4.2 Other relevant standards that could impact distribution operations

There are several standards not currently in the NIST catalog of Standards, but have been recognized through other Smart Grid Standards organizations, or identified by NIST as relevant to the Smart Grid roadmap, but may be undergoing development or modifications. Experience gained with devices designed to meet the requirements of the standards from interoperability testing and certification activities managed by Interoperability Testing and Certification Authorities (ITCAs) will also influence the changes to these standards. The following sections summarize those standards.

2.4.2.1 IEC 60870-5

Not included in the NIST Catalog of Standards is IEC 60870 part 5, known as Transmission protocols. While these protocols may be transparent to SDG&E Distribution Operations, they are listed here for reference. The IEC TC 57 WG3 have developed a protocol standard for telecontrol, teleprotection, and associated telecommunications for electric power systems. The result of this work is IEC 60870-5. Seven documents specify the base IEC 60870-5:

- IEC 60870-5-1 Transmission Frame Formats
- IEC 60870-5-2 Data Link Transmission Services
- IEC 60870-5-3 General Structure of Application Data
- IEC 60870-5-4 Definition and Coding of Information Elements
- IEC 60870-5-5 Basic Application Functions
- IEC 60870-5-6 Guidelines for conformance testing for the IEC 60870-5 companion standards
- IEC TS 60870-5-7 Security extensions to IEC 60870-5-101 and IEC 60870-5-104 protocols (applying IEC 62351)

The IEC TC 57 has also generated companion standards:

- IEC 60870-5-101 Transmission Protocols - companion standards especially for basic telecontrol tasks
- IEC 60870-5-102 Transmission Protocols - Companion standard for the transmission of integrated totals in electric power systems (this standard is not widely used)

- IEC 60870-5-103 Transmission Protocols - Companion standard for the informative interface of protection equipment
- IEC 60870-5-104 Transmission Protocols - Network access for IEC 60870-5-101 using standard transport profiles
- IEC TS 60870-5-601 Transmission protocols - Conformance test cases for the IEC 60870-5-101 companion standard
- IEC TS 60870-5-604 Conformance test cases for the IEC 60870-5-104 companion standard

IEC 60870-5-101/102/103/104 are companion standards generated for basic telecontrol tasks, transmission of integrated totals, data exchange from protection equipment & network access of IEC-101 respectively. IEC-101 is similar to the basic serial communications protocol, while IEC-104 utilizes network protocols such as TCP/IP.

2.4.2.2 IEC 61968 application integration at electric utilities

The IEC 61968/61970 families of standards define information exchanged among control center systems using common information models [3] [11]. They define application-level energy management system interfaces and messaging for distribution grid management in the utility space.

IEC WG 14 was formed to address the need for standards for System Interfaces for Distribution Management Systems (SIDMS). The IEC 61968 series is intended to facilitate inter-application integration of the various distributed software application systems supporting the management of utility electrical distribution networks. These standards define requirements, integration architecture, and interfaces for the major elements of a utility's Distribution Management System (DMS) and other associated external IT systems. Examples of DMS include Asset Management Systems, Work Order Management Systems, Geographic Information Systems, Customer Information Systems, while Customer Resource Management is an example of an external IT system interface. The message-based technology used to mesh these applications together into one consistent framework is referred to as Enterprise Application Integration (EAI); IEC 61968 guides the utility's use of EAI.

Specific Parts of the IEC 61968 Specification include:

- IEC 61968-1 – Interface architecture and general requirements [Published]
- IEC 61968-2 – Glossary [Published]
- IEC 61968-3 – Interface for Network Operations [NO] [Published]
- IEC 61968-4 – Interfaces for Records and Asset management [AM] [Published]
- IEC 61968-5 – Interfaces for Operational planning & optimization [OP] [Under Development]
- IEC 61968-6 – Interfaces for Maintenance & Construction [MC] [Published]
- IEC 61968-7 – Interfaces for Network Extension Planning [NE] [Under Development]
- IEC 61968-8 – Interfaces for Customer Support [CS] [Published]
- IEC 61968-9 – Interface Standard for Meter Reading & Control [MR] [Published]
- IEC 61968-10 – Interfaces for Business functions external to distribution management [Retired]. This includes Energy management & trading [EMS], Retail [RET], Supply Chain & Logistics [SC], Customer Account Management [ACT], Financial [FIN], Premises [PRM] & Human Resources [HR]
- IEC 61968-11 – Common Information Model (CIM) Extensions for Distribution [Published]
- IEC 61968-12 – Common Information Model (CIM) Use Cases for 61968 [Retired]

- IEC 61968-13 – Common Information Model (CIM) RDF Model exchange format for distribution [Published]
- IEC 61968-14-1-3 to 14-1-10 [2] – Proposed IEC Standards to Map IEC61968 and MultiSpeak Standards [Under Development]
- IEC 61968-14-2-3 to 14-2-10 – Proposed IEC Standards to Create a CIM Profile to Implement MultiSpeak Functionality [Under Development]

2.4.2.2.1 Cyber security requirements

The standard focuses on the development of abstract information models, does not include any protocols, and assumes that any mapping of the abstract models to actual protocols or application components will utilize appropriate security. Methods and technologies used to implement functionality conforming to this CIM standard, including security, are considered outside of the scope of this standard; only the abstract models are specified in the IEC 61968 series.

2.4.2.3 IEEE C37.118

These set of standards defines phasor measurement units (PMUs) performance specifications and well as data transfer formats. The specification is targeted for the transmission and distribution Smart Grid conceptual architecture domains, but is not included in the SGIP catalog of standards. Table 2-9 below summarizes the components of the IEEE C37.118 Standard.

PMUs have widely been utilized in the transmission domain, but are now also finding application in distribution operations to monitor feeder and substation status. SDG&E is already utilizing PMUs on certain distribution applications.

Table 2-9. IEEE C37.118 standard

Standard	Application	Comments
IEEE C37.118.1-2011 IEEE Standard for Synchrophasor Measurements for Power Systems	Defines phasor measurement unit (PMU) performance specifications	Open standard, widely implemented, developed and maintained by an SDO. Standard is overseen by the IEEE Power System Relaying Committee (PSRC) Relaying Communications Subcommittee Working Groups H11 and H19. This standard is intended to become an IEEE/IEC dual-logo standard.
IEEE C37.118.2 Standard for synchrophasor data transfer for power systems	Defines communications for phasor measurement units (PMUs).	Some items not covered in C37.118-2005 include communication service modes, remote device configuration, dynamic measurement performance, and security IEEE PSRC WG C5 has developed a “Guide for Synchronization, Calibration, Testing, and Installation of Phasor Measurement Units (PMU) applied in Power System Protection and Control” based on the C37.118 standards and previous publications by North American Synchro-Phasor Initiative (NASPI) in these areas. They are part of PAP13 relating to harmonization of IEC 61850 and IEEE C37.118 standards (PAP13: Harmonization of IEEE C37.118 with IEC 61850 and Precision Time Synchronization -

2.4.2.4 IEEE 1547 Suite

This family of standards defines physical and electrical interconnections between the grid and distributed generation (DG) and storage. It is not included in the SGIP Catalog of Standards.

IEEE 1547 family of standards are open standards developed and maintained by an SDO with significant implementation for the parts covering physical/electrical connections. The parts of this suite of standards that describe messages are not as widely deployed as the parts that specify the physical interconnections. Many utilities and regulators require their use in systems. Revising and extending the IEEE 1547 family is a focus of PAP07, covering energy storage interconnections (PAP07: Energy Storage Interconnection Guidelines - http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP07Storag).

When applied to utility-interactive equipment, Underwriters Laboratories (UL) 1741, "Standard for Safety Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources," should be used in conjunction with 1547 and 1547.1 standards which supplement them. The products covered by these requirements are intended to be installed in accordance with the National Electrical Code, National Fire Protection Association (NFPA) 70.

2.4.2.5 Various cyber security standards

A set of Cyber security standards are identified in NIST SP 1108 document are shown and described in Table 2-10 below.

The most notable standard is the NERC Critical Infrastructure Protection (CIP) 002-009, that applies to the bulk electric system, but is also used as prudent practices is other sectors.

Table 2-10. Cyber security standards not in SGIP COS

Standard	Comments
Security Profile for Advanced Metering Infrastructure, v 1.0, Advanced Security Acceleration Project – Smart Grid, December 10, 2009 http://osgug.ucaiug.org/utilisec/amisec/Shared%20Documents/AMI%20Security%20Profile%20(ASAP-SG)/AMI%20Security%20Profile%20-%20v1_0.pdf	This document provides guidance and security controls to organizations developing or implementing AMI solutions. This includes the meter data management system (MDMS) up to and including the HAN interface of the smart meter. The Advanced Metering Infrastructure Security (AMI-SEC) Task Force was established under the Utility Communications Architecture International Users Group (UCAIug) to develop consistent security guidelines for AMI. This is not included in SGIP Catalog of Standards.
Department of Homeland Security (DHS), National Cyber Security Division. 2009, September. Catalog of Control Systems Security: Recommendations for Standards Developers. https://www.smartgrid.gov/document/dhs_national_cyber_security_division_catalog_control_systems_security_recommendations_stand	The catalog presents a compilation of practices that various industry bodies have recommended to increase the security of control systems from both physical and cyber attacks. This is a source document for the NIST Interagency Report NISTIR 7628, *Guidelines for Smart Grid Cyber Security* http://csrc.nist.gov/publications/nistir/ir7628/introduction-to-nistir-7628.pdf http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol1.pdf http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol2.pdf http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol3.pdf

Standard	Comments
	This is not included in SGIP Catalog of Standards.
DHS Cyber Security Procurement Language for Control Systems	The National Cyber Security Division of the Department of Homeland Security (DHS) developed this document to provide guidance to procuring cybersecurity technologies for control systems products and services. It is not intended as policy or standard. Because it speaks to control systems, its methodology can be used with those aspects of Smart Grid systems. This is a source document for the NIST Interagency Report NISTIR 7628, *Guidelines for Smart Grid Cyber Security* http://csrc.nist.gov/publications/nistir/ir7628/introduction-to-nistir-7628.pdf http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol1.pdf http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol2.pdf http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol3.pdf This is not included in SGIP Catalog of Standards.
IEC 61851: Electric vehicle conductive charging system - Part 1: General requirements http://webstore.iec.ch/webstore/webstore.nsf/Artnum_PK/44636	Applies to equipment for charging electric road vehicles at standard alternating current (ac) supply voltages (as per IEC 60038) up to 690 V and at direct current (dc) voltages up to 1 000 V, and for providing electrical power for any additional services on the vehicle if required when connected to the supply network. This is not included in SGIP Catalog of Standards.
IEEE 1686-2007 http://standards.ieee.org/findstds/standard/1686-2007.html	The IEEE 1686-2007 is a standard that defines functions and features to be provided in substation intelligent electronic devices (IEDs) for critical infrastructure protection programs. The standard covers IED security capabilities including the access, operation, configuration, firmware revision, and data retrieval. Open standard, developed and maintained by an SDO. Not widely implemented yet. This is not included in SGIP Catalog of Standards.
NERC Critical Infrastructure Protection (CIP) 002-011, and CIP-014	These standards cover organizational, processes, physical, and cybersecurity standards for the bulk power system. Mandatory standards for the bulk electric system. Currently being revised by the North American Electric Reliability Corporation (NERC). This is not included in SGIP Catalog of Standards.
NIST Special Publication (SP) 800-53 http://dx.doi.org/10.6028/NIST.SP.800-53r4 http://dx.doi.org/10.6028/NIST.SP.800-82	These standards cover cybersecurity standards and guidelines for federal information systems, including those for the bulk power system. Open standards developed by NIST. SP 800-53 defines security measures required for all U.S. government computers. SP800-82 defines security specifically for industrial control systems, including the power grid. This is not included in SGIP Catalog of Standards

2.4.2.6 IEC 62325: Common Information Model for energy market communications

IEC Working Group 16 is charged with developing a framework for deregulated energy market communications with a focus on the interface between utilities and the energy market. With the transition of monopoly energy supply structures to deregulated energy markets the function of the markets depends heavily on seamless e-business communication between market participants. Today EDIFACT or X12 messages, or propriety HyperText Markup Language (HTML) and XML solutions based on Internet technologies are being used. With the advent of new e-business technologies such as ebXML by UN/CEFACT (United Nations / Centre for Trade and Electronic Business) together with OASIS (Organization for the Advancement of Structured Information Standards), and Web Services by W3C, an energy market specific profile of these standards can be used for regional energy markets. This profile allows the re-use of proven core components and communication platforms across markets, thus saving cost and implementation time. Because some of these technologies are still developing, other technologies or converged technologies are not excluded for the future.

Besides general requirements and guidelines, this framework includes the business operational view and profiles of technical e-business communication architectures together with migration scenarios. It supports the communication aspects of all e-business applications in deregulated energy markets with emphasis on system operators. The business operational view includes the market communication aspects of system operator applications with interfaces to other market participants from trading over-supply to balancing planned generation and consumption, change of supplier, market services and billing.

- IEC 62325 consists of the following parts, detailed in separate IEC 62325 standard documents:
- IEC 62325-101: General guidelines
- IEC 62325-102: Energy market model example
- IEC 62325-301: Common information model (CIM) extensions for markets
- IEC 62325-351: CIM European market model exchange profile
- IEC 62325-450: Profile and context modeling rules
- IEC 62325-451-1: Acknowledgement business process and contextual model for CIM European market
- IEC 62325-451-2: Scheduling business process and contextual model for CIM European market
- IEC 62325-451-3: Transmission capacity allocation business process and contextual models for European market
- IEC 62325-451-4: Settlement and reconciliation business process, contextual and assembly models for European market
- IEC 62325-451-5: Problem statement and status request business processes, contextual and assembly models for European market
- IEC 62325-451-6: Publication of information on market, contextual and assembly models for European style market
- IEC 62325-452: North American style market profiles
- IEC 62325-501: General guidelines for use of ebXML
- IEC 62325-502: Profile of ebXML
- IEC 62325-503: Market data exchanges guidelines for the IEC 62325-351 profile
- IEC 62325-504: Utilization of web services for electronic data interchanges on the European energy market for electricity
- IEC 62325-550-2: Common dynamic data structures for North American style markets
- IEC 62325-552-1: Dynamic data structures for day ahead markets (DAM)

Whereas the parts of the current framework edition are restricted to the use of the ebXML technology, the planned parts are intended to convert the framework into a more open framework also taking into account other e-business technologies besides ebXML, such as Web Services. This will also include an abstraction service model with mapping to the various e-business technologies to hide the e-business technology actually used from the application. Further the standardization of basic business content including a market information model is planned, which could be the extension of the CIM model used in control centers.

IEC 62325-301:2014 specifies the common information model for energy market communications. The common information model (CIM) is an abstract model that represents all the major objects in an electric utility enterprise typically involved in utility operations and electricity market management. By providing a standard way of representing power system resources as object classes and attributes; along with their relationships; the CIM facilitates the integration of market management system (MMS) applications developed independently by different vendors; between entire MMS systems developed independently; or between an MMS system and other systems concerned with different aspects of market management; such as capacity allocation; day-ahead management; balancing; settlement; etc.

The IEC 62325 standards are part of a series of standards. IEC 61970 standards define the EMS application programming interfaces and the IEC 61968 standards define System interfaces for distribution management. IEC 62325-301 corresponds to the IEC 61970-301 and the IEC 61968-11 standards that describe parts of the common information model relevant to modeling interfaces for EMS, DMS and MMS systems. While there are multiple IEC standards dealing with different parts of the CIM, there is a single, unified information model comprising the CIM behind all these individual standards documents.

2.4.3 Harmonization efforts among standards

2.4.3.1 Harmonization activities related to IEC 61850

Several NIST PAPs (PAP07, PAP08, PAP12, and PAP13) are dedicated to further development work in various areas.

PAP07 has developed requirements to update IEC 61850-7-420 Distributed Energy Resource (DER) Information Models to include storage devices and Smart Grid functionality necessary to support high penetration of DER. PAP07 is also mapping the information models to application protocols including Smart Energy Profile (SEP2) and DNP3. The new information models requirements are included in the IEC Technical Report, IEC 61850-90-7 published in February 2013 and is also included in the modified normative standard that will follow.

Click on the referenced links for more information regarding harmonization efforts being addressed:

- PAP07: Energy Storage Interconnection Guidelines - http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP07Storage
- NIST PAP12 has been working on the mapping of IEEE 1815 (DNP3) to IEC 61850 objects, and it has resulted in a draft IEEE standard P1815.1 being completed in early 2011 for adoption by IEEE around mid-2011. (PAP12: Mapping IEEE 1815 (DNP3) to IEC 61850 Objects - http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP12DNP361850)
- NIST PAP13 was established to assist and accelerate the integration of standards (IEEE C37.118 and IEC 61850) that impact phasor measurement systems and applications that use

synchrophasor data, as well as implementation profiles for IEEE Std 1588 for precision time synchronization. (PAP13: Harmonization of IEEE C37.118 with IEC 61850 and Precision Time Synchronization - http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP1361850C27118HarmSynch)

- PAP8 is working on harmonizing this family of standards, the IEC 61970 family of standards (Common Information Model or CIM), and MultiSpeak for distribution grid management (PAP08: CIM/61850 for Distribution Grid Management - http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP08DistrObjMultispeak**).**

IEEE will split current IEEE C37.118-2005 into two parts in its new revision to facilitate the harmonization with IEC standards: C37.118.1 Standard for synchrophasor measurements for power systems aimed to become an IEEE/IEC dual-logo standard, and C37.118.2, Standard for synchrophasor data transfer for power systems to be harmonized with / transitioned to IEC 61850-90-5, which was published in May 2012.

2.4.3.2 Harmonization efforts with IEC 61968

PAP08, CIM for Distribution Grid Management,[9] focuses on the development of new Unified Modeling Language (UML) models for real-time and planning control center application information exchanges covering distribution functions Energy Management Systems (EMSs) and Distribution Management Systems (DMSs) such as:

- Fault Location, Isolation, and Service Restoration (FLISR), Volt/var/Watt Optimization (VVWO), Distribution Operation Model and Analysis (DOMA), Distribution Energy Resources (DER) management system, Load Management System (LMS), Planned Outage Management, Feeder Reconfiguration, etc, that are covered in IEC 61968 Parts 3, 5, 7, and the new DER Part (with no number assigned yet).
- Back office and asset management applications, such as covered in IEC 61968 Parts 4, 6, 8 & 9, including asset management (Part 4), maintenance & construction (Part 6), customer interactions (Part 8), and meter reading and control interactions (Part 9)
- Utility interactions with manually operated equipment (e.g., switching orders for field crews).

Since PAP08 also covers IEC 61850 for substation automation, there is close coordination of models under development for both standards to ensure that they are harmonized.

PAP14, Transmission and Distribution Power System Model Mapping,[10] is coordinating development of extensions of IEC 61968-11 models based on Smart Grid requirements. The tasks of PAP14 include: developing strategies to expand and integrate MultiSpeak, IEC 61850, IEC 61968, IEC 61970, IEEE PC37.237 (Time Tagging Standard), IEEE PC37.239 (Common Format for Event Data Exchange - COMFEDE) and the future IEEE Common Settings file format for Smart Grid Applications; developing a summary of information required from the power system for various Smart Grid applications; and mapping that information with the already defined models from MultiSpeak, IEC 61970, IEC 61968-11, and IEC 61850.

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[9] PAP8 CIM for Distribution Grid Management – for more information see http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP08DistrObjMultispeak .

[10] PAP14 Transmission and Distribution Power System Model Mapping – for more information see http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP14TDModels .

2.4.4 Summary and conclusions regarding standards and protocols

The industry has many standards that exist among several standards development organizations (SDO's) that may be applicable to multiple layers of the power systems architecture. The key goal is to identify the standards that can be tailored to support SDG&E's specific requirements and use cases. The NIST/SGIP activities maintaining the Catalog of Standards (CoS), as well as IEC TC57 work provides a well-tested source of standards for consideration in SDG&E's distribution operations architecture.

A key standard is the IEC 61850 protocol suite. It has been recognized at the substation and interoperable field connectivity. The IEC 61850 standard is also gaining industry acceptance for future architectures including DER integration. The extent of harmonization efforts that have included IEC 61850 show that the protocol suite is becoming a key building block in the future smart grid architecture.

IEC protocol standards also have an accompanying cyber security set of standards (IEC 62351) that can be used to provide optimal protection of assets through the implementation of harmonized cyber security practices, further protecting the overall reference architecture

2.5 Phase 2 – Task 4: Define architecture for SDG&E

The comprehensive, end-to-end, detail architecture needs to support the utility business domains and common enabling services, as well as utilizing data models and functional elements that assume a service-oriented process.

The primary business focus is Distribution Operations, and all business units that support this process. From the business perspective, a comprehensive architecture definition that will incorporate all layers of business domains with appropriate logical groupings of business capabilities providing related business functions while requiring similar skills and expertise is developed.

From the functional view, application services structural models are provided to help the engineers and system architects identify how to best deploy the various application services in SDG&E utility network infrastructure. A vertical architecture model representation is suggested. At the top of the model are elements needed to support external agencies (regulators, interchange and balancing authorities, etc.). At the bottom are the application services needed by end-user and behind the meter devices (smart appliances, PEV chargers, building energy managers, etc.). In between are several layers where application services may be located to support utility assets and distribution operation functionalities.

In addition, analytical analysis structure models, communication and data exchange platforms are incorporated in the reference architecture definition. These are important aspects of the architecture describing how applications, services and functionalities can be distributed across the whole distribution system. The distributed architecture has to also address issues of latency, scalability, interoperability and robustness.

2.5.1 Architecture governance

The current distribution operations system architecture is in a state of flux as mechanisms are being developed to integrate new devices and technologies into the system – among these DER devices and the accompanying management system. There are limitations with the current and planned architecture that present challenges to deploying more distribution automation applications and supporting large scale deployment of DER devices. Distributed control architecture will be investigating control architectures, concepts and methodologies that will broadly be applicable to all aspects of the advanced distribution automation to achieve further alignment and enhancement toward the performance metrics of the system.

To achieve the above objectives, the proposed target architecture will be developed based on three principles:

1. Component layer architecture based on a more distributed control
2. Use cases chosen for Phase 3 testing that are representative of the additional or new functions that may be required of the SDG&E organization to implement, operate, and maintain, and
3. Changes or Modifications to SDG&E business processes or functions to accommodate future requirements based on new services or changes at the information, communications, and component layers driven by implementation of standards or other architecture changes.

2.5.1.1 Distributed control architecture

The master architecture proposed introduces a fully hierarchical, yet distributed control approach. In this architecture, all field related control commands and data exchanges with substation or field control devices are guided through SCADA communications. This approach also recognizes the fact that peer-to-peer communications among field devices can be implemented through field area networks, using OpenFMB or any other standardized open communication schemes.

Complex applications have different control requirements and may need to utilize higher speed of communications and more granular measurements (larger bandwidth) in order to react to fast dynamic events and to apply corrective measures. Such controls may need to be implemented in the field closer to the end devices rather than at a centralized control center for superior performance. However, the command of actions should be supervised by a higher level controller with overriding capability. The main reason for incorporating this approach is the fact that localized controllers may not utilize system wide information to evaluate impact of their local actions on the rest of the system. The supervisory controller can determine any corrective and coordinating response to maintain the service quality in all areas.

Some exceptions in the aforementioned approach is handling of the AMI data and revenue meters at customer sites. Because of the level of investment in AMI, the existence and utilization of a parallel communication path is considered acceptable, with the condition that ultimately AMI data is populated in the PI Historian as the centralized database for all platforms. In addition, some investment is required to enhance the frequency and amount of data collection from the AMI system in support of load estimation algorithm as part of SCADA system and other applications.

The activities associated with market participation of certain DERs and dispatch of those resources (DSO and Aggregators) that are directly under the agreement with CAISO are implemented through a different communication platform. The communication system and data exchange associated with these resources need to meet certain technical requirements and the security compliance, subject to the approval of CAISO and regulatory agencies (NERC and FERC) that can become completely outside of the scope of distribution systems.

New requirements at the component layer will also roll up through the SGAM business, functional, information, and communications layers.

2.5.1.2 Future use cases

The new architecture for SDGE is driven by future use cases associated with DER integration into distribution operations, and how the use cases will be accommodated at the business, functional, information, communications, and component layers. The new architecture should also address gaps that have been identified, to improve overall business processes and functions.

2.5.1.3 Changes to SDG&E business processes or functions

With the proliferation of DER devices in the Distribution domain, the requirement for a Distribution System Operator (DSO) will emerge. DSO will function primarily in the Market zone, with interfaces at the business layer. While the need for DSO services at SDG&E may be undefined at this point, it may need to be accounted in the target reference architecture.

In addition functional responsibilities may need to be realigned among business units in some cases to fill gaps identified in the baseline architecture analysis, as well as accommodate new functions driven by the identified use cases.

For the most part, the SDG&E baseline architecture is reusable, but with some modifications described in the following sections.

2.5.2 Business layer

The present baseline business architecture and relevant organizations appear to be adequate for the target architecture. Thus the SGAM business layer is unchanged and is not shown again. Within the SDG&E organization, business units exist that already become involved in DER control, and market services. It may be a matter of redefining job responsibilities to cover new functions regarding DER at the feeder level, DSO services for DER as the need develops, and streamlining multiple accountability/responsibility assignments as previously discussed.

2.5.3 Functional layer

Figure 2-7 provides a view of the baseline business function categories and business functions, with notations where expansion or modifications of functions may be performed.

Data analytics and data management may be combined into common platforms to serve multiple business units to gain a better economy of scale. Business Unit to oversee each platform is subject to further review.

Alarm processing functions may not be easily consolidated. Each business unit has responsibility for reacting to their own set of alarms, and have specialized resources to address issues. However a common operations center could also have some economies. The feasibility of consolidating alarm processes would be subject to further review.

2.5.4 Information layer

Use of standards at the information layer will facilitate interoperability among different vendor choices and systems, helping to lower SDG&E operating costs by not having special interfaces to support proprietary or redundant systems.

For Enterprise, Data clients/interface points: SDG&E currently uses an Enterprise Service Bus, and MultiSpeak. At the Enterprise/Systems zone, IEC 61968 can be implemented to support the CIM model. Part 1 of IEC 61968 is the first in a series that, taken as a whole, defines interfaces to support the inter-application integration of utility enterprise systems including metering, distribution and related functions. IEC 61968 also has provisions to create a CIM profile to implement MultiSpeak functionality. IEC 61968 also reaches into the Operations zone, with harmonization efforts with CIM/61850 for distribution grid management.

At the market zone, standards include OASIS, and IEC 62325. The actual choice of SDG&E for implementation may be influenced by SDG&E's direction and position on how to implement market services for transmission as well as distribution in the future. OASIS is included in SGIP's catalog of standards, IEC 62325 is not.

Below the Enterprise zone, and in the Distribution and DER domains, the IEC 61850 suite of standards provides some definitions for object models that could be used to define information exchanges. In the customer premise domain there are several meter related standards included in the SGIP catalog of standards that help define information to be exchanged between the utility, customer, and third party provider. The proposed architecture is summarized in Figure 2-8 below.

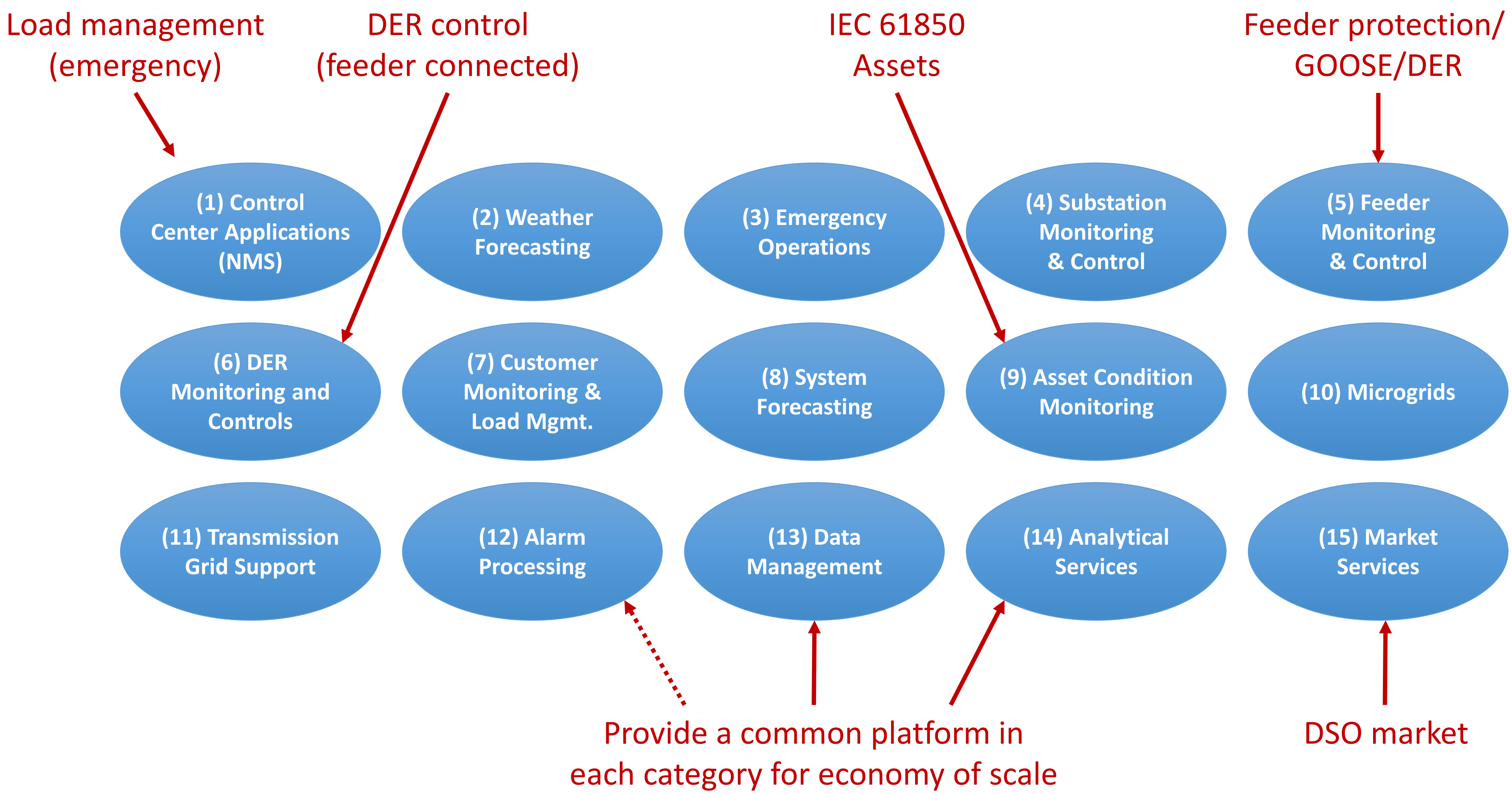

Figure 2-7. Business function categories and functions, augmented with target functions

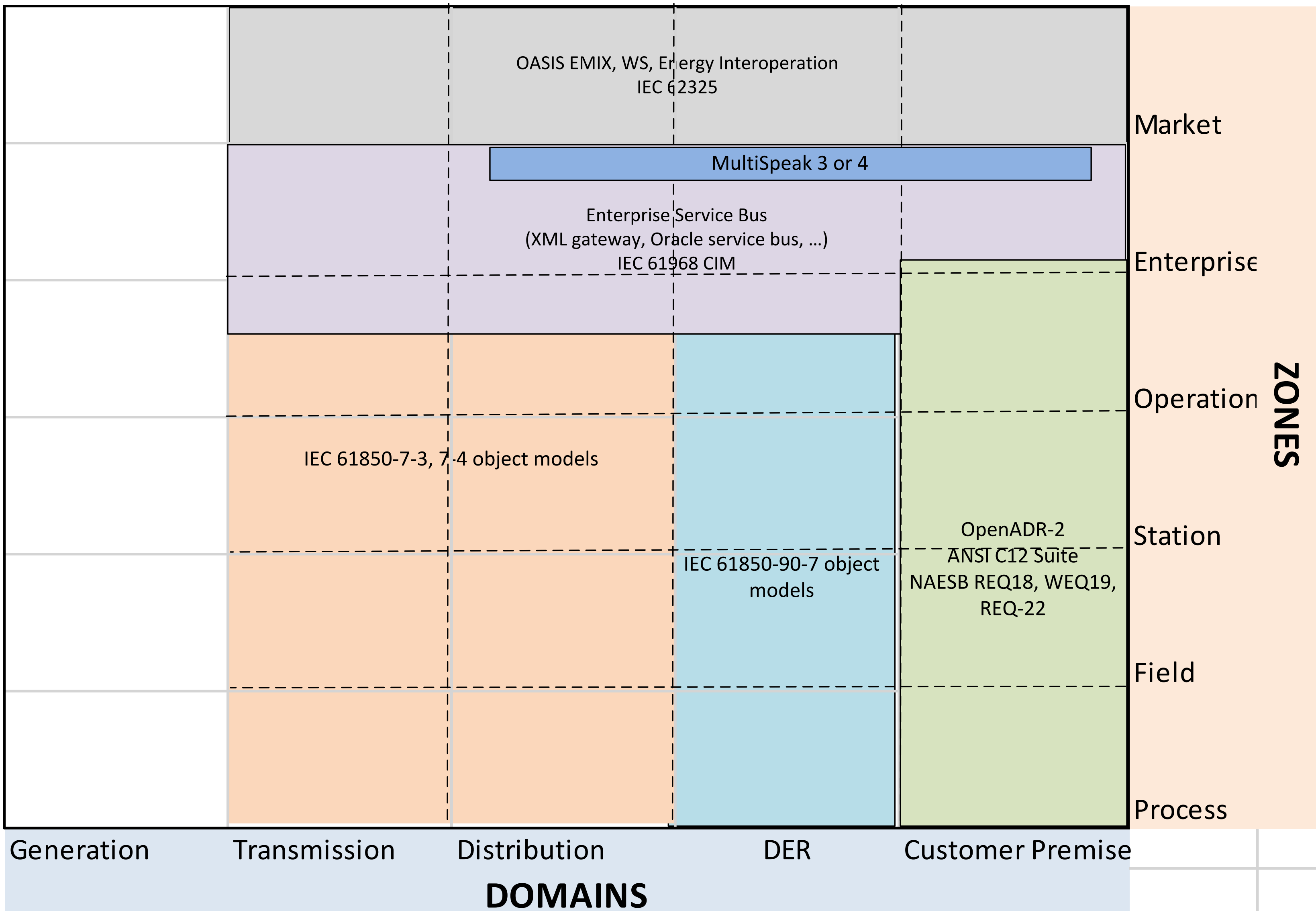

Figure 2-8. Proposed information layer architecture

2.5.5 Communications layer

As noted earlier, the communications layer can be defined as having two parts:

1. The communications applications layer
2. The communications transport layer

2.5.5.1 Communications applications architecture

The key platforms of IEC 61850 and NAESB RMQ.26 are overlaid on the previous baseline communications applications layer to show their integration with and inter-operability to the various SDG&E interfaces. This is depicted Figure 2-9.

For Enterprise, Data clients/interface points: The reference architecture for the information layer, overlaps somewhat with the communications applications layer, in that with the reference standards, functions are provided to support both layers, which will ride over the communications transport layer. At the Enterprise/Systems zone, IEC 61968 can be implemented to support the CIM model. Part 1 of IEC 61968 is the first in a series that, taken as a whole, defines interfaces to support the inter-application integration of utility enterprise systems including metering, distribution and related functions. IEC 91698 also has provisions to create a CIM profile to implement MultiSpeak functionality. IEC 91698 also reaches into the Operations zone, with harmonization efforts with CIM/61850 for distribution grid management.

At the market zone, standards include OASIS, and IEC 62325. The actual choice of SDG&E for implementation may be influenced by SDG&E's direction and position on how to implement market services for transmission as well as distribution in the future. OASIS is included in SGIP's catalog of standards, IEC 62325 is not.

At the operations layer and below, IEC 61850 provides a ubiquitous platform to provide interoperable communications among components in the various zones, with mapping to most of the SDG&E communications applications protocols already in service including: DNP3, C37.118, MultiSpeak 3, IEC 60870-101.

However, certain communications application protocols is use by SDG&E are legacy, and interfaces to a standardized IEC-61850 may require further migration considerations:

- MODBUS (field zone)
- SCOM (field zone)
- SEL Mirrored bit (substation zone)
- Other vendor proprietary (substation zone)
- PQDIF (substation zone)
- Open Systems Interfaces (Operations zone)

- In the customer premise domain, the field area network is a vendor-specific product that is based on open standards, but may also require special interface considerations in a standardized reference architecture.

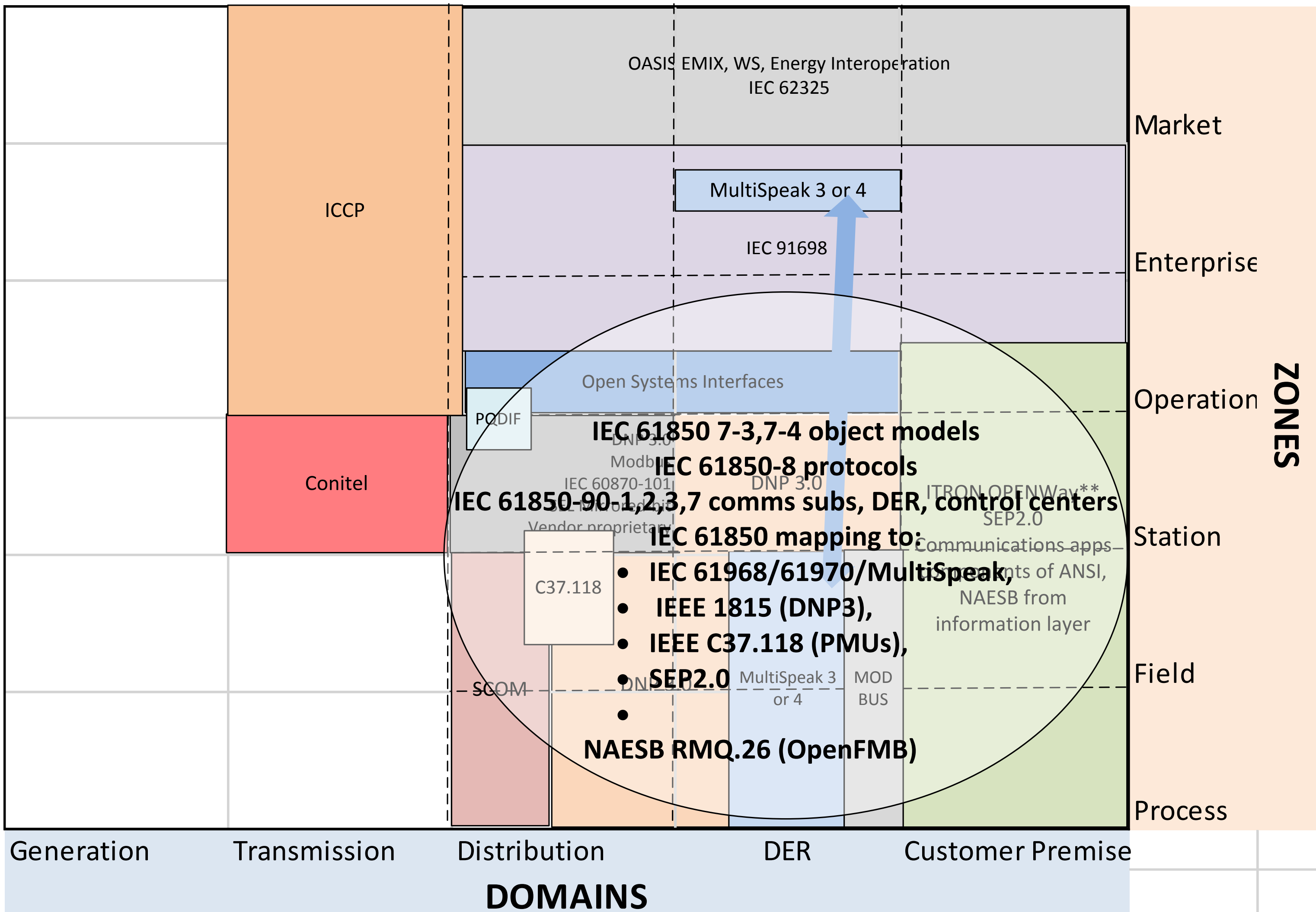

Figure 2-9. Proposed communications applications layer

- The implementation of NAESB RMQ 26 (OpenFMB) is also included in the reference communications applications architecture. The OpenFMB will interface with various power system components that communicate using various protocols such as DNP3.0, Modbus, IEC 61860, SEP 2.0, XMPP, CoAP and others. Open FMB aims to replace multiple proprietary systems with an Open system based on the Internet protocol, and may well be a complement to IEC 61850 field implementations.

2.5.5.2 Communications transport architecture

Figure 2-10 shows the target communications transport architecture.

For the target communications transport layer, the goal is to migrate from legacy time-division-multiplexed (TDM) based technologies such as SONET or T1, to TCP/IP based transport that utilize link layer technologies such as Ethernet or MPLS.

In the Operation and Enterprise zones, TCP/IP is already the prevalent communications wide area networks between sites, and Ethernet based local area networks within a site. IP version 4 is in operation. SDG&E Plans to migrate to IP version 6 is unknown at this time, but IPv4 is expected to be prevalent in the industry for many more years. In the market zone, migration from legacy TDM to TCP/IP should occur.

For distribution and DER at the station, field, and process zones, legacy serial connections exist, as well as some IP based communications. Point-to-point radios such as low capacity microwave radio, or point-to-multipoint low speed MAS radios also exist at these levels, primarily not for direct customer interfaces. The RF mesh network associated with vendor-specific field area network has been established to connectivity with customer applications. Legacy serial connections should eventually migrate to Ethernet/IP based communications transport.

2.5.6 Component layer

To achieve the objectives of eliminating areas of parallel control, allowing a more distributed control architecture, and avoiding proprietary communications protocols, the proposed component architecture introduces a fully hierarchical, yet distributed control approach. In this architecture, all field related control commands and data exchanges with substation or field control devices are guided through SCADA communications. This approach also recognizes the fact that peer-to-peer communications among field devices can be implemented through field area networks, using OpenFMB or any other standardized open communication schemes.

The activities associated with market participation of certain DERs and dispatch of those resources (DSO and Aggregators) that are directly under the agreement with CAISO are implemented through a different communication platform. The communication system and data exchange associated with these resources need to meet certain technical requirements and the security compliance, subject to the approval of CAISO and regulatory agencies (NERC and FERC) that can become completely outside of the scope of distribution systems.

2.5.7 Representative security architecture model

The *Smart Grid Reference Architecture* document shows the Security Logical Model. For further discussion on the model, please refer to the referenced document.

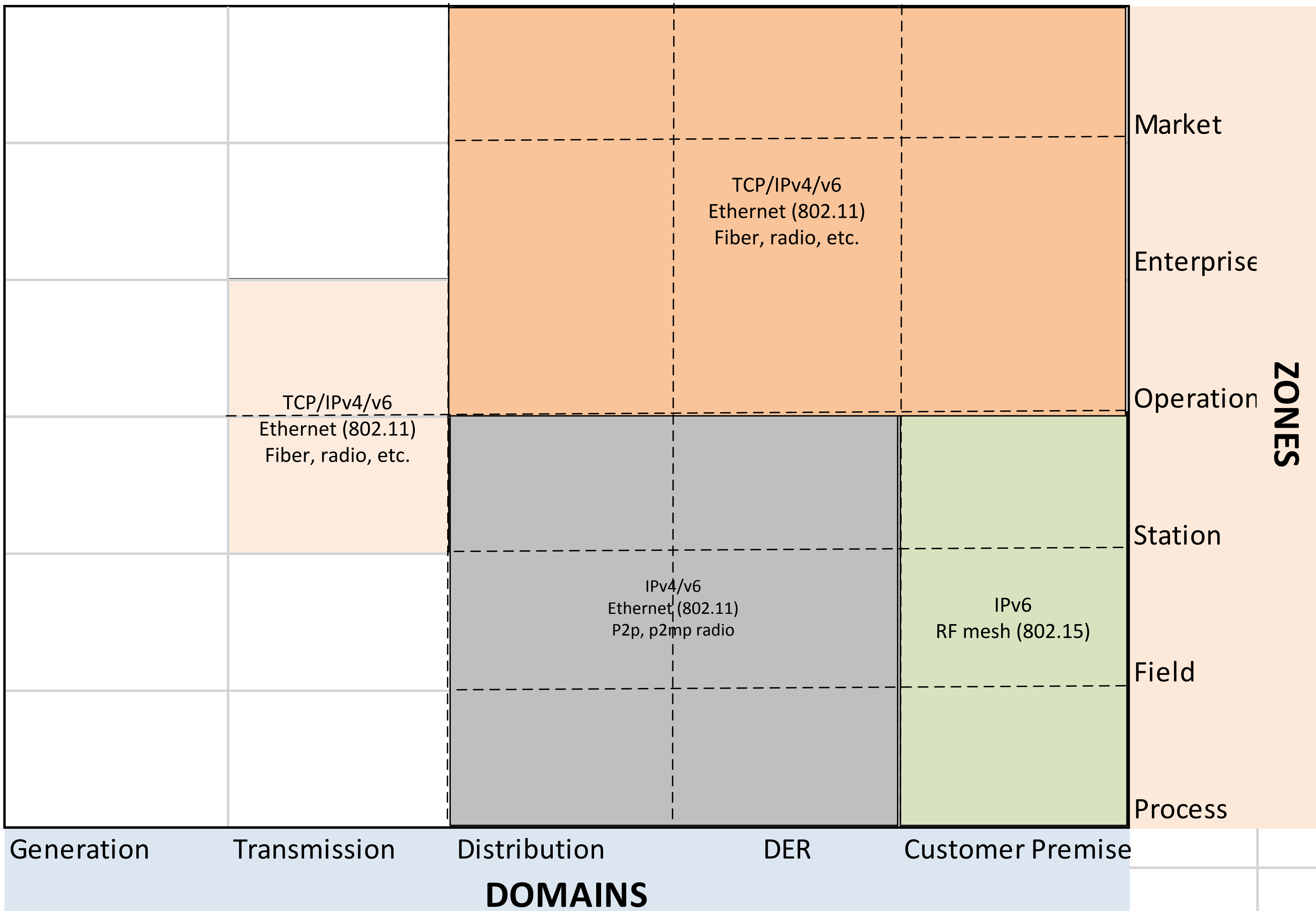

Figure 2-10. Proposed communications transport layer

The Security Services Stack Model has several parts:

- Support services – services that may come from another portion or tier of the architecture but are necessary to support the services in the tier being described
- Foundation services – key security services, generally needed throughout the architecture which other services depend or expand upon
- Core services – the primary security architecture service stack
- Integration services – services specifically providing integration between security and other architectural tiers or business systems

The Security Synergy Model illustrates how security services can be shared to meet various Smart Grid security requirements.

SDG&E cyber security policies may be reviewed to determine how the recommended target architecture will affect baseline security policies.

2.5.8 Issues or problems addressed by the proposed architecture

This section describes the key gaps between the current (as-is) and proposed (to-be) reference architectures. This difference, or delta, defines the scope of work that needs to be undertaken in order to transition from the current to the proposed architecture. This scope is thus the scope of the program(s) or project(s) that need to be completed in order to reach the proposed business architecture. Table 2-11 presents a summary of key gaps between baseline and proposed architectures.

Table 2-11. Summary of key gaps between baseline and proposed architectures

Ref ID.	Baseline Architecture Issue	Impact	How addressed by proposed architecture
SGAM Component Layer			
C1	SCADA controls are centralized at the control center: As the capabilities of the communications infrastructure advances, additional intelligence will need to be deployed closer to the customer premise, allowing proactive decisions to be made locally to avoid or minimize outages, while informing the utility systems and operators of the local actions taken. Migration to this architecture will impact all SGAM layers, including present business processes Control of DER assets is not coordinated via SCADA. Direct control is accomplished via vendor proprietary dedicated links. However, the DER asset owners must coordinate with Distribution Operations SCADA prior to implementing any controls	High	Architecture changes to eliminate SCADA areas of parallel control as described in target component architecture, and allow for a more distributed component architecture. Fundamentally, all controller should utilize the same source of operational data and should have access to the same system models The concept of unifying data sharing and information accessibility across all control platforms also requires standardization of the data exchange mechanism and, more specifically, avoiding proprietary communication protocols.
C2	The Customer domain appears to be independently operated with no interoperability with other domains. Any data	Med	Because of the level of investment in AMI, the existence and utilization of a parallel communication path is considered

Ref ID.	Baseline Architecture Issue	Impact	How addressed by proposed architecture
	exchange occurs at the Enterprise level, when may impede the implementation of timely actions to improve service.		acceptable, with the condition that ultimately AMI data is populated in the PI Historian as the centralized database for all platforms. In addition, some investment is required to enhance the frequency and amount of data collection from the AMI system in support of load estimation algorithm as part of SCADA system and other applications. Standardization at the Enterprise zone through the use of CIM, MultiSpeak, and other standards will facilitate the data exchange with other layers and zones.
SGAM Communications Transport Layer			
CT1	Only a fraction of links are capable of high-speed communications (typically those to the newer generation SA/SA equipped substations	Med	This issue will only be solved over time, as future architectures are deployed based on their cost/benefit to the SDG&E business process. However the target architecture does position future implementation to be consistent with interoperable standards, using state-of-the art technology.
SGAM Communications Applications Layer			
CA1	Specific protocol to support distribution operations at market level is absent. Not currently a widely utilized application. However, as utilities migrate to a distribution systems operator (DSO) role, communications among market entities (third party service providers, DER aggregators, CAISO, other utilities) will be important.	Med	Standards have been identified to support market operations that cover both the information and communications applications layers. Development and implementation of these standards will depend on the role of SDG&E in future distribution market services.
CA2	Some legacy protocols still in use such as SCOM, MODBUS; there is a variety of legacy protocols from the process to the Operations levels across all domains. Each protocol requires a certain amount of maintenance and upkeep. There is no clear path of interoperability between the protocols, without having to go to the Enterprise zone to allow a common interface between systems. The component layer confirms that there are no direct connections from the Customer domain to allow interoperable processes to occur	Med	The legacy protocols in use at the substation and field levels will not be replaced overnight. However the new reference architecture provides a path for interoperable protocols and “adapters” (i.e., through OpenFMB, IEC 61850) to possibly accommodate the legacy protocols, or continue supporting interfaces at the Enterprise zone through more efficient standardized processes.
SGAM Information Layer			
I1	In the SGAM context, this layer is virtually	High	The reference architecture defines

Ref ID.	Baseline Architecture Issue	Impact	How addressed by proposed architecture
	non-existent in the SDG&E environment, from the operations layer to the process layer, across all domains. Proprietary methods of defining data information requirements exist with "siloed" applications, and no set of standards. Most of the information formats are defaulted to the communications applications protocols. This is a key gap; to support the multiple proprietary methods results in an increased cost of operations.		standards for the information layer that adapt to both the information and communications applications layers. With the standardized approach, the siloed data applications can be harmonized for greater use and distribution across the SDG&E organization.
SGAM Functional/Business Layers			
F1	There are independent functions at the market level, for specific needs in Customer programs and Electric & Fuel procurement. There appears to be gaps in this area to support future Distribution operations requirements	Med	The market services gap is addressed in CA1 above, pertaining to industry standards to facilitate the process. A RACI analysis is required to identify SDG&E organizational units that would be anticipated to participate in distribution market requirements.
F2	Certain functions appear to have multiple business units who are assigned responsibility or accountability, such as: Storm and fire operations Feeder Control Asset condition based monitoring Load management (emergency) Substation monitoring, control Some of these multiple assignments can be attributed to the varying requirements of the functions: based on certain operating conditions: at times a certain group may be responsible for the function until a normal operational state is returned; under other conditions, another group may have the responsibility.	Low	This is more of an organizational characteristic than an issue. Responsibilities and accountabilities have been documented in a RACI analysis, and included as part of the SGAM business and functional layers.
F3	Functions of alarm processing, data management, and analytical services appear to be performed independently by the groups in relation to the alarms, data, and analytics for which the group has responsibility for, or most interest in. Thus these functions may be replicated across several organizations.	High	Standardization through a reference architecture facilitates the use of common platforms across multiple business units. Data management and analytical services may benefit from the common platform approach to serve multiple organizations, from a cost and efficiency standpoint. Alarm processing may also benefit through a common network management platform, however several organizations have their own set of alarms for which they are responsible, that may not have commonality with other groups (i.e., security alarms, vs.

Ref ID.	Baseline Architecture Issue	Impact	How addressed by proposed architecture
			equipment malfunction alarms). A common organization or business process to service all the alarms would be subject to further review.
F4	Reconciliation of proposed use cases with functional and business processes. For phase 3 testing, a certain number of use cases are identified for testing at the ITF. These use cases should also be reviewed to determine their impact on existing functions, groups, and RACI assignments for Distribution Operations, to identify any changes that may be required from existing processes	High	Target Business and Functional layers have identified the new requirements associated with the future DER integration requirements that the use cases represent, and sorted out roles and responsibilities for the functions through a RACI analysis. Existing SDG&E organizational structure appears adequate to accommodate new roles, it is just a matter of redefining responsibilities to align with Target component layer, and reduced parallel operation of components.
SGAM Business Layer			
B1	The Distribution, DER, and Customer domains appear to be independently managed with few cross-domain services. This may impede efficiency of operations	Med	As a result of the Target architectures developed and standardized at the other layers as described above, this gap is inherently incorporated and addressed.

2.5.9 Summary and roadmap for proposed architecture implementation

Implementation of the target architecture should be performed as the opportunity arises from DER growth, market development, and general legacy component replacements. A 10-year implementation time frame is expected for near full deployment. The considerations that would be necessary to work toward the eventual migration to the target architecture is described in the previous sections. The general activities that would be required are summarized below in the context of SGAM layers:

- **Component layer***:* take into account distributed control recommendations, primarily more pro-active direct SCADA control incorporating DERMS, field devices, to mitigate parallel operations. DSO server to negotiate DER integration and control.
- **Communications applications layer**: more use of IEC 61850 for transport and applications interfaces; utilize adapters to interface with other standards protocols such as DNP3, MultiSpeak, C37.118, etc. Interfaces to legacy protocols such as SCOM are to be determined. To support use cases, IEC 61850-8-1 (GOOSE), IEC 61850-7-2, to be implemented
- **Information layer**: Implement standardized approach to information exchange utilizing IEC 61850, IEC 61968/61970, etc. This would include document/drawing files, XML files, IEC 61850-7-3, 7-4 Object Models, IEC 61850-6 Engineering, especially to support use cases.
- **Functional layer**: Changes driven by more direct SCADA control, new functions from DER related use cases: Modification of certain existing Distribution Operations functions (from baseline functional layer) taking into account more prevalent use of DER integration at the feeder level:
  - Asset Condition-based Monitoring

        - Designing, Engineering, building, commissioning, and maintaining IEC 61850 compliant protection and automation systems
        - Maintenance testing of IEC 61850 compliant relay/IED
    - Feeder Protection
        - Breaker failure scheme with GOOSE messaging
        - Automatic Transfer scheme using GOOSE messages
        - Protection Coordination with IEC 61850 (including anti-islanding protection of DERs, reclosing/relaying operation, enhanced operation of feeder protection
    - DER Control (Feeder connected)[NOTE: this is in addition to existing Distribution Operations function of DER control(generation/storage)
        - Remotely change control mode of DER (IEC 61850)
        - Using multiple large scale DERs, correct feeder power factor/improve feeder voltage; coordinated use of ride-through capabilities to enhance system performance under network faults and/or transient disturbances
    - Load management (emergency)
        - Effective utilization of DER contributions to offset customer loads

- **Business layer:** defined roles and responsibilities relating to new functions from DER use cases, potential other modifications based on gaps discovered during baseline RACI analysis:
    - Definition of market services including DSO responsibilities
    - Siloed operations in alarm processing, data management, data analytics
    - For a single function, assignments of accountability or responsibility to multiple entities

The present baseline business architecture and relevant organizations appear to be adequate for the target architecture. Within the SDG&E organization, business units that already exist become involved in DER control, and market services. It may be a matter of redefining job responsibilities to cover new functions at the feeder level, DSO services for DER as the need developed, and streamlining multiple accountability/responsibility assignments as previously discussed.

Any legacy or proprietary protocols or information models may need to be transitioned to a more standards based approach over time to realize the full economies and advantages of a standardized reference architecture.

2.5.10 Implementation planning

Generally, in utilities, a change of technology, architecture, or processes is a multi-year process, being driven by cost/benefit feasibility, as well as regulatory constraints. Many types of utility assets (i.e., substations, field devices, etc.) are designed to last 20-30, or even 40 years or more, and thus waiting to make an end of asset life replacement can be a challenge.

Key drivers for change may include: level of DER penetration and growth, where an asset stands in its life cycle, or benefit/costs analysis to evaluate if there are other more cost-effective ways to support the present mode of operation of the business of energy delivery.

Potential architecture changes are related to the expected increase of DER integration and its impact on Distribution Operations, functionally and organizationally. Adoption of industry standards may also impact the organization through the requirement for additional tools, software, or systems. Some general milestones are listed below to provide a high-level roadmap for the architecture migration. These are notional time frames, subject to refining based on SDG&E infrastructure requirements and capabilities.

2.5.10.1 Phase 2 planning: First three years

1. *Review Business Processes and Functions as defined by the baseline RACI analysis*

   Review the gaps identified in the baseline RACI matrix to determine if it is feasible to improve processes: Redundant processes identified such as data analytics, data management, and alarm processing to determine if common platforms for each function may be feasible. This could possibly be used as a "springboard" for standards implementation.

   Review and assess the multiple "A" or "R" assignments to confirm their validity, or identify reasons for the multiple assignments. (Some can be attributed to the varying requirements of the functions based on certain operating conditions).
2. *Perform DER integration forecast:* The speed of DER integration into the SDG&E system will be a pacing factor for what needs to be done, and how fast it should be done. Thus DER Integration could be a catalyst in the target architecture implementation.
3. *Asset age inventory:* review relevant distribution assets to determine if there are any prime candidates due for replacement that can be used as a catalyst for architecture upgrade
4. *Review and develop plan for SGAM component layer changes to meet target:* develop a plan for implementing changes at the component layer to eliminate areas of parallel control, establish a more distributed operations as described in the target architecture.
   a. Based on component changes, develop plan for related requirements at the communications, information, functional, and business process layers
5. *Perform a communications review* to determine the feasibility of implementing more high-speed networks

2.5.10.2 Phase 3 implementation: years 4 through 10

1. Based on DER integration forecast develop action plan to support it:
   a. Identify and develop a plan for SDG&E's role in distribution market operations. In conjunction with this, identify relevant market standards and protocols that would support the market operations
   b. Start with "low hanging fruit": Identify areas of higher growth, and the adequacy of the current infrastructure to support it, and how IEC 61850 may be implemented to meet requirements.
2. Review requirements and implement changes to support IEC 61850 implementation, including:
   a. Organizationally to support use cases: groups responsibilities, skills required
   b. requirement for additional tools, software, or systems
3. Review feasibility to support Enterprise standards implementation including IEC 61968, MultiSpeak, etc., including:
   a. Organizationally to support use cases: groups responsibilities, skills required
   b. requirement for additional tools, software, or systems
4. Based on planned implementations, develop and implement a cyber security plan for a standardized approach to support the target architecture.

2.5.10.3 Legacy devices

Within the present SDG&E architecture, there are legacy devices that utilize legacy communications protocols and networks that may need to be supported until such time it becomes cost-effective to replace them. However, there are dual platform devices offered by some vendors that could support both the legacy and latest standards, utilizing adapters or other interface schemes, that could facilitate the migration and reduce the risk of the stand-alone legacy devices.

Implementation of new architecture may be impeded if new and legacy technologies cannot co-exist.

2.6 Phase 3 – Task 5: Design test system

While the primary focus of the project was on distribution automation (DA) and DER integration, two other areas were included; distribution substation automation and non-functional activities. The complex interaction between the protection and control elements in the substation and along the feeder made it important to include substation equipment in the use cases and testing[11]. Non-functional activities involve those associated with the deployment and maintenance of IEDs, regardless of location, and because IEC 61850 results in some specific challenges, this was identified as a third focus area of testing.

A single line diagram of the test system is illustrated in Figure 2-11 below. The test system was selected in a way that all the aforementioned three areas could be tested. An actual substation was selected as the basis for the model and additional substation and feeder-based DER devices were added, and/or sizes increased to exacerbate certain use case conditions to better illustrate the problems and efficacy of the solutions.

While much of the system was modelled in the Real Time Digital Simulator (RTDS), extensive use was made of actual hardware devices – both IEDs and DER. These are indicated in yellow in the diagram above. IEDs included protective relays, Remote Terminal Units (RTU), Load Tap Changer (LTC), meters and Voltage Regulators (VR). DER included a Battery Energy Storage System (BESS) and a Smart Inverter/Photovoltaic array.

Figure 2-12 below shows the system configuration and how the various physical devices were interconnected. One of the purported benefits of the IEC 61850 standard is interoperability between the products of different vendors, and the test system was constructed using equipment from multiple vendors to test this premise. Accordingly, IEC 61850 equipment from three different vendors were procured to fulfill various protection and control functions.

[11] It is worthwhile noting that a separate EPIC project was specifically tasked with examining the deployment of IEC 61850 in a substation. Care was taken not to duplicate any of the work performed under the auspices of that project.

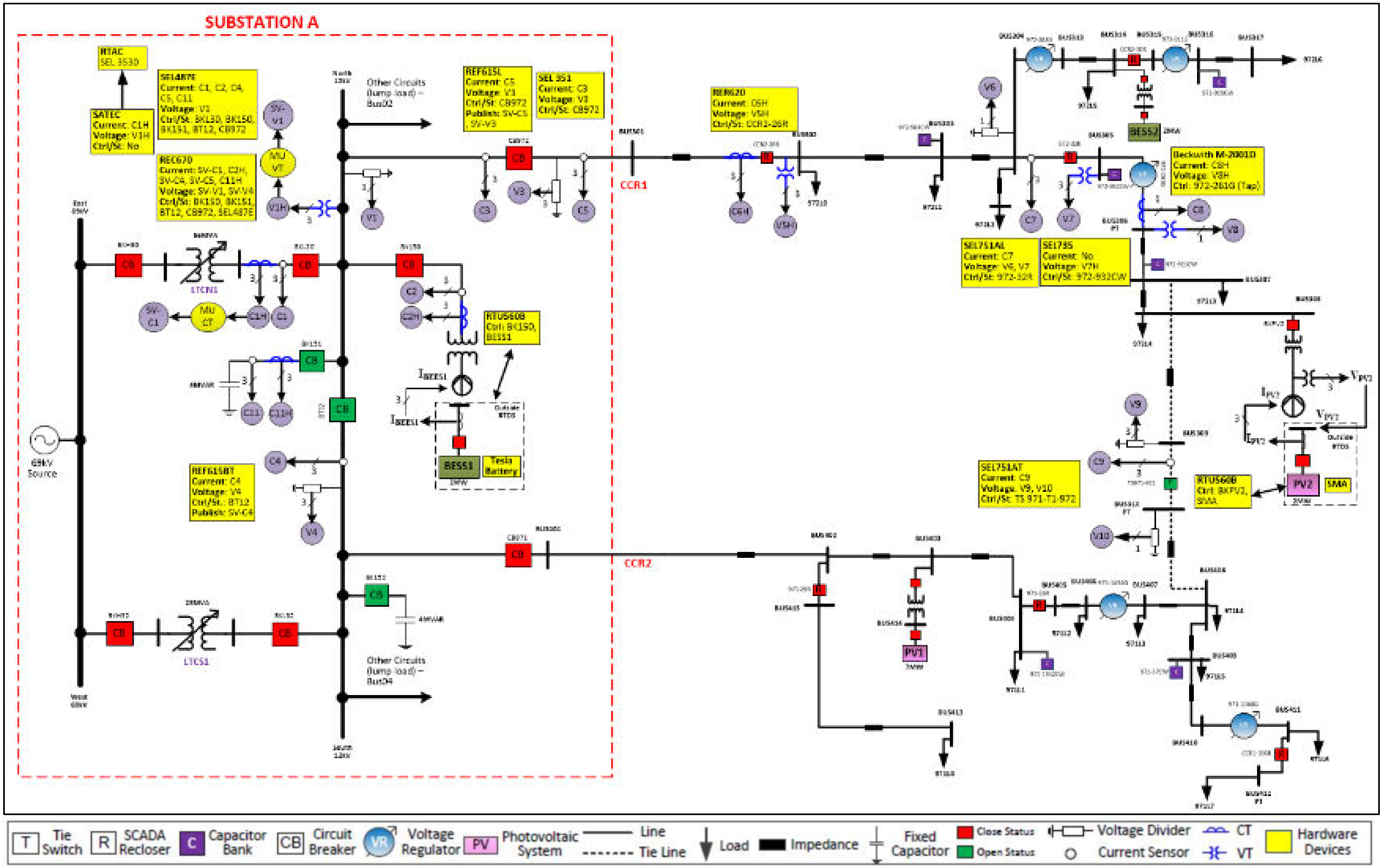

Figure 2-11. Single Line Diagram of the test system showing key elements.

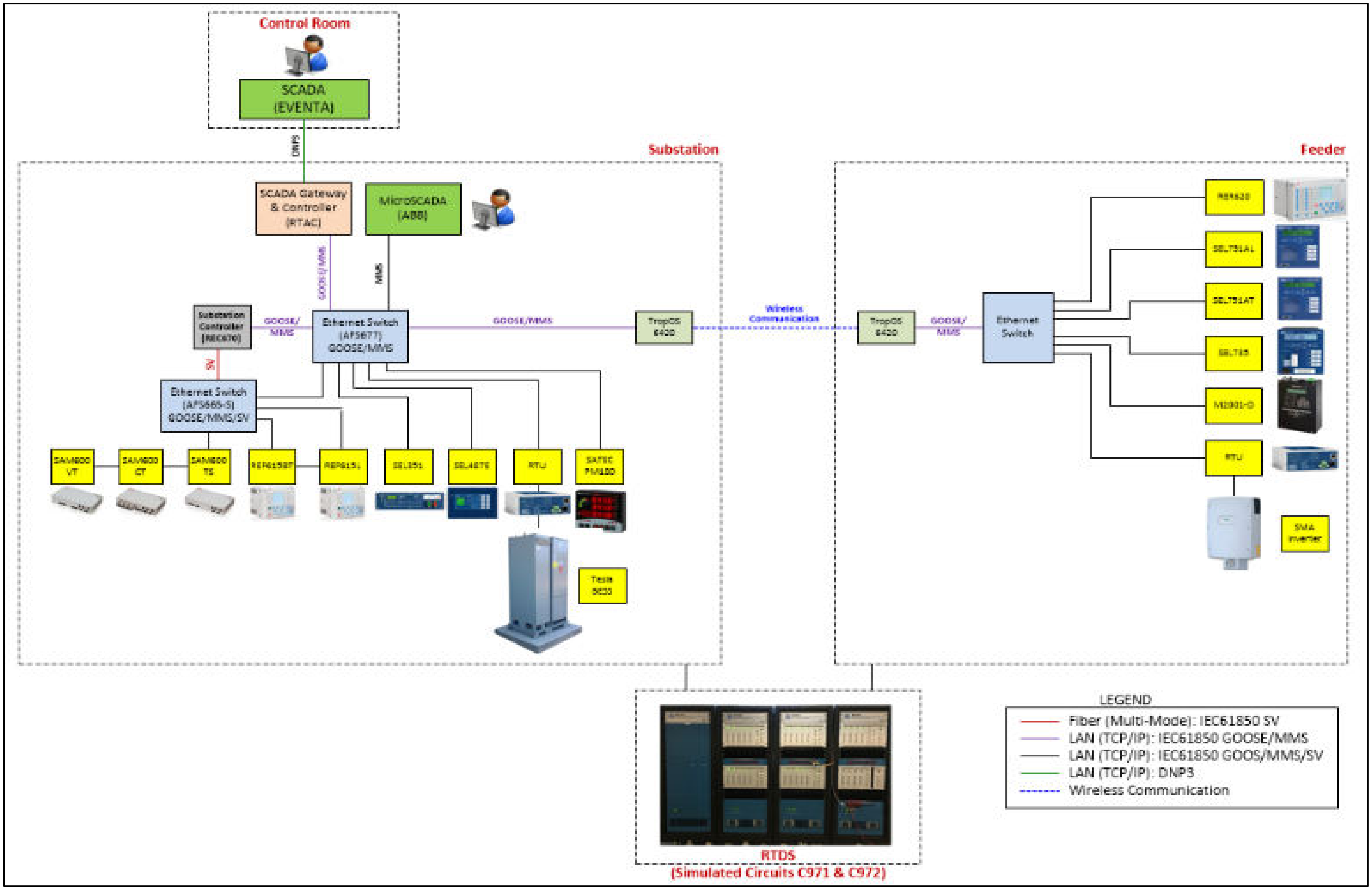

Figure 2-12. System configuration of actual IEDs showing interconnections.

To fully exercise the capabilities of the IEC 61850 communications, the substation communication topology employed both a Station Bus and a Process Bus.

- The IEC 61850-8-1 Station Bus was used by the various IEDs to exchange data among themselves using the peer-to-peer capabilities of IEC 61850, as well as for control commands from the different devices in the architecture capable of issuing these.
- The IEC 61850-9-2 Process Bus was used to interconnect merging units with protection and control IEDs and provide sample values from RTDS-simulated Current Transformers (CT) and Potential Transformers (PT).

The downstream feeder-based IEDs were connected wirelessly to the substation equipment via an extension of the Station Bus using a high-speed wireless network.

2.6.1 System components

Table 2-12 that follows lists the primary system components, the products selected and the role of each element. Note that the selection of equipment does not imply a specific preference for that vendor or that product, nor does it confer any endorsement for their use.

Table 2-12. System components and their role.

Device	Role
Simulated SCADA control center	This device provided a platform from where the control and monitoring of substation and feeder assets could be performed. The Simulated control center interfaced with the Substation Data Concentrator via the DNP 3.0 protocol.
Substation Gateway	This device acted as a conduit between the SCADA control center and the rest of the equipment in the configuration. It communicated upstream to the SCADA control center via DNP 3.0 and downstream to other system components via the IEC 61850 Station Bus. The original intent was to use both MMS and GOOSE communication services, but the final configuration only employed GOOSE for reasons to be discussed in more detail in the Recommendations section.
Substation HMI	In addition to providing local control and monitoring functionality during system testing, the Substation HMI provided event recording and alarming. It also hosted the IED configuration software used to build and maintain the system setup and several engineering and diagnostic tools used to facilitate testing and troubleshooting. It communicated to both substation and feeder devices via the MMS communication service.
Network firewall	This device was intended to provide a secure access point for remote maintenance activities such as retrieving monitoring data or to perform remote diagnostics. The functionality to be tested in the use cases that were eventually selected did not require the use of the firewall and it was not deployed in the final system.
Time Server	This device was a dedicated time server providing high accuracy time synchronization of

Device	Role
	the entire digital substation automation system. It used a combination of services to time synchronization the various system components, including: • IEEE1588 time sync protocol • SNTP • IRIG-B
IEC 61850 Station bus / Ethernet Switch	This device provided the Station bus that the Substation Gateway, Substation HMI, Time Server, and most of the substation and feeder IEDs connected to.
Wireless gateway and router	Communications between the substation and feeder equipment was accomplished wirelessly using a high-speed meshed wireless network.
IEC 61850 Gateway for legacy device integration	As will be discussed in a section that follows, the project was unable to source any DER controllers with native support for IEC 61850. It was therefore necessary to integrate these legacy devices into the IEC 61850 network using a protocol converter capable of communicating to the DER controllers via the supported protocol – which happened to be Modbus in both cases.
Protection and control devices	To test interoperability, different IED types from a variety of vendors were used. The IED types included protective relays, voltage regulators, meters, remote terminal units, and cap bank controllers. • Substation P&C devices: Merging units, bus tie protection, feeder protection, power quality meter, and substation controller • Feeder P&C devices: Recloser (CCR2-26R and CCR2-32R), voltage regulator (CCR2-261G), cap bank controller (CCR2-932CW), and feeder tie controller (TSCCR1-CCR2) Both MMS and GOOSE communication services were used to integrate these into the system and in data exchange between the devices.
Stand-alone merging units	Utilizing modular stand-alone merging units and the IEC 61850 Process bus, conventional CTs and PTs were integrated into the configuration for use by the Protection and Control Devices.
RTDS	A real-time digital simulator (RTDS) was used to represent the 12kV distribution study system with all major protection and control (P&C) assets modeled.
DER Devices	Selected power devices: two inverters were used for the power hardware-in-the-loop (PHIL) testing in this project. These inverters were interfaced with the power system (RTDS) through a Remote Terminal Unit unit, which converted IEC 61850 GOOSE (Generic Object-Oriented Substation Event) messages to the protocol supported by the inverter (Modbus).

2.6.2 Use cases

Use cases were developed to test the application of the IEC 61850 standard in the three separate areas defined earlier, i.e., distribution automation (DA) and DER integration, substation automation and non-functional activities. An additional three use cases were defined to compare the performance of IEC 61850 against existing and emerging protocol standard (DNP 3.0 and OpenFMB). Table 2-13 below lists the uses cases and identifies which area each addresses.

Table 2-13. Use cases developed for Phase 3 testing

Use Case	Name	Protocol	Non Functional	Substation Automation	DA and DER Integration
1	Full Lifecycle Asset Provisioning	IEC 61850	☑		
2	Maintenance Testing		☑		
3	Breaker Failure Scheme			☑	
4	Automatic Transfer			☑	
5	Improved Protection Coordination			☑	
6	DER Control Mode Change				☑
7	Grid Support using DERs				☑
8	Emergency Load Management				☑
9	Dynamic Emergency Load Control and Management	IEC 61850 OpenFMB		☑	☑
10	Dynamic Circuit Load Management	IEC 61850 DNP 3.0		☑	☑
11	Volt-var control	OpenFMB		☑	☑

Table 2-14 that follows provides additional details on each of the IEC 61850-specific use cases.

Table 2-14. IEC 61850-specific use case description

Use Case	Title	Description
1	Lifecycle Asset Provisioning	The utilization of the IEC 61850 standard in protection and automation systems requires changes to the design, engineering, building, commissioning and maintenance procedures used today. The IEC 61850 engineering process is based on the use and exchange of XML-based description of system components, system configurations and capabilities. During the lifecycle of an automation and protection system, changes, replacements, extensions and reductions of the system are typical scenarios that require special consideration. The objective of this use case was to demonstrate the engineering process to: • Create IEC 61850 system configuration files including: ▪ MMS mapping and HMI integration ▪ Peer to peer (GOOSE) communication between IEDs ▪ Sample values assignments (process bus) • Facilitate documentation of the system design and implementation, • Simplify the process of updating and reconfiguring an existing system, • Adding, removing, or replacing single components (IED and/or DER) in the existing system
2	Maintenance test	For maintenance purposes, regular time-based or condition-based testing is performed on IEDs to confirm their proper operation. To do this, the test

Use Case	Title	Description
		engineer must isolate the IED under test from the system to avoid any undesired breaker operations during the maintenance testing process. In the case of conventional, non-IEC 61850, wire-connected systems, the test engineer opens test switches to perform maintenance tests. However, the situation is much different in the IEC 61850 environment, where the isolation of the relay/IED can be done through communications. The latest IEC 61850 standard defines a test mode and simulation features specifically to address this. This use case applied and verified the use of the test mode and simulation features to facilitate maintenance testing of relays/IEDs, as compared to a traditional wire-connected system. The objective of the use case was to investigate, test, and document the isolation and re-routing mechanism for GOOSE and process bus links. The main questions to be addressed included: • How can the IED read process bus data provided by a test set versus the actual merging unit information during the maintenance test? • How can a GOOSE link to any other device (for example breaker failure start) be interrupted during the maintenance test?
3	GOOSE Performance/Breaker Failure	With the use of IEC 61850 communications, copper wire interconnection between IEDs can be replaced by GOOSE message exchange to perform certain actions. An example is breaker failure signals. When a feeder circuit breaker fails to operate and isolate a fault, the feeder relay needs to send a breaker failure trip to the bus protection relay in order to isolate the bus from the faulty section. While the industry has extensive experience with the performance of this feature using a hard-wired scheme, the use of GOOSE messages to accomplish this function has not been widely reported upon. The objective of this use case was to contrast the performance of a GOOSE-message based breaker failure scheme with that of the conventional approach.
4	Automatic Load Switch	Automatic transfer schemes are used to maintain continuity of supply during the transfer of a bus from one power source to an alternate power source. A proper transfer system must be designed in such a way that it i) operates quickly and ii) prevents damages to loads connected to the transferred bus. In the events of losing one of the main in-feeds, e.g., due to an accidental breaker operation at the 69kV voltage level or a transformer fault, the dead bus can be energized and fed via the bus tie. Ideally, the outage of one of the main supply transformers can trigger a load transfer to the other in-feed. However, before the bus tie can be closed to complete the transfer, certain criteria must be checked to ensure safe and reliable load transfer. The criteria become more important in the presence of DERs in distribution circuits. The objective of this use case is to implement an automatic transfer scheme Using IEC 61850 GOOSE messages based on SDG&E practice and requirements. Circuit breaker positions, voltage phasor measurements, fault indications and synchronizing condition information are transmitted via IEC 61850 communication protocol and processed by the substation computer or a dedicated automation controller. Hot switch over (closed transition) and cold switch over (open transition) scenarios should be included in the design. Therefore, the main objective of the use case is a fast and reliable power

Use Case	Title	Description
		source transfer with the use of IEC 61850 GOOSE messaging system.
5	Enhanced Protection coordination for subs	Short-circuit faults on distribution circuits are typically detected and isolated by inverse-time overcurrent protective devices. The coordination between different over current elements installed along the distribution feeder and those located on the substation is achieved via time coordination with acceptable margins. However, this traditional approach may result in long operating times of feeder relays when the fault occurs in a location close to the substation. On the other hand, with the growing amount of distributed energy resources (DERs), bi-directional protection elements may have to be utilized for selective fault clearance. The anti-islanding protection of DERs shall also ensure that automatic reclosing will not fail and no unintentional island will be form as a result of fault isolation. This use case focus on the application of IEC 61850 communication system in order to enhance the protection coordination in distribution systems embedding DERs. The main objective of this use case is to enhance overcurrent protection coordination among conventional protective devices, particularly when the penetration of DERs is significant. More specifically, this use case will focus on three protection challenges and will demonstrate how IEC 61850-based communications among protection devices and DERs can address these issues. The issues are as follows: • Improved anti-islanding protection of DERs • Improved reclosing/relaying operation • Enhanced operation of feeder protection
6	DER Control Mode Modification	Large-scale integration of distributed energy resources (DERs), particularly high penetration of variable energy resources (VERs) such as PV systems, is causing adverse impacts on the power flow and quality of distribution circuits. In many cases, it is needed to control active and reactive power contribution of large DERs actively and frequently in order to manage voltage level across the circuit or to control large amount of re-verse power flow when the circuit is in light-load conditions. In some cases, the control modes of DERs should change to an active scheme such as voltage/frequency droop control to enable direct interaction with the grid. Control mode change (CMC) in DERs can improve system performance in a distribution grid dominated by DERs. The main objectives of this use case is to remotely change the control mode of a DER for the enhanced operation of the distribution system. More importantly, this will be done through IEC-61850 communication protocol to further facilitate DER integration into electric grid. Although large-scale DERs may directly be connected to distribution substation, the focus of this use case would be feeder-connected DERs.
7	Grid Support using DER	One of the key utility benefits claimed for the deployment of large-scale DERs is the grid supporting capabilities of these DERs. Examples of these capabilities include controlled reactive power contribution, active power adjustment, ride-through functionalities, and voltage control modes. While some control aspects of DERs are autonomous, i.e., they will happen automatically (and locally) in response to changes in the DER terminal

Use Case	Title	Description
		voltages and grid frequency, the DER control parameters can be modified remotely if the DER has proper communication features. However, adjustment of DER control mode/parameters would require co-ordination among multiple DER units, which can provide the service. This is to prevent any conflict among the control operations of various DERs. In addition, it is essential to coordinate the intelligent electronic devices (IEDs) located within the same vicinity with DERs to enhance. The main objective of this use case is to evaluate smart inverter functionalities of DERs that are recently introduced in order to facilitate grid integration and high penetration. The use case aims to effectively utilize DER control features in order to provide support to the distribution grid under various abnormal conditions. In particular, this use case will focus on the following two grid-supporting aspects: • Utilizing DERs to correct feeder power factor and/or to improve feeder voltage through management of the reactive power flow within the distribution feeder. • Coordinated use of DER ride-through capabilities to enhance system performance under network faults and/or transient disturbances.
8	Emergency Load Management	Currently, SDG&E performs surgical load shedding based on pre-determined look-up tables with rotational schedules for the distribution circuits that can be placed in outage in order. When an emergency load shed-ding request is made by California independent system operator (CAISO), the pre-scheduled look-up table will define which circuits shall be shed. The schedule incorporates information on type of customers connected to the circuits and excludes outage on circuits that serve critical facilities such as hospitals, elderly residential housing, fire stations, etc. However, since the current practice works based on the circuit interruption, there is a possibility that more loads than required amount are de-energized in response to a load-shedding request. With the increasing integration of distributed energy resources (DER), there will be opportunities to minimize customer interruption during emergency conditions. This can be done through effective utilization of DER contributions to offset customer loads. In other words, proper dispatch of DERs can potentially help with efficient load management in distribution circuits. If there are cases where loads must be disconnected, it can be determined based on real-time measurements and controls such that the smallest possible amount of load is de-energized to achieve the defined load-management target. Further, an improved rotational scheme can be employed to improve the load shedding strategy. The main objectives of this use case is to monitor field data and properly utilize DERs in order to: • Reduce the needs for disconnecting large amount of customers, based on the generation contribution from DERs, and • Use the real-time information from field assets to perform partial load shedding, to restore some loads through alternative power sources, if possible, and to rotate the scheduled outages more frequently as the need for load reduction changes.

Use Case	Title	Description
9	Dynamic Emergency Load Control and Management with DERs	This use case incorporates development of an OpenFMB communication platform for monitoring and control of DERs and field devices on distribution circuits. The objective is to investigate capabilities of OpenFMB framework for managing the communications among various field devices (primarily, DERs and feeder breaker).
10	Dynamic Circuit Load Management with DERs	This use case focuses primarily on the development of an IEC 61850/MMS communication platform between SCADA and substation gateway/controller for monitoring and control of DERs and field devices on distribution circuits. The communications with field assets, including DERs is done via IEC 61850/GOOSE protocol, but the DNP 3.0 communications between the SCADA and substation was replaced with MMS to conduct a comparative analysis.
11	Volt-var control via OpenFMB	The objective of this use case is to demonstrate how the OpenFMB communications platform can be utilized with a variety of DER devices equipped with legacy protocol interfaces to enable DER to DER communications and implement a Volt-var scheme utilizing DER assets.

2.6.3 Data collection

In order to analyze the performance of the system it was essential to collect measurements, statuses, setpoints, and commands during each test. Three approaches were simultaneously used for data collection during the testing:

- The SCADA (EVENTA) was continuously recording all the analog and binary values reported from the system (RTDS). This data was recorded for the purpose of performance evaluation. The time resolution for archiving the data was adjustable in SCADA, and the project selected an appropriate time resolution required for post-mortem data analysis depending on the use case.
- The Substation HMI (MicroSCADA) was also recording a list of desired parameters during each test; including desired breaker powers, switch statuses, DER outpour powers, trip and pickup signals, cap bank statuses, etc.
- A list of important signal (binary and analogues) were saved in the RTDS in the COMTRADE format. These results were used for comparison against the baseline system without IEC 61850 communication.

2.7 Phase 3 – Task 6: Build the test system

2.7.1 Test plans

Test plans were created for both Factory and Site Acceptance Testing. The test plans incorporated a comprehensive set of tests to evaluate both basic device interconnectivity, as well as those specifically created to test the various use cases for the different configurations.

A number of performance criteria has also been identified and analyzed to evaluate the level of efficiency. Some of the main performance criteria considered for this study include (but not limited to):

- DER integration using ICE 61850 communication
- DER involvement/contribution
- Improved fail-safe scheme
- Coordination between protection system and Low-Voltage Ride-Through (LVRT) capability of DERs
- Improved protection coordination between substation and feeder devices
- Improved customer reliability
- Reverse power flow management in the presence of intermittent DERs

The comparisons are made against a baseline system in which conventional communication schemes are utilized (no IEC 61850 communication in place).

2.7.2 System setup

The hardware components identified in the previous section were procured and installed in three 19" racks.

- Two racks were used to house all the protection, automation and control equipment used inside the substation.
- One rack housed all protection and control equipment used outside the substation, i.e., along the feeder or in the field (feeder automation devices).

Figure 2-13 and Figure 2-14 below show the three sets of racks containing the various substation and feeder equipment described in the previous task.

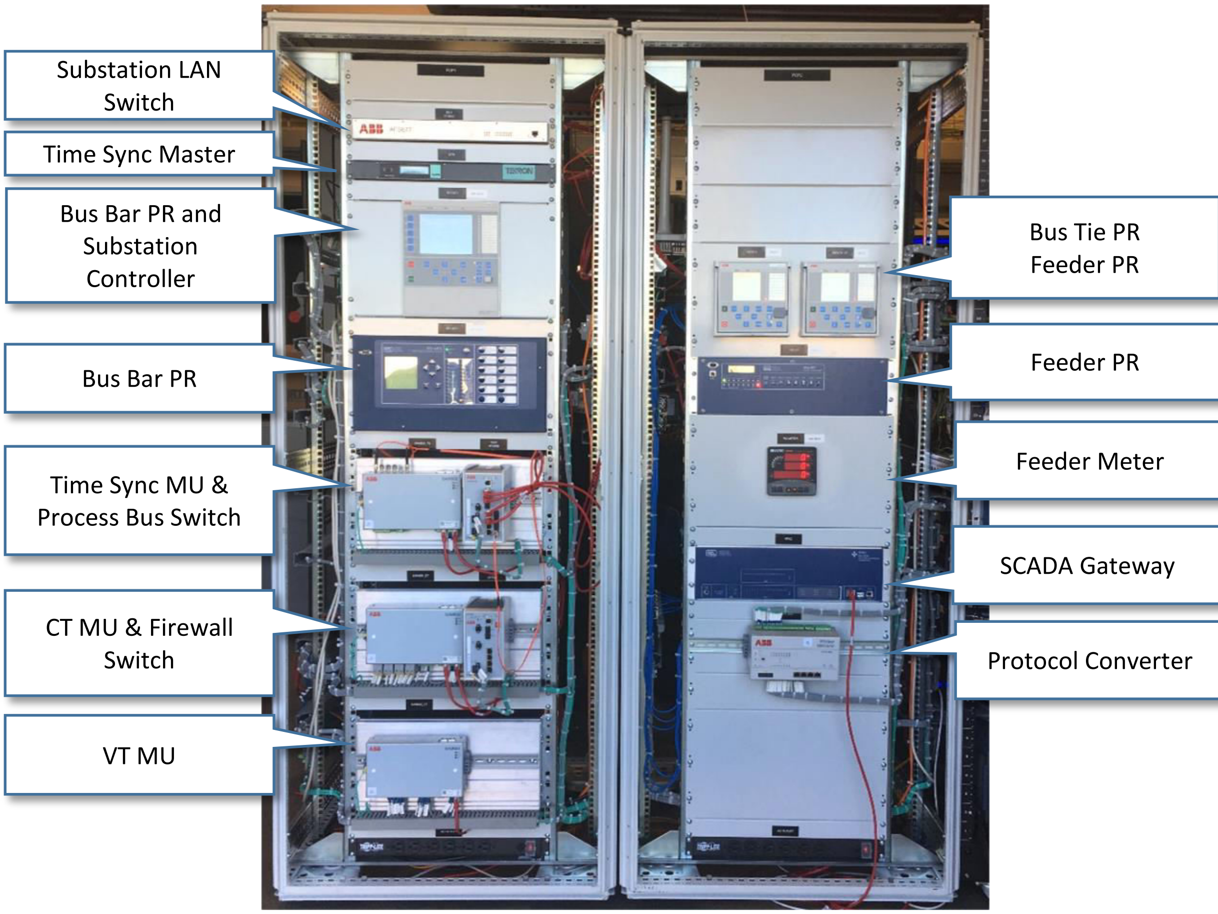

Figure 2-13. Substation racks.

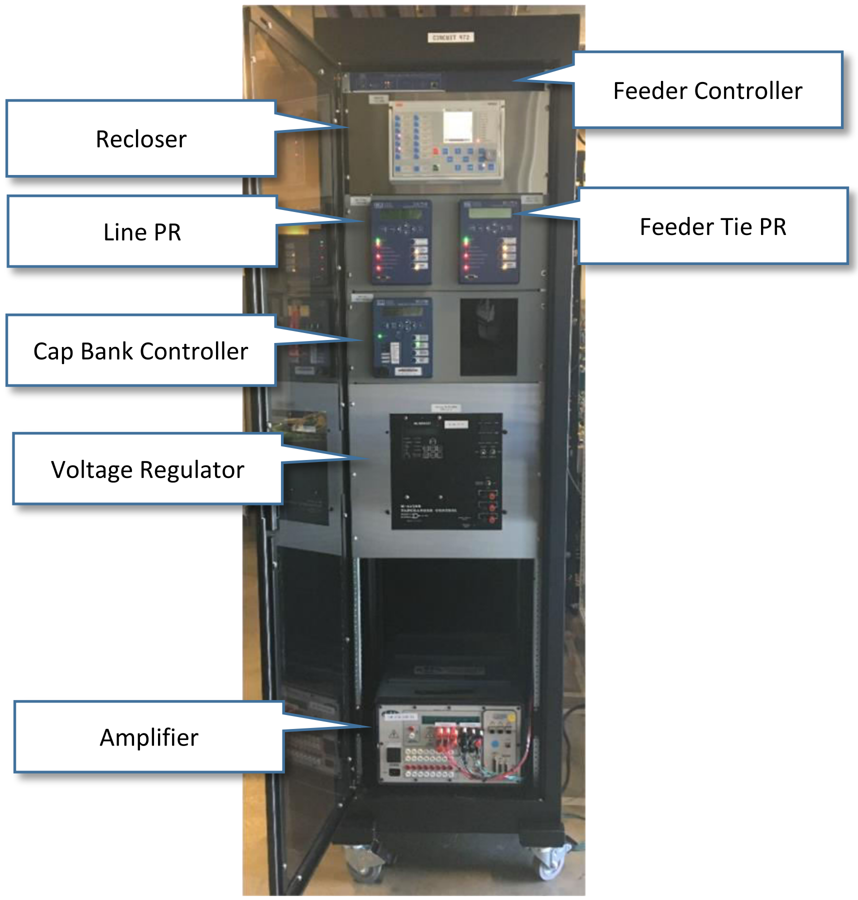

Figure 2-14. Feeder rack.

2.8 Phase 3 – Task 7: Perform the demonstration

Testing of the system was implemented in three separate phases:

- Separate Factory Acceptance Testing of the substation and feeder racks with limited hardware-in-the-loop[12]
- Factory acceptance testing of the integrated system with additional hardware-in-the-loop
- Site acceptance testing of the complete model with extensive hardware-in-the-loop, including an actual Battery Energy Storage System and smart PV inverter.

2.8.1 System Tests

The two Factory Acceptance Tests and the Site Acceptance Test were conducted over a staggered period with a total duration of approximately 4 weeks. Each of the sessions built on the experience gained during the subsequent test cycle and, as progressively more equipment was integrated into the system, the tests became more complete, more complex, and more representative of the real-world system the project aimed to simulate and test.

In addition to the testing of the application-specific use cases (defined in more detail in the sub sections that follow), several use case independent tests were performed to verify the interconnection of system components via the three primary protocols in use:

1. Interface 1: SCADA communications between the control center and the Substation via DNP 3.0
2. Interface 2: SCADA communications between Substation and Feeder equipment using the MMS communication service
3. Interface 3: Peer-to-peer communications among substation and field devices using the GOOSE communications service

2.8.1.1 Interface 1: Communications between control center and Substation SCADA Gateway

Several tests were executed to verify communications between the SCADA gateway and the control center as enumerated in Table 2-15.

Table 2-15. Interface-1 communication test cases (DNP3)

Case#	Test Case	Description
0.6	IP/Port number verification	Ensure that RTAC and SCADA server can ping each other
0.7	Analogue input (measurements) reading by SCADA	Change the power flow of the circuit and verify that the changes are reflected in the SCADA HMI
0.8	Analogue output (setpoints) writing by SCADA	Issue setpoints and/or curtailment signals to the substation BESS and/or PV systems and verify that they are applied correctly
0.9	Binary input (status) reading by SCADA	Change the status of switching devices and verify that the

[12] Necessitated by the two sets of racks being constructed in two different locations: the two substation racks in Raleigh, North Carolina, at ABB's Smart Grid laboratory, and the Feeder rack in Toronto, Ontario, at Quanta Technology's Sustainable Technology Integration Laboratory (QT-STIL).

Case#	Test Case	Description
		changes are reflected in the SCADA HMI
0.10	Binary output (commands) writing by SCADA	Send open/close command to switching devices (or tap up/down a VR) and verify that it is applied properly

2.8.1.2 Interface 2: Communications between Field/Substation and Substation Controller

The tests of this section are aimed to verify MMS communication between the substation MicroSCADA (SYS600) and substation/field devices. Table 2-16 lists major Group-2 test cases.

Table 2-16. Interface-2 communication test cases (MMS)

Case#	Test Case	Description
0.11	IP/Port number verification	Ensure that all relevant devices can reach to each other.
0.12	Analogue input (measurements) reading by MicroSCADA	Change the power flow of the circuit and verify that the changes are reflected in the MicroSCADA HMI
0.13	Analogue output (setpoints) writing by MicroSCADA	Issue setpoints and/or curtailment signals to the substation BESS and/or PV systems and verify that they are applied correctly
0.14	Binary input (status) reading by MicroSCADA	Change the status of switching devices and verify that the changes are reflected in the MicroSCADA HMI
0.15	Binary output (commands) writing by MicroSCADA	Send open/close command to switching devices (or tap up/down a VR) and verify that it is applied properly

Several tests were executed to verify the MMS communications between the MicroSCADA and field/substation devices. Figure 2-15 shows a snapshot of the MicroSCADA HMI for a particular system operating condition. The comparison between values shown on the HMI and the actual values in RTDS (or seen by the actual device) indicate proper communications between the MicroSCADA and field/substation devices. The operator can also send command to devices through the MicroSCADA HMI, which was confirmed in this testing. For the sake of brevity, the results of all tests will not be presented in this report.

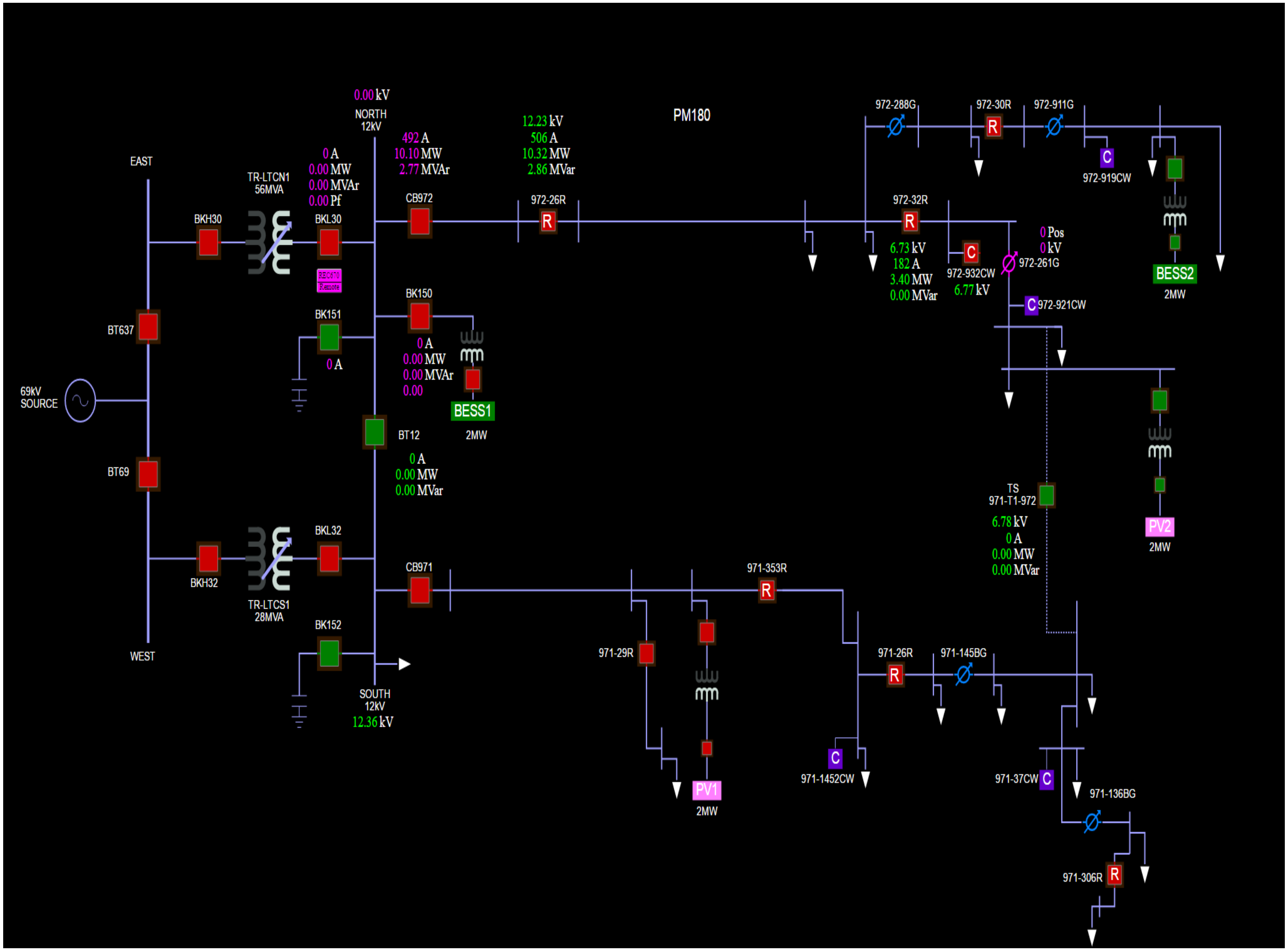

Figure 2-15. Snapshot of the MicroSCADA HMI for a particular system operating condition

2.8.1.3 Interface 3: Peer-to-Peer and analogue sampled values communications

The most important (and challenging) part of this test category is to verify the multi-cast GOOSE communication between various IEDs in the system (peer-to-peer communication) and the sampled analogue values published by the merging units. To facilitate this part of the testing, an integrated testing tool from vendor 2 will be used. The tool is a substation automation tool that enables easy diagnosis and troubleshooting of IEC 61850 configuration in P&C IEDs, the visualization of GOOSE messages and sampled values streams, and the communication simulation of an IED. With the use of this tool, the communication verification for an IEC 61850 compliant automation system and/or application can be done effectively, such that the root cause of the communication issue can be identified.

Table 2-17 provides a list of major tests that have been conducted to verify GOOSE and Sample Value (SV) communications among various IEDs. A comprehensive set of tests was conducted to ensure the desired devices can communicate in a peer-to-peer (P2P) manner. Due to the space limitations, however, the results of only a limited number of tests are presented and briefly discussed in this section. It is worth noting the majority of use-case studies in this project require devices to have direct (P2P) communications.

Table 2-17. Interface 3 communication test cases (GOOSE and SV)

Case#	Test Case	Description
0.16	IP/Port number verification	Ensure that all relevant devices can reach to each other.
0.17	Analogue GOOSE (measurements)	Change the power flow of the circuit and verify that the changes are reflected in the subscribing IED
0.18	Binary GOOSE (e.g., trip)	Issue trip signals to a feeder IED and verify it is received correctly
0.19	Double Point GOOSE (e.g., Circuit Breaker Position)	Change the status of switching devices and verify that the changes are reflected in the subscribed IED
0.20	Sampled Value stream published by a merging unit and subscribed by an IED	Inject analog value to merging unit and verify value is correct at subscribing IED

Figure 2-16 and Figure 2-17 show binary and an analog GOOSE messages sent by two different IEDs to provide various functionalities. The binary GOOSE message shown in Figure 2-16 is a trip signal sent by RER620 recloser relay to trip breaker CCR2-32R for a downstream fault on bus 305. The breaker is subscribing to this message, and as soon as the trip message is issued, the breaker will open.

The analog GOOSE message shown in Figure 2-17 is the real power flowing through the substation transformer (LTCN1 in Figure 2-11). These power values are calculated and published by REC670 relay. The feeder controller (substation RTAC in Figure 2-11) subscribes to these values to calculate and control system power factors on a real-time basis.

After completion of the system tests and verification that all interfaces were operational, the use cases were tested. The sections that follow describe each of the use cases in detail.

Figure 2-16. A binary GOOSE message sent by RER620 to trip CCR2-32R for a downstream feeder fault

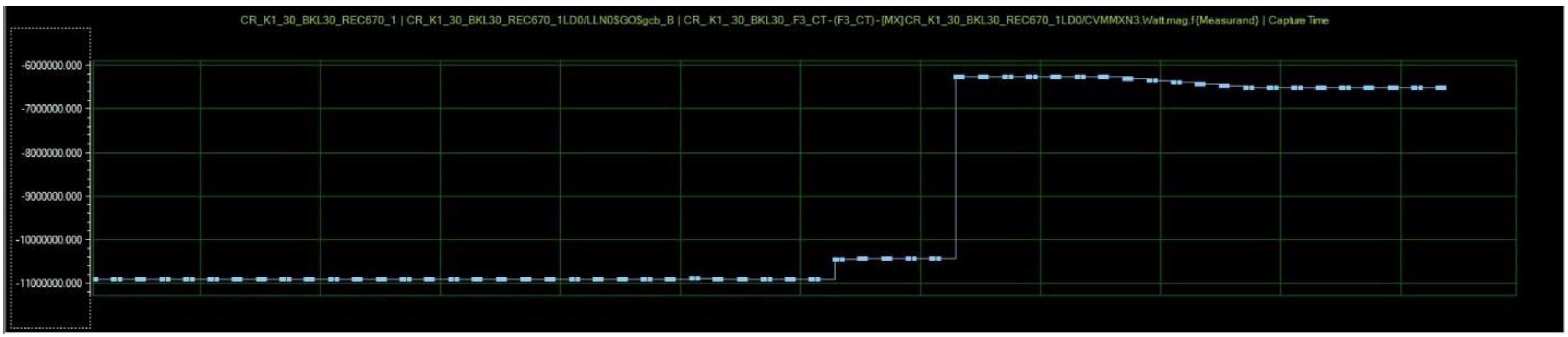

Figure 2-17. Analog GOOSE message sent by REC670 to RTAC to be used in GS-DER use case

2.8.2 Use Case 1: Lifecycle asset provisioning and integration with IEC 61850

2.8.2.1 Problem statement

The utilization of the IEC 61850 standard in protection and automation systems will require a change of design, engineering, building, commissioning, and maintenance procedures used today. Many of the previous tasks are replaced by software configuration and programming with new standard software tools. The engineering process is based on the use and exchange of XML-based description of IED and system configurations and capabilities. During the lifecycle of an automation and protection system, changes, replacements, extensions, and reductions of the system are typical scenarios that need special consideration.

2.8.2.2 Objective

The objective of this use case is the demonstration of the engineering process to:

- Create IEC 61850 system configuration files including
    - MMS mapping and HMI integration
    - Peer-to-peer (GOOSE) communication between IEDs
    - Sample values assignments (process bus)
- Facilitate documentation method of a system design and implementation
- Update and reconfigure an existing system easily
- Add, remove, or replace single components (IEDs) in the existing system

The term IED (intelligent electronic device) is, in the following, used for any intelligent protection and control devices and includes advanced DER controllers, protection relays, DFRs, tap changers, voltage controllers, reclosers, etc.

2.8.2.3 Description

The use case tests start with an existing system configuration description file (SCD) that has integrated all substation components as specified in the test setup. The objective of these test cases is to investigate how IEC 61850 can facilitate life-cycle provision and integration of the new/replaced IEDs. The following are the most common scenarios utilities will be confronted with in terms adapting an existing engineered system in service.

2.8.2.3.1 Integration of a new IED

The standard allows for different sequences to add a new device to an existing system The two most common are either “top-down”, where the engineering starts at the system configuration tool, or “bottom-up”, where the configuration starts with the IED tool. Today, the most common method is bottom-up, as it is the scenario supported by most vendors. Therefore, the use case is also focusing on the bottom-up approach. The process and the engineering tools involved to engineer the IEC 61850-based solutions are illustrated in the upper part of Figure 2-18. It starts with the configuration of the IEDs using the corresponding IED configuration tool. Data modeling and communication information is then exported according IEC 61850 as CID file. The CID file of the new device is imported to the system engineering tool in order to complete the data flow engineering for the newly added device. Part of the data flow engineering is to connect the data from the newly-added device with any potential subscriber (for GOOSE) or client (for MMS). The result of the data flow engineering is documented as a machinereadable SCD file. Any device that requires data from the new device will need to be updated based on the new version of the SCD file. The SCD file is also used to ensure consistent documentation of the IEC 61850 data model and the system communication of the completely engineered system. Subsequent changes are always updated in the latest system configuration data file (SCD). In practice, the SCD import by the IED tool may not always be supported and thus a subset (e.g., a CID file instead) may be used as explained later.

The steps required to add a new IED for a traditional solution based on DNP3.0 and hardwired interconnection is outlined in Figure 2-19 for comparison. Even though the approach and process to engineer a classic protection and automation solution based on hardwired interconnections and DNP3.0 communication are not analogous to an IEC 61850 solution, a similar structure has been applied for the sake of comparison in order to highlight the benefits and drawbacks of an IEC 61850-based solution.

IEC 61850 engineering tools and data flow used for use-case testing is illustrated in Figure 2-20. Essentially, two different tools had been used to add the new IED. An SEL-351 was chosen as the new IED, and the Vendor 1's configuration tool was used as the IED configuration tool. On the system side, the IEC 61850 engineering functionality inside Vendor 2's configuration tool was used for the data flow engineering and creation of the SCD file.

2.8.2.3.2 Removing an existing IED

Removing an existing IED from the system may be required in cases of de-commissioning certain feeders, but removal may also apply in cases of an existing IED becoming obsolete and being replaced with a new device from a different manufacturer. In this case, the existing IED needs to be removed before adding the new IED. The steps required to remove an existing IED from the system is illustrated in Figure 2-21. Basically, within three steps, an IED can be removed from an IEC 61850 based system. All activities can be done centrally (e.g., from the systems engineering computer with access to all IEDs). In the case of a traditional hardwired solution, not all activities can be handled from a central engineering workstation. There is a fair amount of hands-on work involved to remove the physical interconnection cables. Figure 2-22 presents the main steps to remove an existing IED from a traditional system.

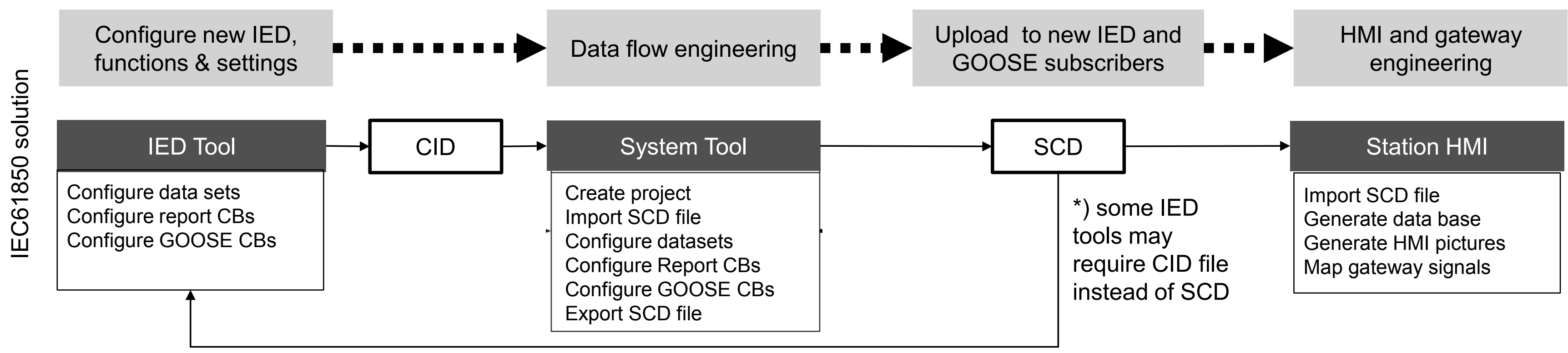

Figure 2-18. Main steps to integrate a new IED for an IEC 61850 based system

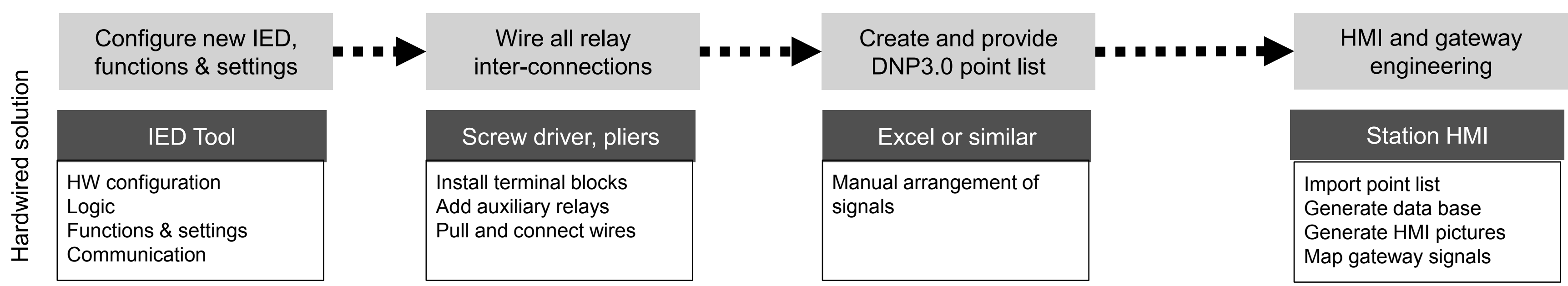

Figure 2-19. Main steps to integrate a new IED for a system with DNP3.0 and hardwired interconnections

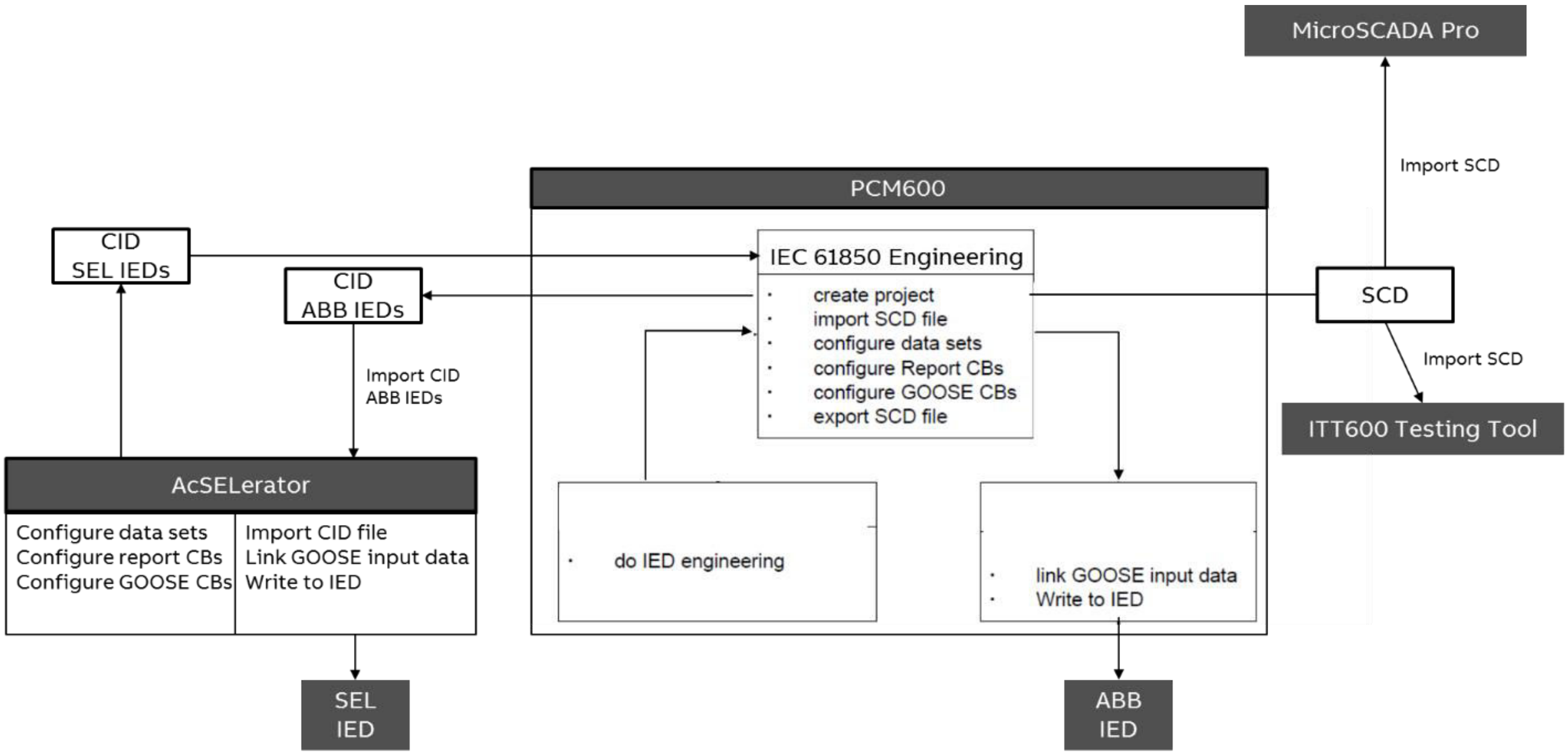

Figure 2-20. IEC 61850 engineering tools and data flow

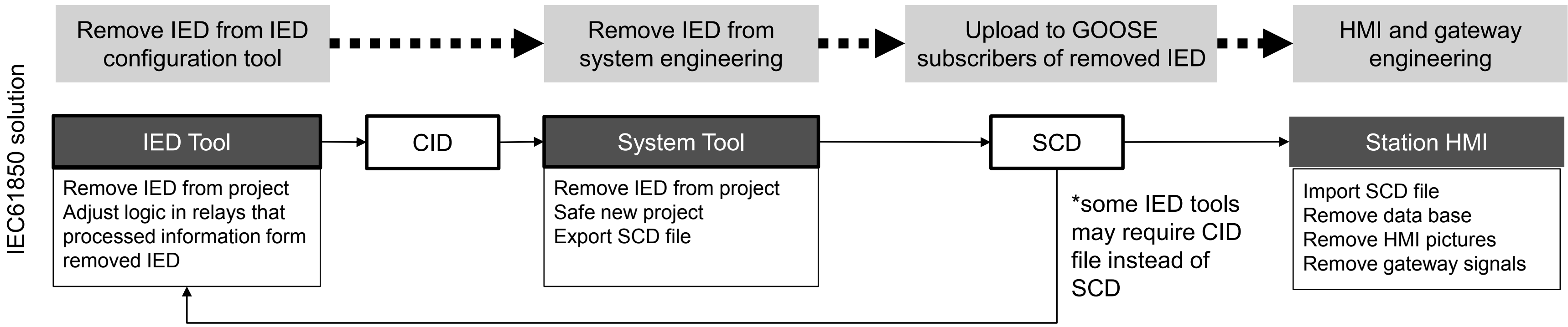

Figure 2-21. Main steps to remove an existing IED from an IEC 61850 based system

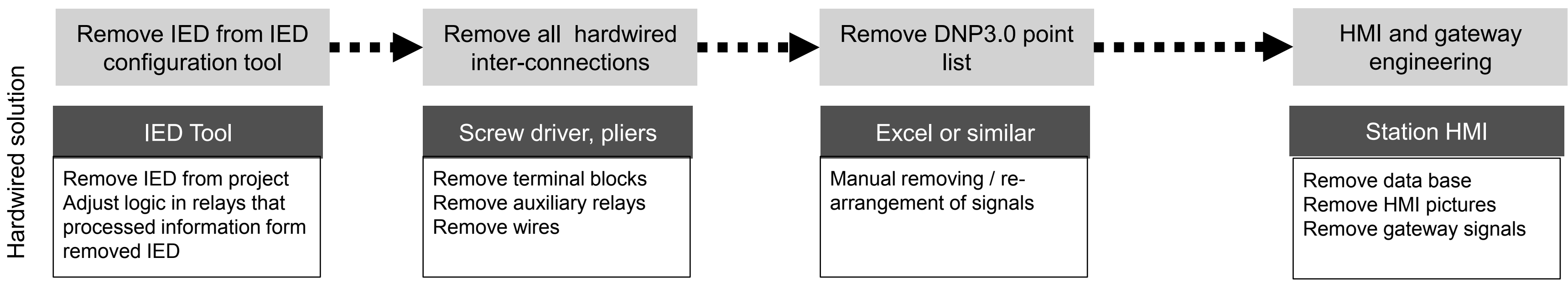

Figure 2-22. Main steps to remove an existing IED from a traditional system

2.8.2.3.3 Replacing a failed IED in an existing system

A very common scenario is the need to replace a faulty device in an existing system. Ideally, the new IED that replaces the faulty IED is an identical device, meaning same manufacturer, model, and version. In such a case, minimal effort is required to replace the faulty device. Basically, the backup configuration needs to be loaded to the new installed device. In cases where the new device differs from the failed device, the two scenarios explained earlier apply ("Removing an existing IED" and "Integrating a new IED"). By combining these two steps, one can reduce the number of configurations downloaded to the relevant IEDs to only one cycle.

2.8.2.3.4 Replacing a failed time source in an existing system

The time sync source is a special case. Although part of the IEC 61850 based system, it does not provide IEC 61850 data models and/or communication services and its sole function is to synchronize all of the different devices within the IEC 61850 system. In addition to the SNTP and IEEE1588 PTP recommended by the standard, IRIG-B and PPS were also implemented in the test system because some of the IEDs did not support SNTP. The replacement of a failed time server device does not impact the IEC 61850 engineering files (e.g., the SCD file). It is sufficient to keep a backup of the configuration and load it back into the new time server device in case of replacement. If a faulty time server is replaced with a different brand and model, the configuration needs to be re-created using the relevant parameters of the failed unit, including Ethernet port addressing and parameters for SNTP and PTP.

2.8.2.4 Test cases and results

Table 2-18 presents the lifecycle asset provisioning test cases and results.

Table 2-18. Lifecycle asset provisioning test cases and results

Test #	Test case	Description (IEC 61850 design)	Results Conventional Design	Results IEC 61850 Design
1	Integrate new IED into existing system	- Configure new IED, functions and settings - Provide ICD/CID file of the new IED device - Import ICD/CID file to system engineering tool - Engineer data flow - Upload SCD/CID to new IED and GOOSE subscribers - Add new signals and pictures to HMI and gateway - Basic test of communication (Ping, MMS, GOOSE)	- There is no standard process defined. - No formal definition on how to document engineered solution - Hardware required to establish interconnection between IEDs	- **Clear workflow according IEC 61850, button up method verified successfully.** - **Consistent SCD file for complete system documentation of IEC 61850 portion created.** - **Some efficiency challenges observed with certain products.**

Test #	Test case	Description (IEC 61850 design)	Results Conventional Design	Results IEC 61850 Design
2	Remove existing IED from existing system	- Update system engineering by removing IED device - Upload SCD/CID file to devices subscribing to GOOSE of removed IED - Remove signals and pictures related to removed IED at the HMI and Gateway	- Configuration as well as mechanical work is required. - Simulation is not possible.	- **All activities can be done from a central engineering workstation. A safe and efficient approach. The impact of a removed IED can be simulated before it is removed.**
3	Replace failed time source device into existing system	- Upload existing configuration file to new time master device - Check correct synchronization of connected devices	- Replacing the hardware and loading new configuration is straight forward. - Supervision is more limited especially if IRIG-B method is used.	- **Replacing the hardware and loading new configuration is straight forward.** - **The verification of correct time sync is automatically done as it is part of the quality information in the messages and time server can be accurately supervised**

Problem
Improved Result

2.8.2.5 Findings

Comparing the tasks required for an IEC 61850-based solution versus a traditional solution using DNP3.0 for the communication to an RTU and using hardwired interconnections between IEDs for the given scenarios show that, overall, the steps are similar; however, the biggest difference is when communication is applied to replace hardwired interconnections. With IEC 61850, all interconnections are engineered virtually by applying GOOSE and sampled-value real-time communication services. The greatest benefit is that the complete engineering can be handled within the IED and system tools (and testing is possible immediately after the engineering is complete using the IEC 61850 testing tools), making the process of engineering and testing extremely efficient. With a traditional solution, additional tools and hardware are required, and testing takes more time as relevant infrastructure needs to be made available.

The demonstration of the different scenarios and related use cases proved that the engineering process as defined in the IEC 61850 reference model worked. However, depending on the capability of the specific IED tool, some deviations may need to be addressed. For example, not all IED tools support the import of the SCD file. This could discourage engineers from creating an SCD file as the benefit is not immediately visible when looking only at the engineering process. It is still highly recommended to create an SCD for each system to ensure consistent documentation of the IEC 61850 portion. In addition to simplifying the process of configuring the interfaces to, and the databases of, Station HMIs and gateways, the process of engineering and troubleshooting is also much easier.

Having the IEC 61850 system engineering capability built-in to the IED configuration tool is an advantage, as no extra steps are required to import / export the IEC 61850 configuration as SCD files.

Using the IEC 61850 standard for documentation (SCD file) is a good way to document all IEC 61850 relevant information, including data modeling, substation communication services, and network structure. What is missing is the documentation of the link between the IEC 61850 signal and the IED internal variables or logic. This was resolved in this project by creating a GOOSE table that documented these internal connections.

Basic communication and data model verification can be automated using an IEC 61850 testing tool. Beyond the basic communication test, it also provides verification of software and configuration revisions, including SCL consistency checks, by automatically scanning the network for any connected IEC 61850 device and comparing the scanned information with the original SCD file.

2.8.3 Use Case 2: Maintenance testing of IEDs

2.8.3.1 Problem statement

For maintenance purposes – replacing existing/failed IEDs, logic change/upgrade, or adding new IEDs to the system – a condition-based testing is performed on IEDs to confirm their proper operation. To do this, the test engineer must isolate the IED under test from the system to avoid any undesired breaker operations during the testing process. In the case of wired-connected systems, the test engineer should open test switches to perform maintenance tests. However, the situation is much different in an IEC 61850 environment, where the isolation of the relay/IED can be done through communications. This use case demonstrates how IEC 61850 communications can facilitate field-testing of IEDs, as compared to the traditional wire-connected systems.

2.8.3.2 Objective

The objective of this use case is to demonstrate the isolation, testing, and simulation mechanism for GOOSE and process bus links provided by IEC 61850 Edition 2. To verify the capability and advantages of these features, the test cases are subdivided in two main topics:

1. Functionality of the modes and behavior – On, On-blocked, test, test-blocked
2. The sampled value data received through an external device using the simulated flag

2.8.3.3 Description

The IEC 61850 standard provides a mechanism that allows for the isolation of an IED for field testing purposes. In Edition 1, the interpretation of the mode and behavior of this feature was not described, and the implementation of this mechanism was only possible by configuring specific logic in the IEDs. Edition 2 of the standard addressed these short comings and clarified these “gray areas” by providing specific rules regarding the behavior of the different modes. To enable interoperable testing and isolation out of the box, without application-specific programming, the modes selection and quality information according IEC 61850 Edition 2 is applied.

In the project system setup, the SEL relays used were only supporting IEC 61850 Edition1. Therefore, the entire system was set up as an IEC 61850 Edition 1 system. In order to execute the test cases for this use case, two Vendor 2 IEDs were selected out of the complete system setup. They were re-configured as

IEC 61850 Edition 2 devices for these particular tests. Figure 2-23 illustrates the setup used to perform the tests related to this use case.

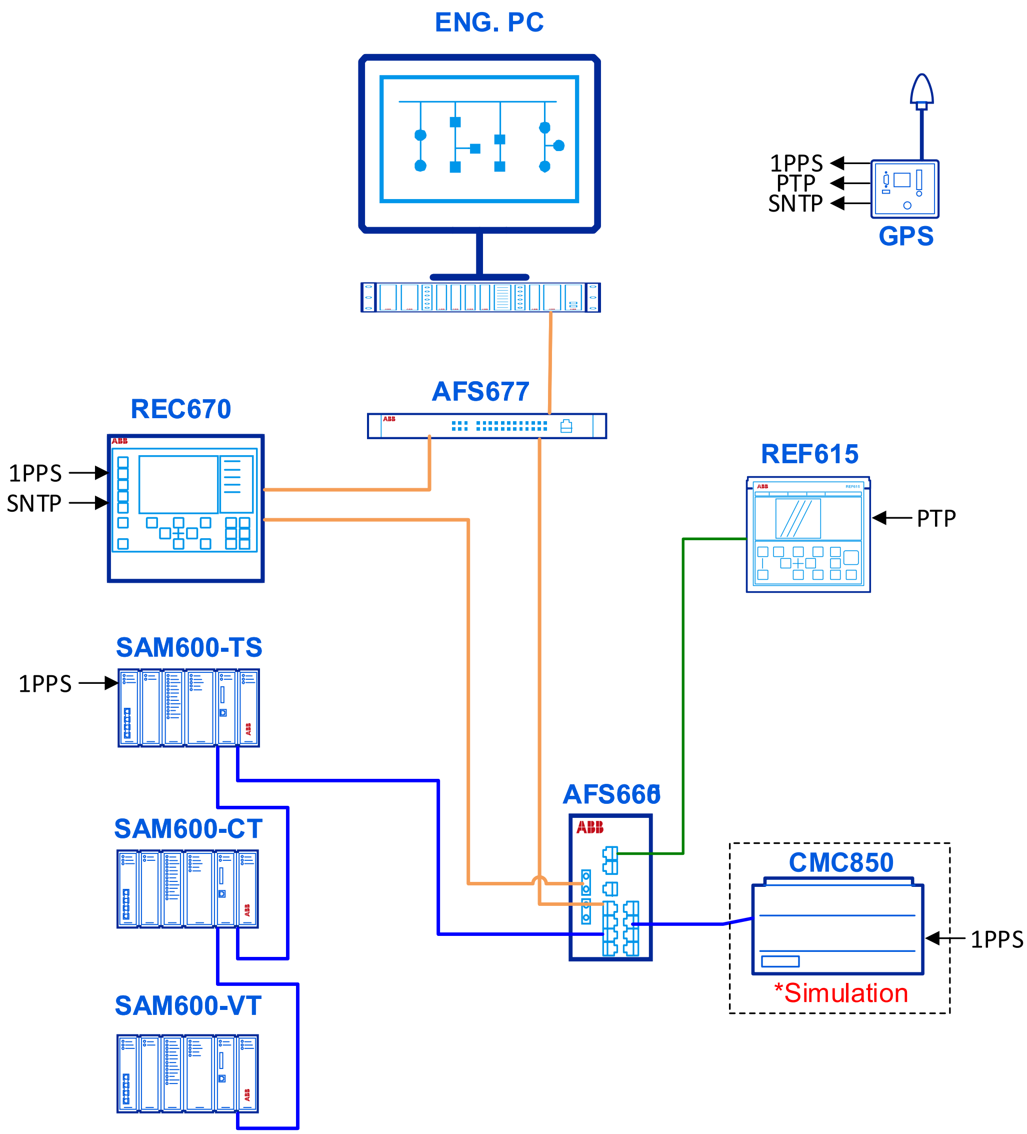

Figure 2-23. Test set-up for maintenance testing of IEDs

2.8.3.4 Isolation of an IED using mode/behavior

In traditional solutions, where hardwired interconnections between IEDs are used for bay to bay information exchange but also where hardwired connection between bay level and process level is used, isolation of equipment under testing is done using test switches. The test switch installed between the IED and the process allows for the disconnection of individual connection in order to test (i.e., protection functions without tripping the breaker).

With IEC 61850, the hardware connections between relays, and between relay and process, become virtual by using real-time communication to exchange data between the different functions allocated at the station and process level. In order to isolate devices in these modern systems, other means are required. That is where the standard definitions for mode and behavior come into play.

In this use case, the proper behavior of an IED for the different mode of operation has been tested. The main focus was to verify and confirm the treatment of the GOOSE and SV message under different mode operation. The different modes and their behavior are illustrated in Figure 2-24.

2.8.3.4.1 Simulation of data and measurements

Setting the simulation to TRUE allows the IED under test to subscribe to GOOSE or SV streams from a simulated device or a test set. The simulation flag in the GOOSE or SV message indicates whether the signal is original or simulated. A data object in the logical node LPHD defines whether an IED will receive the original or the simulated message. If the data object Sim is set to TRUE, then the IED will receive all GOOSE and SV messages with a simulation flag set to TRUE. If, for a specific GOOSE or SV message, no simulated message exists, the IED will continue to receive the original message. The two behaviors with Sim=FALSE and Sim=TRUE are illustrated in Figure 2-25.

2.8.3.4.2 Testing protection using isolation and simulation

A complete test scenario addressing bus zone protection is demonstrated in this section.

The IEC 61850 Edition 2 mode and simulation features allows for virtual isolation of the bus zone protection IED for testing purposes. The steps required to isolate the different devices involved in the testing, and how to run the protection test using a test set sending simulated sampled value messages, is illustrated in Figure 2-26. The sequence of actions is as follows:

1) Set the mode of the REL615 protection IED to “Test”
2) Set the mode of the REC670 unit to “Test/Blocked”, so that it will accept GOOSE communication from protection IED under test but not trip the real breaker
3) Inject a fault current/voltage to the REF615 using the RTDS
4) The protection function of the REF615 trips and sends a GOOSE to trip the breaker connected to REC670
5) The REC670 confirms the correct tripping of the breaker by sending position operation OK, which is capture by Vendor 2’s configuration tool acting as an MMS client; the REC670 will not operate the tripping contact as the device is in test/blocking mode

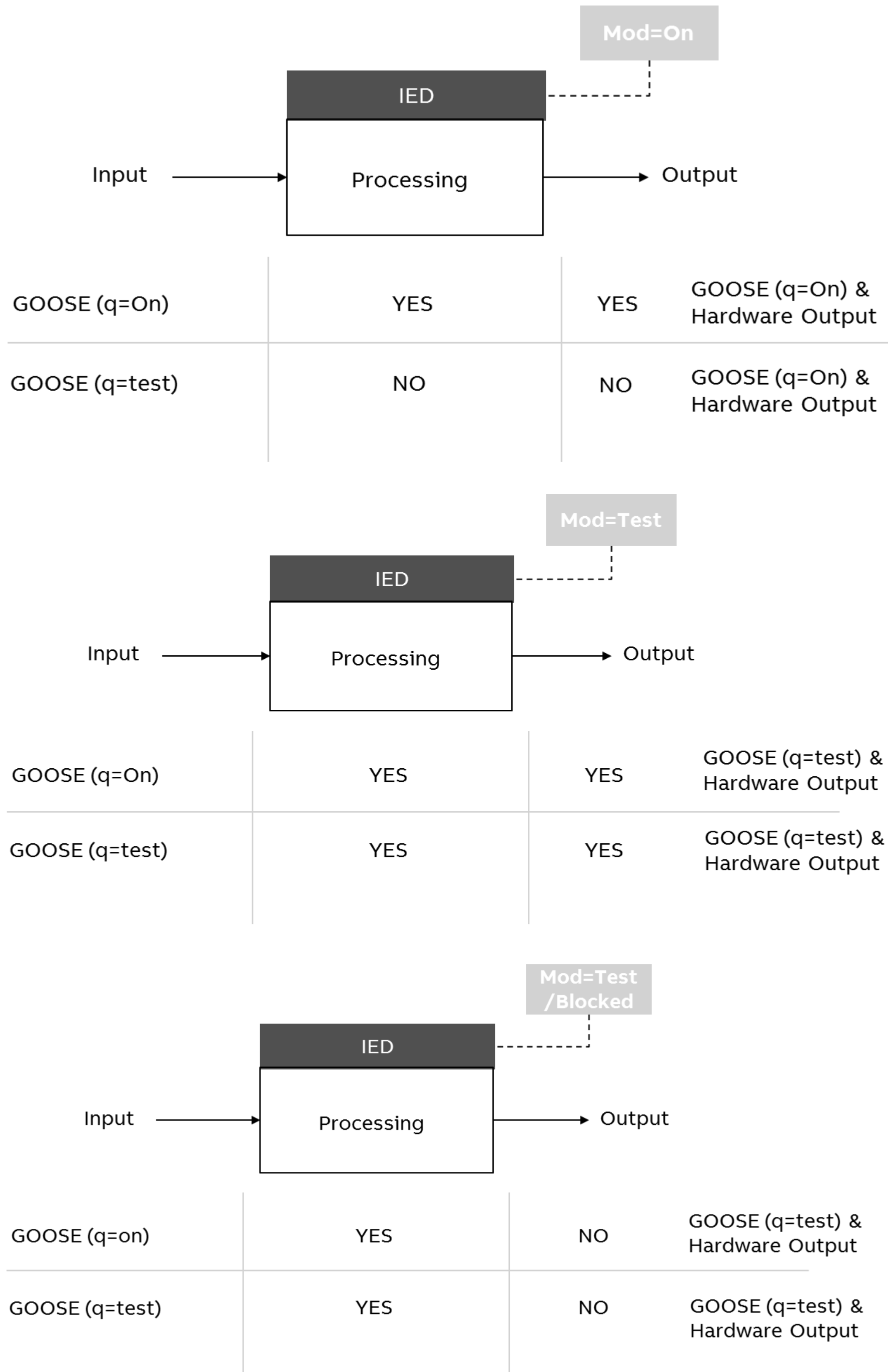

Figure 2-24. Behavior of different test modes used for IED maintenance testing use case

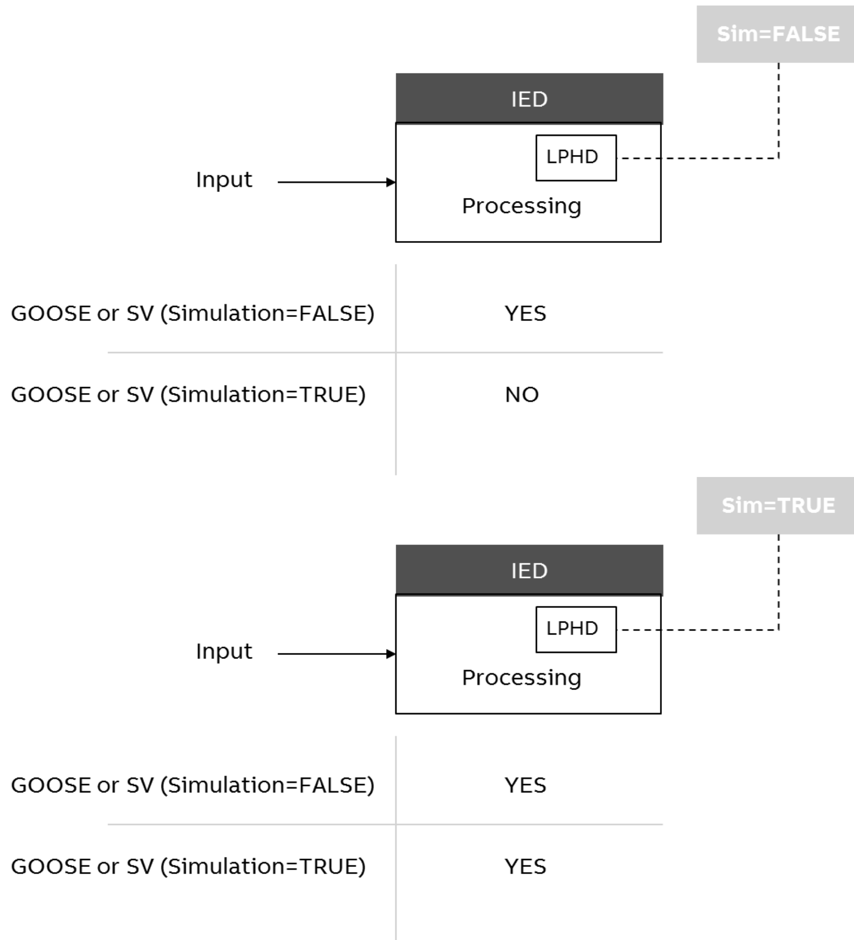

Figure 2-25. Behavior of different simulation modes used for IED maintenance testing use case

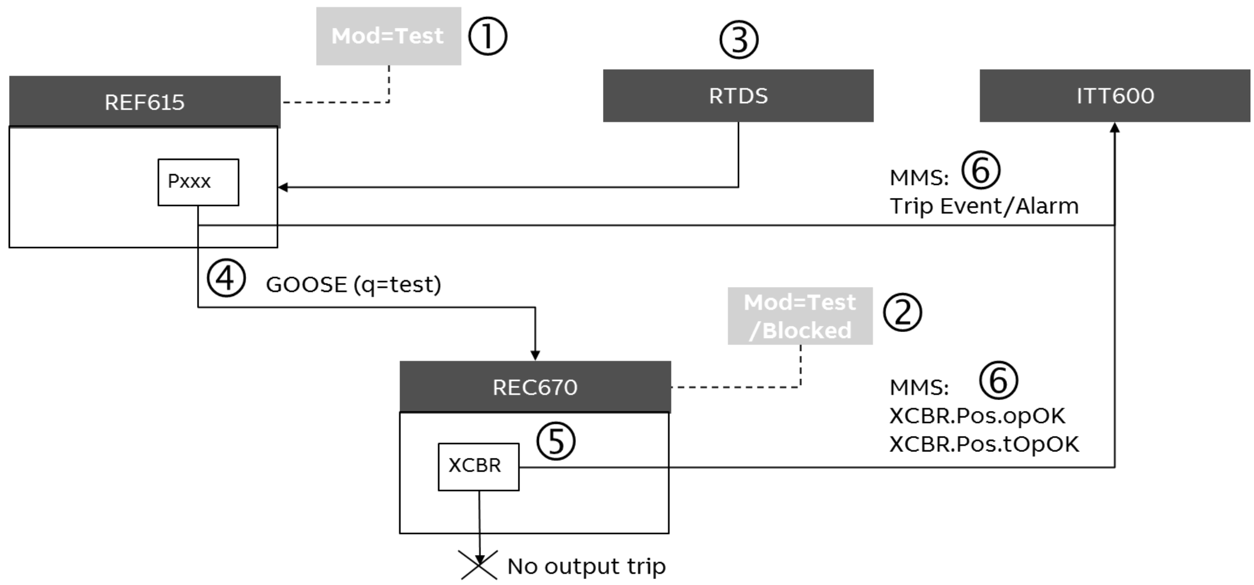

Figure 2-26. Isolated testing using IEC 61850 test mode

2.8.3.5 Test cases and results

Table 2-19 presents the maintenance testing of IEDs test cases and results.

Table 2-19. Maintenance testing of IEDs test cases and results

Test #	Test case	Description (IEC 61850 Design)	Results Conventional Design	Results IEC 61850 Design
1	Normal operation IEC 61850 Edition 2 Mode: On	- Set both IEDs to mode=on - Publish a GOOSE message from REF615 to REC670 - Confirm REC670 is receiving the GOOSE message correctly	Normal operation	Normal operation
2	Isolation of an IED IEC 61850 Edition 2 Mode: Test	- Set REF615 to mode=test - Publish a GOOSE message from REF615 to REC670 - Confirm that REC670 is not accepting the GOOSE message with q=test	Local, physical disconnection of interconnection wires	IED can be set to test mode, one command isolates all signals, control via contact, IED HMI or from remote, protected by role based access control
3	Isolation of multiple IEDs IEC 61850 Edition 2 2 IEDs Mode: Test	- Set REC670 & REF615 to mode=test - Publish a GOOSE message from REF615 to REC670 - Confirm that REC670 is accepting the GOOSE message with q=test	Local, physical disconnection of interconnection wires at multiple locations	Send a test mode command to each IED that needs to be isolated
4	Blocking outputs	- Set REC670 to mode=test/blocked - Publish a GOOSE message from	Local, physical disconnection of	IED can be set to test mode, one command

Test #	Test case	Description (IEC 61850 Design)	Results Conventional Design	Results IEC 61850 Design
	IEC 61850 Edition 2 Mode: Test/Blocked	REF615 to REC670 - Confirm that REC670 is accepting the GOOSE message with q=test - Confirm IED under test does not trip the breaker	process connecting wires	blocks all output contacts, control via contact, IED HMI or from remote, protected by role based access control
5	Connecting test-set IEC 61850 Edition 2, Simulation=Off	- Set REC670 to simulation=off - Publish a simulated sampled value stream where REC670 is a subscriber using the Omicron Test set - Confirm REC670 is ignoring the simulated sampled values	Wire multiple copper cables from test set to test switch contacts, attention required in order to not have open CT circuits	Connect test set to process bus access point (1 Ethernet cable), no risk of open CT circuits
5	Testing with injection IEC 61850 Edition 2, Simulation=On	- Set REC670 to simulation=On - Publish a simulated sampled value stream where REC670 is a subscriber using the Omicron Test set - Confirm REC670 is processing the sampled value from the test set	IED performs function based on injected values	IED performs function based on injected values. SV can be monitored and captured with IEC 61850 testing tool for documentation

Problem
Improved Result

2.8.3.6 Findings

IEC 61850 Edition 1 did not completely address all requirements needed for interoperable testing (e.g., the ability to isolate and inject simulated test messages). In order to enable such functions with an Edition 1 system, custom application programming is required in the IEDs. Edition 2 has been extended to support a “Simulation” Mode. In Simulation mode, the receiving relay accepts a GOOSE message that is flagged with the simulation bit=true instead of receiving an actual GOOSE message.

The demonstration has proven that using the IEC 61850 Edition 2 test mode and simulation feature easily allows for the isolation of the equipment under test to be performed from the central engineering computer. An available access point at the process bus Ethernet switch allows easy access to connect the test equipment. Injection of simulated sampled values using the test set triggered the protection function as expected. All related events, alarms, and measurements were automatically collected, which allowed for efficient documentation and conclusion of the test.

Compared to the traditional isolation and testing using test switches and hardwired test set, the solution based on IEC 61850 allowed for more efficient testing, plus quality documentation without any extra effort. It also is a very safe solution compared to the traditional approach, as the testing engineers do not have to deal with current circuits and hardwired connections. The solutions based on IEC 61850 have even further potential application: technically, it would be possible to conduct all of these tests from a remote location, fully exploring the benefits of process bus and IEC 61850 Edition 2 testing and simulation features.

Some care needs to be taken for the block mode. Initially, there was some confusion concerning the behavior when an IED is in block mode. Further investigation clarified the issue. As IEC 61850 Edition 2 was not clear, a tissue[13] has been approved clarifying the behavior to eliminate misinterpretation. So, it is important to ensure that IEDs not only adhere to IEC 61850 Edition 2 but that they also address the latest tissue concerning blocking. During such a solution, engineering care has to be taken to ensure proper implementation of the block bit inside the IEDs application. Different vendors and products will have slightly different approached on how this information is connected to the desired logical nodes. In the case of the tested Vendor 2 670 series product, any output linked to primary equipment-related Logical Nodes such as XCBR was, per default, linked to the blocking information. Whereas, the blocking of other outputs would require a connection of the blocking signal of the relevant LN in the design stage.

The "successful operation" feedback using the OR functional constraint OpRcvd and OpOk, which allows closed loop feedback of an isolated test scenario without controlling an output signal, may not be supported by every IEC 61850 Edition 2 compliant device, as it is an optional feature. In this project test setup, it was only possible with the REC670.

2.8.4 Use Case 3: Breaker failure scheme

2.8.4.1 Problem statement

With the use of IEC 61850 communications, traditional copper wiring can be replaced by GOOSE message exchange between different IEDs to perform certain actions. One example is in the use of breaker failure signals to the neighboring circuit breaker IED via GOOSE messaging. When a circuit breaker fails to operate and isolate a fault within the feeder, the feeder relay needs to send a breaker failure initiate signal to the bus protection relay in order to isolate the bus from the faulty section. While the industry has extensive experience with the performance of this feature using the hardwiring of IEDs, the use of GOOSE messaging has not been widely exercised. Despite the advantages, using GOOSE messaging for this purpose is relatively new, and the performance restrictions are not well documented. Therefore, it is imperative to investigate the performance of a GOOSE-message-based breaker failure scheme before wide deployment.

2.8.4.2 Objective

The objective of Use Case 3 was the performance evaluation of a GOOSE-message-based breaker failure scheme. The primary evaluation criteria were speed and reliability. The demonstration for Use Case 3 exhibited the effectiveness of GOOSE-messaging for breaker failure implementation.

2.8.4.3 Description

In Use Case 3, various tests were used to evaluate the performance of a GOOSE-message-based breaker-failure scheme. The scheme used bus protection relays REC670 and SEL487 to perform tripping of all bus breakers (if a breaker failure of one of the feeder breakers is detected). In such an instance, all feeder relays, including the tie protection relay, will send a signal via IEC 61850 GOOSE message that a trip command was issued to the breaker.

The logic starts the breaker failure timer upon the reception of this signal (if the current through the breaker is above a certain level). The breaker failure timer is set with a 150-ms time delay. This confirms

[13] Tissue is a Technical Issue – nomenclature used in the IEC 61850 standards community

that the breaker has actually failed and has not opened as required. The 150-ms time delay takes the following delays into consideration – measured from the moment of detection of the fault by the relay:

- 1-cycle trip-propagation time
- 3-cycle breaker-opening time
- 3 cycle relay-reset time
- 2-cycle safety margin

The current detectors are non-directional, overcurrent elements that monitor phase and ground (or residual) current. It is good practice to set the phase fault detector element above 120 percent of maximum load, where possible. If the phase current detector cannot be set above load, a negative sequence element may be used in addition. This will prevent misoperations due to incorrect breaker-failure initiations during commissioning or maintenance testing. Figure 2-27 illustrates the breaker failure logic.

Some applications have low fault currents that are difficult to reliably detect using the current detectors. Typical examples of these situations are:

- Transformer faults
- Weak or zero in-feed trips
- Overvoltage trips
- Circuit breaker restrike

In these applications, the breaker failure scheme can be modified to use a breaker "52a" contact in parallel with the current detector. With this change, both the dropout of the current detector and the opening of the 52a contact indicate an open breaker, and so are used for supervision.

The 52a breaker contact was not used for this demonstration, as it was assumed that the fault current is always higher than 120% of load current. It should be noted that extending the beaker failure scheme would not require any additional wiring and could be performed by reconfiguring the existing IEDs and enhancing the logic.

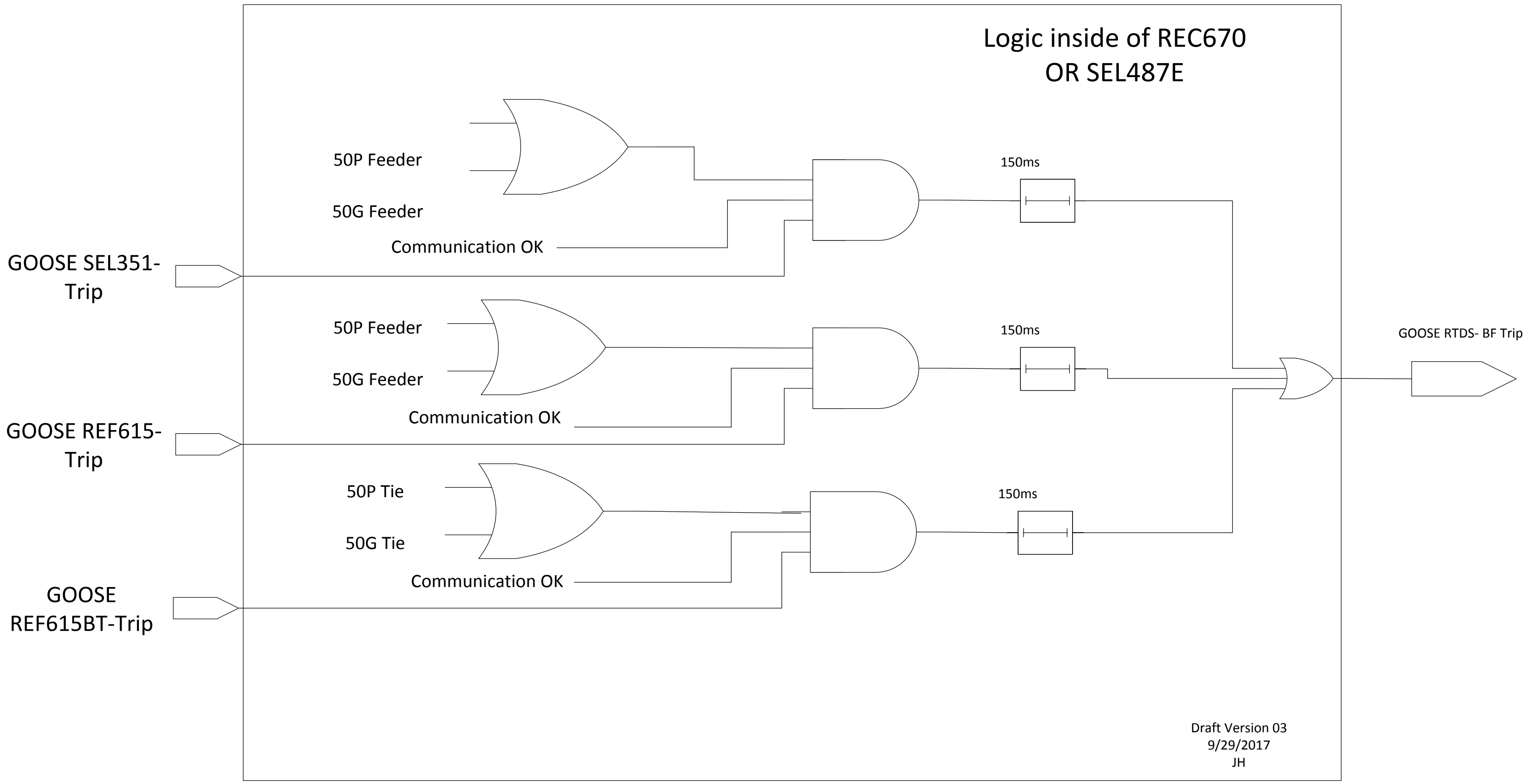

Figure 2-27. Breaker failure logic

2.8.4.4 Test cases and results

The selected test cases demonstrated the correct breaker failure functionality, including under extreme conditions (Table 2-20).

Table 2-20. Breaker failure scheme test cases and results

Case	Test Case	Description	Result of Wired Design	Result of IEC 61850 Design
1	Feeder relay issues correct operation and breaker opens	• Close target circuit breaker • Inject overcurrent into target IED by A-G Fault on Bus 301 • Instant Trip CCR2 CB2 by SEL351 & REF615 in substation • Check correct operation • Capture measurements and events using DFR	No Breaker Failure operation was issued as expected.	No Breaker Failure operation was issued as expected.
2	Feeder relay issues correct operation and breaker fails (GOOSE)	• Close all breakers • Isolate breaker trip command of target breaker/IED • Inject overcurrent into target IED by A-G Fault on Bus 301 • Breaker failure GOOSE message is sent to bus IED • All surrounding breakers are tripped. Instant Trip by SEL351 & REF615 in substation but breaker CCR2 CB2 fails. BF trip by REF670 and SEL487E after 150 ms • Check correct operation • Capture measurements and events using DFR	Correct Breaker Failure operation after 210 ms	Correct Breaker Failure operation after 210 ms
3	Feeder relay issues correct operation and breaker fails but no BF on temporary fault	• Close all breakers • Isolate breaker trip command of target breaker/IED • Inject overcurrent into target IED by A-G Fault on Bus 301 for 100 ms • Instant Trip by SEL351 & REF615 in substation but breaker CCR2 CB2 fails. No BF trip. • Check correct operation • Capture measurements and events using DFR	No Breaker Failure operation was issued as expected.	No Breaker Failure operation was issued as expected.

Case	Test Case	Description	Result of Wired Design	Result of IEC 61850 Design
4	Feeder relay issues correct operation and breaker fails but no breaker failure initiate is send due to interrupted communication	• Close all breakers • Isolate breaker trip command of target breaker/IED • Inject overcurrent into target IED by A-G Fault on Bus 301 • Breaker failure GOOSE message is not sent to bus IED due to interrupted communication • Alarm of failed communication is issued • Check correct operation • Capture measurements and events using DFR	A failed wire connection used for breaker failure initiate can cause major outage if not detected before needed	Alarm of failed communication link allows for repair of connection before it is needed.

Problem
Improved result

2.8.4.5 Findings

The demonstration showed that a breaker-failure scheme can easily be implemented with the information available in the IEC 61850 system without the need of wiring.

In addition, Use Case 3 demonstrated that the breaker-failure scheme based on IEC 61850 GOOSE communication is more reliable than a wired implementation, as all communication links are continuously monitored. Any communication interruption will be alarmed and can be used to locate and resolve the problem. Wired breaker-failure implementation occasionally failed due to connection problems that were not detected before the signal was needed.

2.8.5 Use Case 4: Automatic transfer scheme

2.8.5.1 Problem statement

Automatic transfer schemes are used to maintain continuity of supply during the transfer of a bus from one power source to an alternate power source. A proper transfer system must be designed in such a way that it operates quickly and prevents damage to loads connected to the transferred bus. In cases of losing one of the main in-feeds (e.g., due to an accidental breaker operation at the 69-kV level or a transformer fault), the dead bus can be energized and fed via the bus tie. Ideally, the outage of one of the main supply transformers can trigger a load transfer to the other in-feed. However, before the bus tie can be closed to complete the transfer, certain criteria must be checked to ensure safe and reliable load transfer. The criteria become more important in the presence of DER in distribution circuits.

2.8.5.2 Objective

During the project, the implementation of an automatic transfer scheme using IEC 61850 GOOSE messages was demonstrated. Circuit breaker positions, voltage measurements, fault indications, and so on, were transmitted via IEC 61850 communication protocol and processed by a control logic that was implemented in one of the substation IEDs (Vendor 2 REC670). In a traditional power-source transfer scheme, the aforementioned information is normally exchanged via a hardwired connection between the different components. In Use Case 4, however, it was demonstrated how GOOSE messages can be used for this purpose.

The main objective of Use Case 4 was to demonstrate the benefits of using IEC 61850 GOOSE messages for the implementation of a fast and reliable power-source transfer scheme. These benefits include the following:

- The scheme can be easily changed and extended. All necessary information required by the scheme logic is available in an IEC 61850-based substation, and this information can be accessed without the need for additional wiring. Any command or action can be sent to any IED connected to the IEC 61850 system (including the IED located on the feeder, as in this demonstration).

- All communication links are continuously monitored. This improves the reliability of the transfer scheme implementation. Any communication interruption will be alarmed, and this alarm can be used to activate predefined actions in the logic to prevent undesired behavior of the transfer scheme.

2.8.5.3 Description

SDG&E uses the Main-Tie-Main bus configuration in order to have redundant sources available for feeder loads. Under normal conditions, the load is distributed in approximately equal amounts between the two alternative sources. During a planned or unplanned outage of one of the sources, the load is automatically transferred to the remaining source if certain conditions are fulfilled.

Before an automatic transfer sequence is performed, the control logic of the automatic transfer scheme typically processes the following information:

- Breaker status
- Protection equipment operations and status
- Voltage levels
- Control Switch inputs

For the demonstration of Use Case 4, a slow transfer scheme with residual voltage monitoring (as shown in Figure 2-28) was selected.

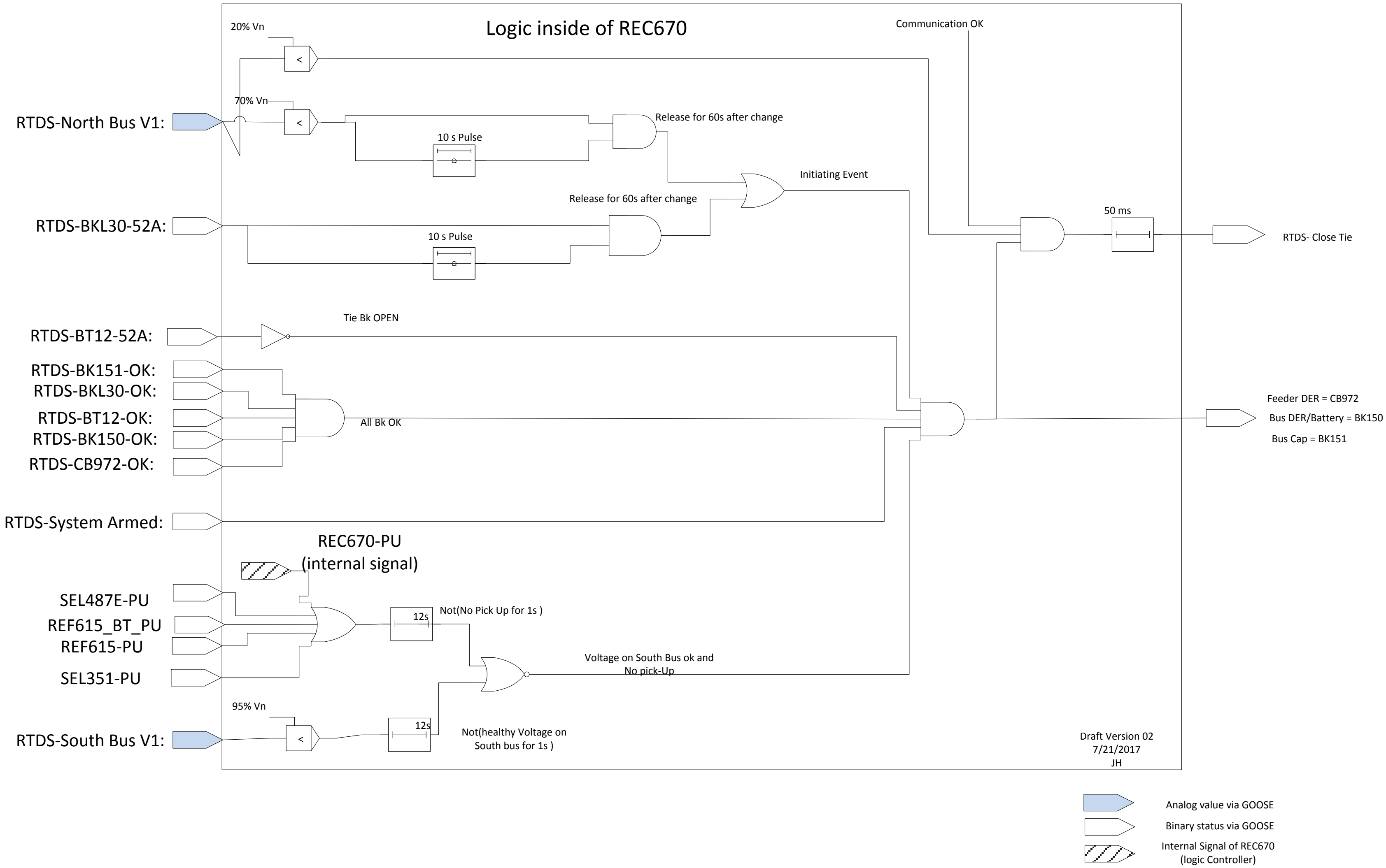

Figure 2-28. Automatic transfer scheme logic

The automatic transfer scheme is triggered by either the disappearance of the measured north-bus voltage (<70% $V_{Nominal}$) or by the opening of the low-side transformer breaker (BKL30). Before the tie breaker is closed, the following conditions must be fulfilled within a time window of 10 s:

- The North Bus residual voltage generated by the inductive load declines to below 20%
- All breakers are operational
- Tie breaker is open
- The scheme is armed
- There was no protection pickup for the last 12 s
- The south bus voltage is healthy (>95% VNominal)

After all conditions are met, a transfer will be initiated. Before the tie breaker can close, the following occurs:

- A transfer trip is sent to the DER connected on the feeder
- The North Bus cap bank is disconnected
- The battery connected to the North Bus is disconnected

It should be noted that the focus of Use Case 4 was not so much on the actual auto transfer scheme logic, but rather on the implementation of the transfer using GOOSE messaging instead of wired connections.

2.8.5.4 Test cases and results

The selected test cases should demonstrate that the automatic transfer scheme performs correctly for all situations, so that:

- For all source interruptions, a correct (fast and reliable) load transfer is expected
- For all bus and feeder faults that result in a bus operation, no load transfer is expected

Table 2-21. Automatic transfer scheme test cases and results

Case	Test Case	Description	Results IEC 61850 Design
1	HV side North Bus transformer breaker BKH30 opens	- All transformer breakers (BKH30, BKL30, BKH32, BKL32) as closed and North Bus and South Bus are energized - Disconnect source by opening HV breaker of North Bus transformer T2 (BKH30) - Automatic transfer scheme is started - Check correct operation - Capture measurements and events using DFR	Scheme transferred correct after 130 ms
2	MV side North Bus transformer breaker BKL30 opens	- All transformer breakers (BKH30, BKL30, BKH32, BKL32) as closed and North Bus and South Bus are energized - Disconnect source by opening MV breaker of North Bus transformer T2 (BKL30) - Automatic transfer scheme is started - Check correct operation - Capture measurements and events using DFR	Scheme transferred correct after 144 ms

Case	Test Case	Description	Results IEC 61850 Design
3	South Bus is de-energized when North Bus Transformer Breaker opens	- South Bus High Side breaker BKH32 is open, all other transformer breakers (BKH30, BKL30BKL32) as closed and only North Bus is energized - Disconnect source by opening MV breaker of North Bus transformer T2 (BKL30) - Automatic transfer scheme is not started - Check correct operation	Scheme did not initiate a load transfer (correct operation)
4	Tie breaker is already closed when HV North Bus breaker opens	- All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized - Tie breaker (BT12) is closed -Disconnect source by opening HV breaker of North Bus transformer T2 (BKH30) -Automatic transfer scheme is started -Check correct operation	Scheme did not initiate a load transfer (correct operation)
5	Close-In feeder fault	-All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized -Apply close-in feeder fault (on Bus 301) -Automatic transfer scheme is not started -Check correct operation	Scheme did not initiate a load transfer (correct operation)
6	North Bus de-energization after Bus Fault	-All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized -Apply 3-phase fault on North Bus -Automatic transfer scheme is not started -Check correct operation	Scheme did not initiate a load transfer (correct operation)
7	Breaker BKH30 opens and communication from tie relay is interrupted, everything else is normal	-All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized - Tie breaker (BT12) is closed -Interrupt Communication and open BKH30 - Check correct operation	Scheme did not initiate a load transfer (correct operation) Improvement of reliability as GOOSE message is monitored

Improved result

2.8.5.5 Findings

The demonstration showed that an automatic transfer scheme can easily be implemented with the information available in the IEC 61850 system without additional wiring. The system has access to all data provided by the IEDs integrated in the IEC 61850 system. In this demonstration, IED's located on the feeder were also integrated, and therefore, transfer trip commands to the DER located on the feeder had been realized. Any scheme change or extension can be performed by editing only the scheme logic and configuration of IEDs. No new wiring is required. Additionally, Use Case 4 demonstrated that an automatic transfer scheme based on IEC 61850 GOOSE communication is more reliable than a wired implementation, as all communication links are continuously monitored. Any communication interruption is alarmed and can be used to activate predefined actions in the logic to prevent undesired behavior of the transfer scheme.

2.8.6 Use Case 5: Improved protection coordination

2.8.6.1 Problem statement

Short-circuit faults on distribution circuits are typically detected and isolated by inverse-time overcurrent protective devices. The coordination between overcurrent elements installed along the distribution feeder and those located on the substation is achieved via time coordination (following minimum recommended margins). However, this traditional approach may result in long feeder-relay operating times if the fault occurs near the substation. This is particularly problematic for faults near the substation with high fault currents as they can be dangerous and cause major damage if not cleared quickly. To mitigate this problem, it is common practice to use instantaneous overcurrent elements in addition to the traditional approach. Coordination with instantaneous overcurrent elements on the feeder can be very challenging and cannot always be guaranteed.

For example, on circuit CCR2 of the Creelman substation, the instantaneous element of the feeder protection was set to 7600 A for the phase element and 3360 A for the ground element. This leads to an uncoordinated, fast fault clearing for fault currents of 9600 A directly beyond the recloser 26R relay. At present, SDG&E must accept the uncoordinated operation in order to limit the fault current energy (I^2t).

2.8.6.2 Objective

During the project, it was demonstrated how protection coordination can be improved when an IEC 61850-based communication system is utilized. For example, to determine a faulty section and clear the fault in a faster, coordinated way, the protection pickup signal can be communicated between relays via IEC 61850 GOOSE messaging. Additionally, for high resistive faults, the sensitivity of the protection scheme can be increased to result in faster operation.

With the increase of DER, bi-directional protection elements may need to be utilized for selective fault clearance. Figure 2-29 presents the fault currents and relay settings on feeder.

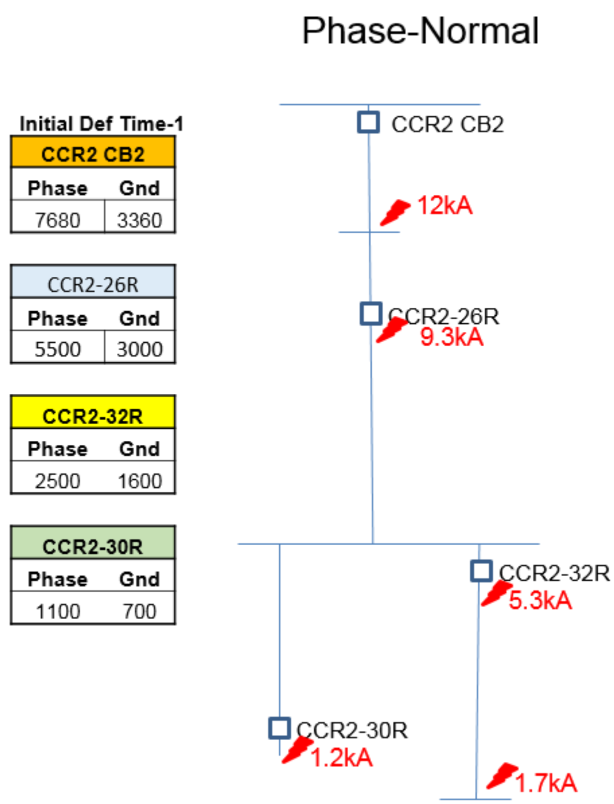

Figure 2-29. Fault currents and relay settings on feeder

Other applications for the utilization of IEC 61850 GOOSE message exchange between feeder and substation relays are as follows:

- In the presence of large-scale DER on the distribution circuit, the status of a feeder circuit breaker (CB) can be used to send a direct transfer trip (DTT) signal to the DER and disconnect it upon CB opening. This can improve both the security and dependability of the anti-islanding protection. The IEC 61850 can help expedite the process of DER disconnection by sending a high-speed DTT signal and by confirming that the DER has ceased energization.
- During the hazard season and/or circuit reconfiguration, the electric distribution operation (EDO) group can send remote signals to disable auto-reclosing mechanisms and/or to change the protection settings group in a protective device(s).

2.8.6.3 Description

Use Case 5 demonstrated the protection advantages of using GOOSE messaging to exchange information between the feeder and the substation relays. A GOOSE message that signals the pickup for a fault was sent from feeder recloser 26R to block the substation feeder relay from fast operations. The feeder relay in the Creelman substation had an additional sensitive instantaneous ground and phase element activated that would be blocked via a GOOSE message from the downstream recloser 26R whenever the recloser picked up with a ground or phase element.

The logic used inside the substation feeder relay (as shown in Figure 2-30) required recloser relay 26R to send each signal as active-low and active-high simultaneously. Only if the receiving relay received a signal as active-low and active-high, would it process and block or unblock the sensitive instantaneous elements. This was done for security reasons so as not to rely on a single signal for this critical protection action.

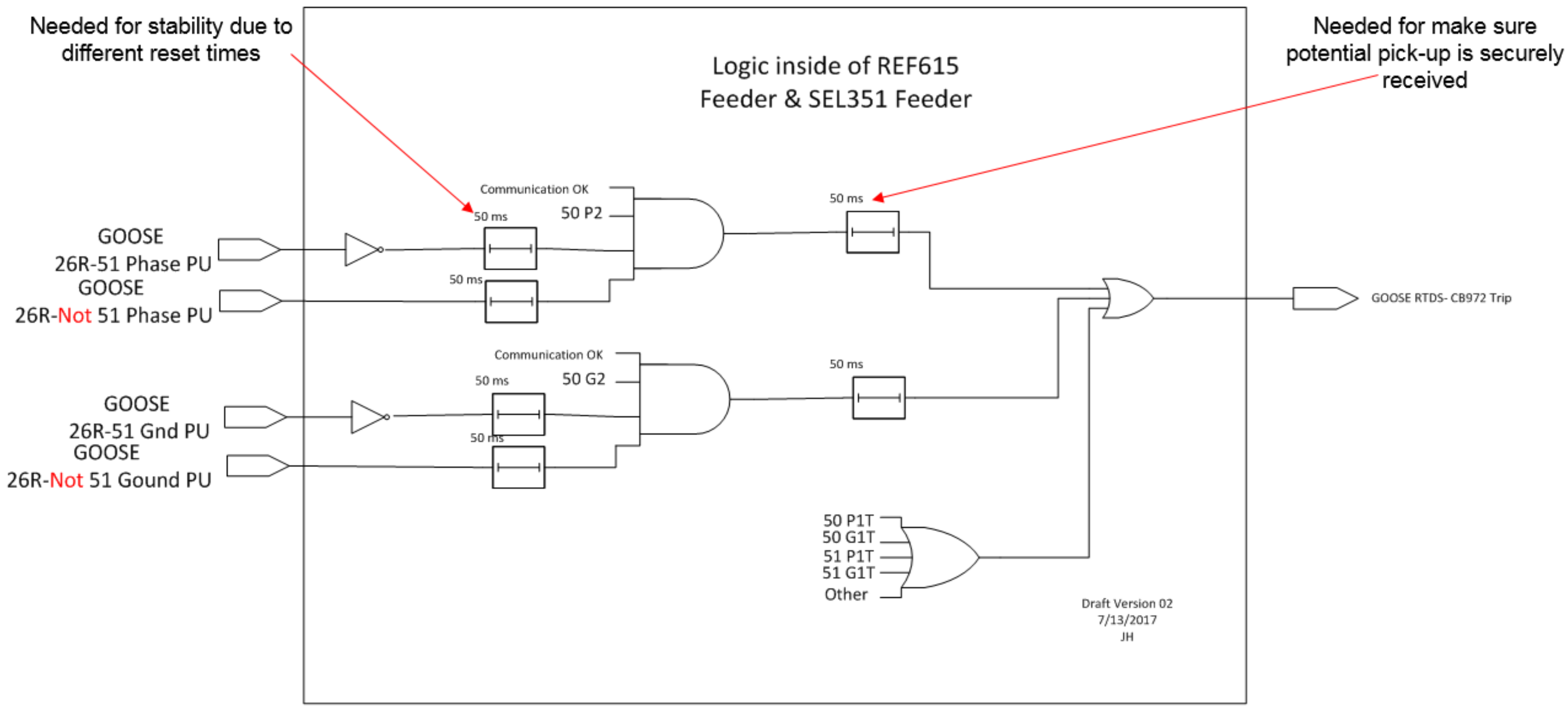

Figure 2-30. Blocking logic and trip logic of feeder relay at Substation C

The delay timer in the logic are needed to assure correct operation when both relays have different pickup operation speeds, and also to accommodate the signal propagation time.

The pickup settings for the new, additional, GOOSE-signal-controlled instantaneous elements of the substation feeder relay were 1500 A for the phase element and 500 A for the ground element. The pickup settings must be coordinated with the settings of the downstream recloser relay, so that the recloser relay will always pick up for the downstream fault whenever the sensitive element of the substation relay picks up. The 51 elements of the recloser relay were set to 800 A for the phase element and 400 A for the ground element. Any load connected between the recloser and the substation relays must be considered for the phase-element setting.

Table 2-22. Selected settings for the overcurrent relays

Sub IR	CCR2			CCR2-26R					
				PROFILE 1			PROFILE 3		
	NORMAL			NORMAL			FAST/SENSITIZED		
		Phase	Gnd	2	Phase	Gnd		Phase	Gnd
Initial Trip Settings									
Min Trip Pick Up Amps		800	**500**	Enabled	**800**	**400**	Enabled	**705**	**35**
TCC for Initial, Test, & Closing Profiles		CO-8	CO-8		SEL U2	SEL U3		SEL U2	SEL U3
Time Mult (Time Dial)		2.5	**6.5**		1.40	6.20		1.40	6.20
Min TCC Response Time (sec)					0.05	0.05		0.05	0.05
Time Adder					0	0		0	0
Disc Reset Type (EM or DT)				E/M	calc	calc	E/M	calc	calc
Low Cut-off (Amps)					N/A	N/A		N/A	N/A
Initial Def Time-1		**11160**	**7800**		**6360**	**3000**		705	35
Initial Def Time-2 (with GOOSE Application)		**1500**	**500**		**NA**	**NA**		5500	3000

2.8.6.4 Test cases and results

For the demonstration, faults were applied on different locations along the feeder, and the protection response was observed. The close-in faults were all simulated with a 5 ohm resistor to limit the fault currents to a level that could be injected into the relays with the available current amplifiers.

Table 2-23. Use cases developed for Phase 3 testing

Test #	Test case	Description	Results Conventional Design	Results IEC 61850 Design
1	Substation bus fault	• South Bus and North Bus are energized, and all feeder breakers are closed • Inject A-G Fault on North Bus • Busbar protection trips all bus breakers	Instantaneous bus fault clearing by bus differential relay	Instantaneous bus fault clearing by bus differential relay
2	Feeder close-in fault	• North Bus is energized, and target feeder is connected • Inject A-G Fault (with 5 Ohm) on Bus 301 • Feeder relay issues a trip instantaneously as it will not receive blocking signal from remote relay	Element 51 in the feeder relay cleared the fault after 1.5 s due to 1.6 kA fault current	Fast fault clearing after 60 ms by advanced protection scheme

Test #	Test case	Description	Results Conventional Design	Results IEC 61850 Design
3	Feeder end-of-line fault	• North Bus is energized, and target feeder is connected • Inject a B-G Fault on Bus 302 • Downstream IED trips and does not send unblock GOOSE message to feeder relay	Element 51 in the 26R recloser cleared fault after 1.2 s due to 1.6 kA fault current	Element 51 in the 26R recloser cleared fault after 1.2 s due to 1.6 kA fault current
3a	Feeder end-of-line fault	• North Bus is energized, and target feeder is connected • Inject a 3-pole Fault on Bus 302 • Downstream IED trips and does not send unblock GOOSE message to feeder relay	Element 51 in the 26R recloser cleared fault after 2.5 s due to 1.8 kA fault current	Element 51 in the 26R recloser cleared fault after 2.5 s due to 1.8 kA fault current
3b*	Feeder end-of-line fault	• North Bus is energized, and target feeder is connected • Inject a 3-pole Fault on Bus 302 (without additional resistor) • Downstream IED trips and does not send unblock GOOSE message to feeder relay	Instantaneous fault clearing by 26R recloser and CCR2 relay due to 9.3 kA fault current (coordination problem)	Instantaneous fault clearing of 26R relay due to 9.3 kA fault current. Sensitive element of CCR2 relay was blocked, and instantaneous element was well coordinated
4	Resistive Feeder close-in fault	• North Bus is energized, and target feeder is connected • Inject A-G resistive (20 Ohm) Fault on Bus 301 • Feeder relay issues a trip instantaneously as it will not receive blocking signal from remote relay	Element 51 in the feeder relay cleared the fault after 3.5s due to 830 A fault current	Fast fault clearing after 80 ms by advanced protection scheme
5	Feeder end-of-line fault	• North Bus is energized, and target feeder is connected • Inject B-G Fault on Bus 305 • Downstream IED trips and does not send unblock GOOSE message to feeder relay	Fault cleared by 32R recloser	Fault cleared by 32R recloser

Problem
Improved result

* Test Case 3b has only been theoretically evaluated. The available amplifier did not allow the replay of a 9.6-kA fault current (60 A secondary).

2.8.6.5 Findings

Use Case 5 demonstrated that IEC 61850 communication provided the following benefits:

- Enhanced operation of feeder protection: If a fault takes place between the feeder breaker and the downstream protective device, the fault can be quickly located through communication between the feeder relay and the downstream IED such that the operation of the feeder relay will be expedited for high resistive faults and close-in faults that can potentially damage the power equipment.
- Improved anti-islanding protection of DER: During a fault on the distribution substation, all the feeder breakers will open to isolate the fault. This will cause distribution feeders with DER to form a potential island. In such situations, direct transfer trips (DTTs) will be sent to all DER within the islanded feeder to ensure anti-islanding protection for all substation faults.
- Improved reclosing/relaying operation: If the circuit topology is changed, or during fire hazard season, the EDO department can block the reclosing mechanism on some IEDs and/or change the protection settings group of some protection IEDs. With appropriate control logic implemented in the substation controller, IEC 61850 communication can be used to perform these tasks more effectively.

2.8.7 Use Case 6: DER control mode change

2.8.7.1 Problem statement

Large-scale integration of DERs and high penetration of variable generation units such as PV systems cause adverse impact on the power quality and circuit voltages. In many cases, it is required to control active and reactive power of large DER output actively and frequently to manage voltage levels across the circuit or to control large amounts of reverse power flow when the circuit is under light-load conditions. In these cases, the control modes of the DERs may need to be changed and this use case demonstrates how IEC 61850 can be used to implement DER Control Mode Change (DER-CMC).

2.8.7.2 Description and objectives

This use case incorporates communications to DERs on distribution systems as part of the substation automation schemes (substation based controls) or through SCADA/DMS control signals that are sent through substation automation. The control modes considered in this study include:

- Remote active power curtailment/settlement and reactive power adjustment (1)
- Remote power factor (pf) control methods of inverters (2)
- Droop control modes that adjust reactive power setpoint based on a linear droop curve that determines the reactive power setpoint (3)
- DER idle mode, where DER is connected to the system, but has no interaction or power exchange with the grid (4)

In this use case, the IEC 61850 GOOSE messaging will be used mainly for communications to DER units that support this protocol. If the DER does not support the IEC 61850 protocol, a gateway is used as the protocol converter to enable communication with the DER supporting conventional communications.

Mode change or setting change and exchange of information on measurements and/or status from the DER location and operation will be transferred to the DER through GOOSE messages.

As part of this use case, communication with the battery at the ITF parking lot was examined using an additional cell modem and gateway installed at the site and accessed from ITF. The gateway device supports protocol conversion at the site. The logic diagram of this use case is shown in Figure 2-31. Logic diagram of the DER-CMC use case.

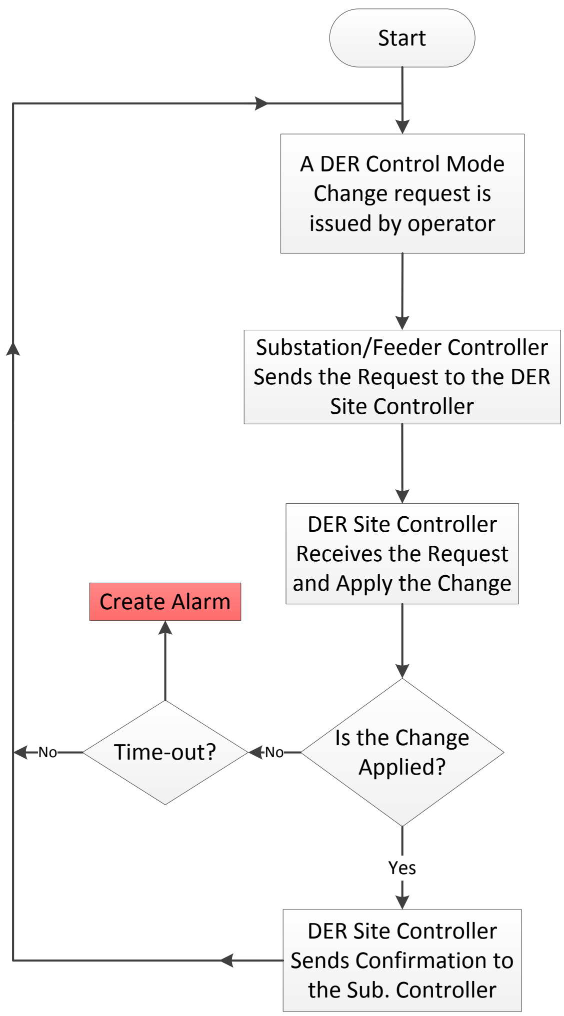

Figure 2-31. Logic diagram of the DER-CMC use case

2.8.7.3 Test cases and results

As discussed in previous sections, the purpose of this use case is to verify that the DER control mode and parameters can be modified/changed remotely through IEC 61850 communications with the DERs. For this purpose, the operator will change the DER control mode and/or parameters through GOOSE/MMS commands/setpoints. The commands/setpoints are issued from the HMI to the DER, and the results (DER responses) are collected.

lists major test cases for this use. Although all tests have been conducted, only the results of a selected number of cases will be presented and briefly discussed in this section due to space limitations. . The results of additional tests cases are provided in Appendix D. Figure 2-32 identifies the locations of the DER devices that are referenced in the test cases.

Table 2-24. DER-CMC test cases

Case	Test Conditions	Description	Remark
1.1	Substation controller requests a control mode change from Local/Droop to remote P-Q adjustment mode (3-->1)	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.2	Issue P/curtailment command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.3	Issue Q command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.4	Issue pf command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.5	Substation controller requests a control mode change from remote P-Q mode to remote P-pf adjustment mode (1→2)	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.6	Issue P/curtailment command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.7	Issue Q command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.8	Issue pf command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.9	Substation controller requests a control mode change from remote P-pf mode to Local/Droop mode (2-->3)	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.10	Issue VQdroop (droop coefficient) command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.11	Issue VLband (low setpoint of the voltage band) command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.12	Issue VHband (high setpoint of the voltage band) command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.13	Substation controller requests a control mode change from Local/Droop mode to Idle mode (3-->4)	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
DER Control Modes: (1) Remote P/Q Adjustment (2) Remote P/pf Adjustment (3) Local (V-Q Droop) (4) Idle			

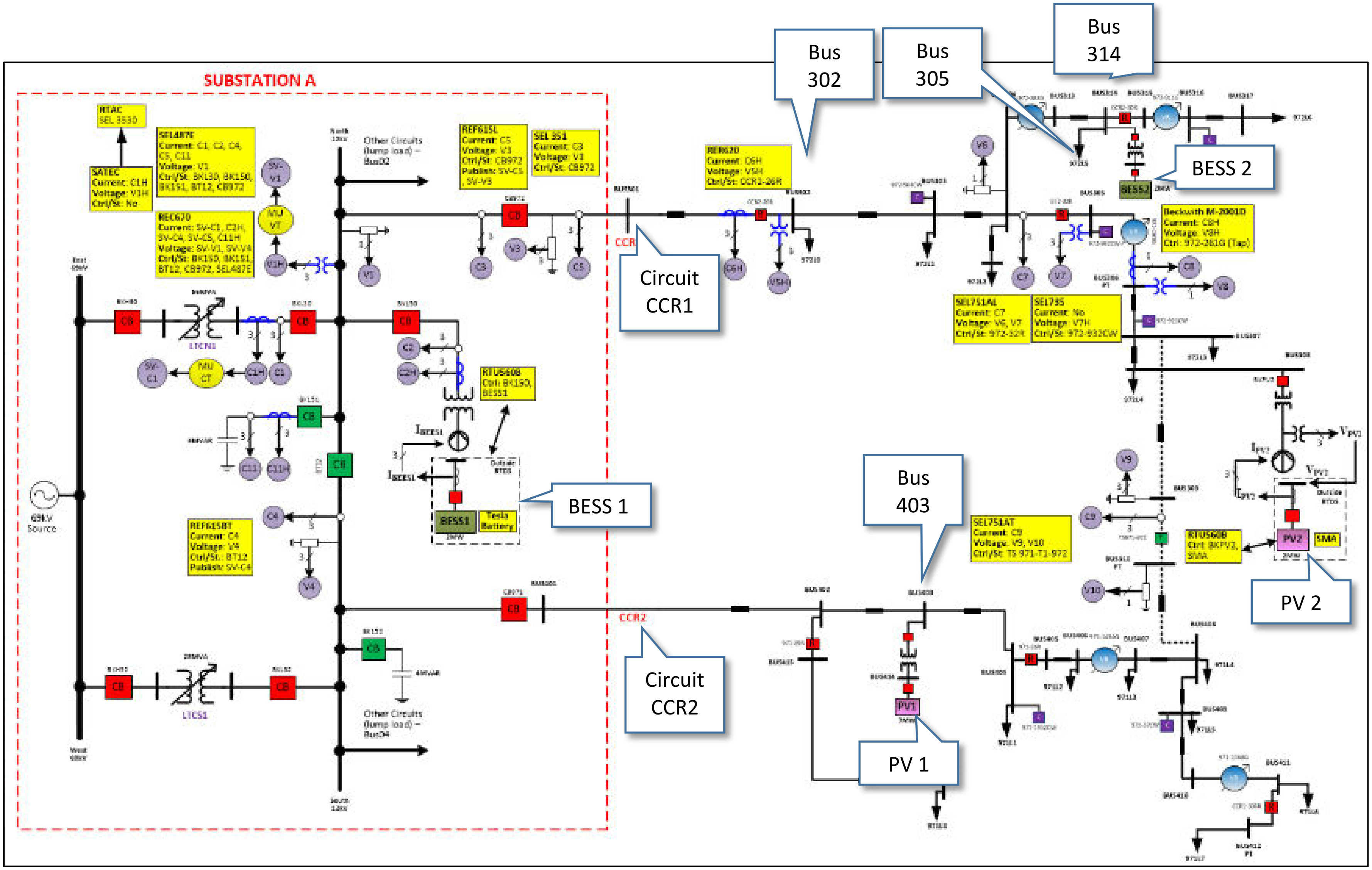

Figure 2-32. Test system SLD highlighting DER locations and circuit and bus identifiers

2.8.7.3.1 BESS 1

As discussed earlier, an RTU is used as a gateway between BESS 1 and substation gateway to operate as a protocol converter. This is mainly due to the fact that the existing DERs available in the market do not support IEC 61850 communication. For example, the BESS used in this project was supporting Modbus for the communication. Further, the battery has limited capability in supporting all control modes defined previously in Table 2-24. BESS2 is only supporting control mode 1 (Remote P and Q adjustment) and control mode 4 (idle).

Figure 2-33 shows the response of BESS 1 to the following sequence of control commands:

(0). The battery control mode is changed from 4 to 1
(1). The battery active power is changed from zero to 1 MW
(2). The battery reactive power is changed from zero to 0.5 Mvar (while P_{SP}=1 MW)
(3). The battery active power is changed from 1 MW to –0.7 MW
(4). The battery reactive power is changed from 0.5 Mvar to –0.5 MW
(5). The battery control mode is changed from 1 to 4

All control commands (mode and parameter change) are transferred to the Battery gateway (RTU) through IEC 61850 (GOOSE) communication. More specifically, a GOOSE message is issued from the substation gateway to the battery RTU located at the battery site. The RTU then converts the command from GOOSE to the protocol supported by the battery (in this case Modbus).

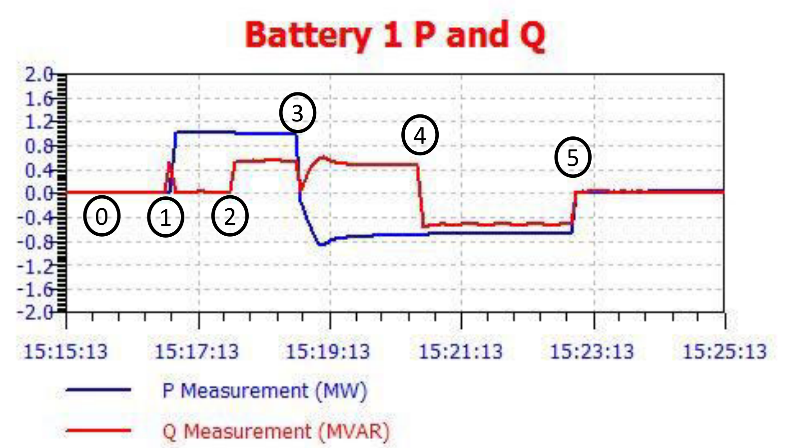

Figure 2-33. Response of the Battery to a sequence of control commands

2.8.7.3.2 PV 1

This case investigates changing control mode and parameters of PV 1 simulated in the RTDS. Therefore, all of the GOOSE commands are sent from the RTAC to the RTDS. Figure 2-34 shows the response of PV 1 to a sequence of control commands as follows:

(0). The PV control mode is changed to 1
(1). The PV active power is curtailed to 2 MW (from 3.5 MW)

(2). The PV reactive power is changed from zero to 1 Mvar (while P=2 MW)
(3). The PV reactive power is changed from 1 Mvar to –1 MW
(4). The PV control mode is changed from 1 to 4

To evaluate the performance of the PV under other control modes, particularly Control Mods 2 (remote active power and power factor adjustment) and Control Mode 3 (V-Q Droop), further tests were executed. Figure 2-35 shows the response of PV1 to the second series of control commands as follows:

(0). The PV control mode is changed to 2 (P=3.5 MW)
(1). The PV power factor setpoint is changed from unity to 0.9
(2). The PV power factor setpoint is changed from 0.9 to 0.8
(3). The PV power factor setpoint is changed from 0.8 to –0.9
(4). The PV active power is curtailed to 2 MW
(5). The PV power factor setpoint is changed from –0.9 to –0.8

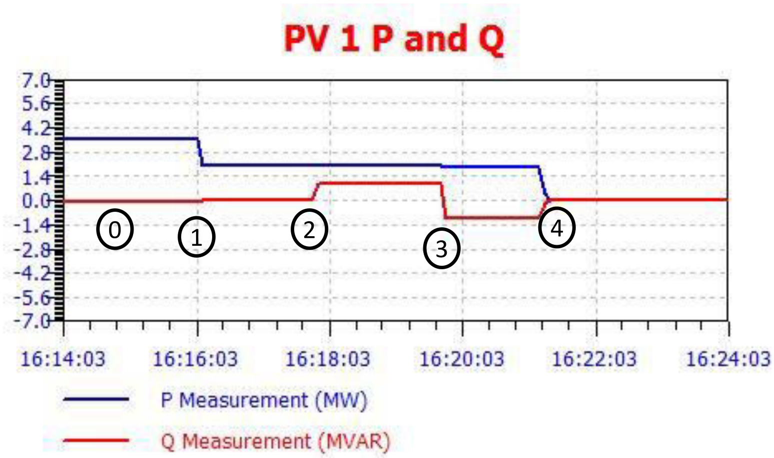

Figure 2-34. Response of PV1 to a sequence of control commands (Control Mode 1)

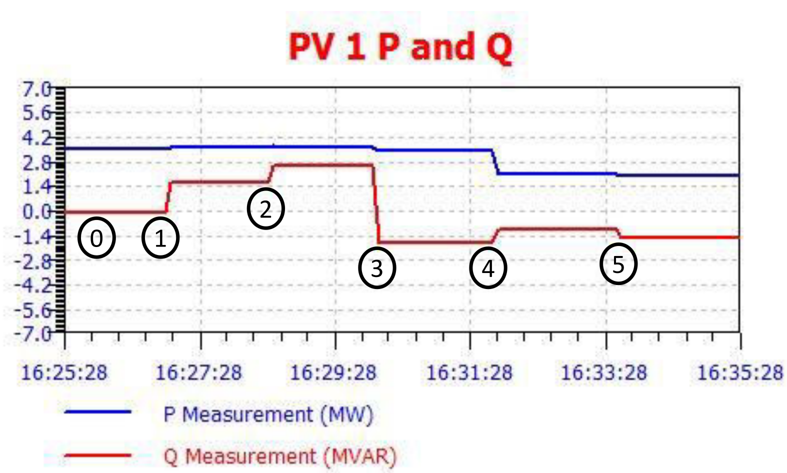

Figure 2-35. Response of PV1 to a sequence of control commands (Control Mode 2)

Finally, the following two figures present the performance of the PV inverter when it is switched to the V-Q droop control mode (Control Mode 3). Figure 2-36 and Figure 2-37, respectively, show the output power and terminal voltage of the PV, when the PV control mode is changed to V-Q droop. As indicated in Figure 2-36, the PV terminal voltage is higher than the droop high voltage threshold (V_{Hband}) prior to control mode change. Therefore, as soon as the control mode is changed to the V-Q droop, the PV reduces its output reactive power (see Figure 2-36) such that the voltage comes back to the permissible range[14] as highlighted in Figure 2-37.

The same sets of tests have been executed for all DERs under study (PV 1, PV 2, BESS 1, and BESS 2) to ensure their control modes and/or parameters can be adjusted through GOOSE messages from the substation RTAC. The result of those tests are provided in Appendix D – Additional Use Case results.

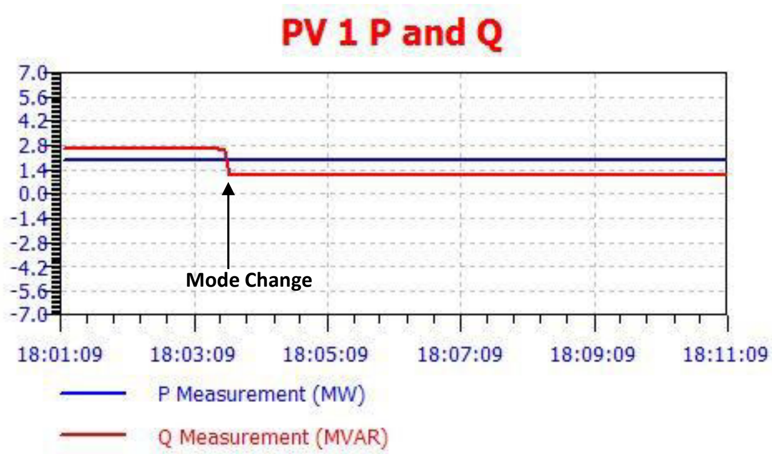

Figure 2-36. PV output power when its control mode changes to droop

[14] The permissible voltage range for each inverter can be remotely adjusted. For PV 1, this range is defined as (0.95pu, 1.05pu).

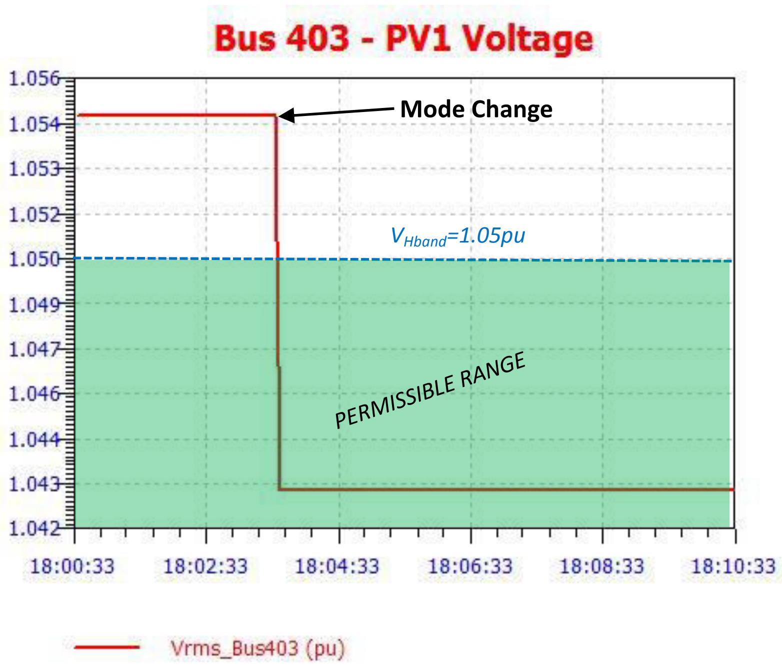

Figure 2-37. PV terminal voltage (average value) when the PV control mode changes to V-Q droop

2.8.7.4 Findings

The following is a list of findings for the DER-CMC use case:

- At the time the tests were conducted there were no commercially available DERs that provided native support for the IEC 61850 communication protocol. Although IEC 61850-7-420 intends to standardize the communications between DERs and other equipment, it is has still not been fully accepted by DER vendors.
- Since DER object models have not been fully developed/adopted, it is necessary to use a gateway between the DER and other equipment to enable peer-to-peer IEC 61850-based communication. The gateway should be capable of subscribing to both analog and digital values.
- In a peer-to-peer approach for DER-CMC, it is important to note which device is in charge of controlling the DER at each moment.
- The specific application and required speed of response will dictate which of the two IEC 61850 messages services, GOOSE or MMS, should be used for integrating DERs into the distribution circuit. For highly time critical application the peer-to-peer communications supported by GOOSE is the appropriate response. For less time critical applications either GOOSE or MMS are feasible options.
- The capabilities of DER devices differ and this impacts the feasibility of some applications. For example, the battery used in this study did not support V-Q droop mode, while the inverter did not support modifying the upper and lower voltage thresholds in the VQ-droop mode – both of which limited the functionality that could be implemented.

2.8.8 Use Case 7: Grid support using DERs

2.8.8.1 Problem statement

One of the key utility benefits claimed for large-scale deployment of DERs is that DERs provide grid-supporting capability such as reactive power management and voltage controls. Some control aspects of DERs are autonomous, meaning that it will happen automatically and locally in response to changes in the voltages and frequency of the grid. However, there are other grid-supporting features that would require coordination among multiple DER units within the same vicinity or in a coordinated fashion among all DERs that can provide the service. DERs will also need to be coordinated with the protection system to support the distribution grid effectively.

2.8.8.2 Description and objectives

The main objective of this use case is to evaluate inverter functionalities of DERs that are introduced to facilitate grid integration and high penetration levels. In this use case, communications through IEC 61850 will be used to control DERs or apply new setpoints for voltage and reactive power out of DERs. The control of reactive power and bus voltages is done centrally through the feeder controller. In particular, the feeder controller monitors the reactive power flow through the substation transformer and adjusts the reactive power setpoints of all DERs in order to meet the power factor target at the substation level.

The use case will also investigate IEEE 1547/Rule 21 functionalities of the inverter as it relates to grid support. In other words, it is investigated how the peer-to-peer communications among DERs and various protection equipment can enhance system performance under transient incident and grid fault.

2.8.8.3 Test cases and results

As described in Section 2.8.8.2, the goal of this use case is to effectively control DERs for supporting the distribution network under various operating conditions. In particular, voltage and/or reactive power support is of interest in this use case. It was studied how a distributed control using peer-to-peer communication among IEDs can help with effective utilization of DERs for the distribution grid support. Furthermore, the coordination between the system protection and low-voltage ride-through (LVR) capability of DERs is improved using the GOOSE messages between the protection relays and DER site controller. Several test cases were considered to evaluate the performance of this use case and to ensure enhanced operation of the system. Table 2-25 that follows lists major test cases considered for the GS-DER use case. Figure 2-38 presents a logic diagram of the GS-DER use case … Due to space limitations, only the results of a selected number of cases will be presented and briefly discussed in the following subsections. The results of all cases are provided in Appendix D – Additional Use Case results.

Table 2-25. GS-DER test cases

Case#	Test Conditions	Description	Remark
7.1	CCR1: Pload=1.0pu, PPV1=0.1pu CCR2: Pload=1.0pu, PPV2=0.1pu, PBESS1=0, PBESS2=0	High load profile (fix), low PV (fix)	Adjust Pf_target and evaluate the performance
7.2	CCR1: Pload=1.0pu, PPV1=0.2pu CCR2: Pload=1.0pu, PPV2=0.2pu, PBESS1=0 MW, PBESS2=-1 MW	High load profile (fix), low PV (fix)	Adjust voltage with DER and evaluate the performance
7.3	CCR1: Pload=1.0pu, PPV1=0.5pu CCR2: Pload=1.0pu, PPV2=0.7pu, PBESS1=0, PBESS2=0, QBESS2=–0 .5 MW	High load profile (fix), high PV (fix)	Adjust Pf_target and evaluate the performance
7.4	Repeat Case 7.1 and trip CCR2-932CW	High load profile (fix), low PV (fix)	Adjust Pf_target and evaluate the performance
7.5	Permanent SLG fault at Bus 305		BESS2 to provide LVRT, as appropriate
7.6	Permanent LLLG fault at Bus 305		BESS2 to provide LVRT, as appropriate
7.7	Permanent SLG fault at Bus 302		BESS2 to provide LVRT, as appropriate
7.8	Repeat Case 7.5, with CCR2-32R failing to operated properly		BESS2 to provide LVRT, as appropriate
7.9	Temporary SLG fault at Bus 305 (t=5cycles)		BESS2 to provide LVRT, as appropriate
7.10	Temporary LLLG fault at Bus 305 (t=3cycles)		BESS2 to provide LVRT, as appropriate
7.11	CCR1: Pload= 1pu, PPV1=0.2pu CCR2: Pload=1pu, PPV2=0.2pu, PBESS1=0 MW, PBESS2=–1 MW	High load profile (fix), high PV (fix)	Adjust Pf_target and evaluate the performance
7.12	Repeat Case 7.3 and trip Battery 1	High load profile (fix), high PV (fix)	Adjust Pf_target and evaluate the performance
NOTES: Light-Load Steady-State (LLSS) condition: No DER, Pload_CCR1=0.4pu, Pload_CCR2=0.4pu High-Load Steady-State (HLSS) condition: No DER, Pload_CCR1=0.95pu, Pload_CCR2=0.95pu			

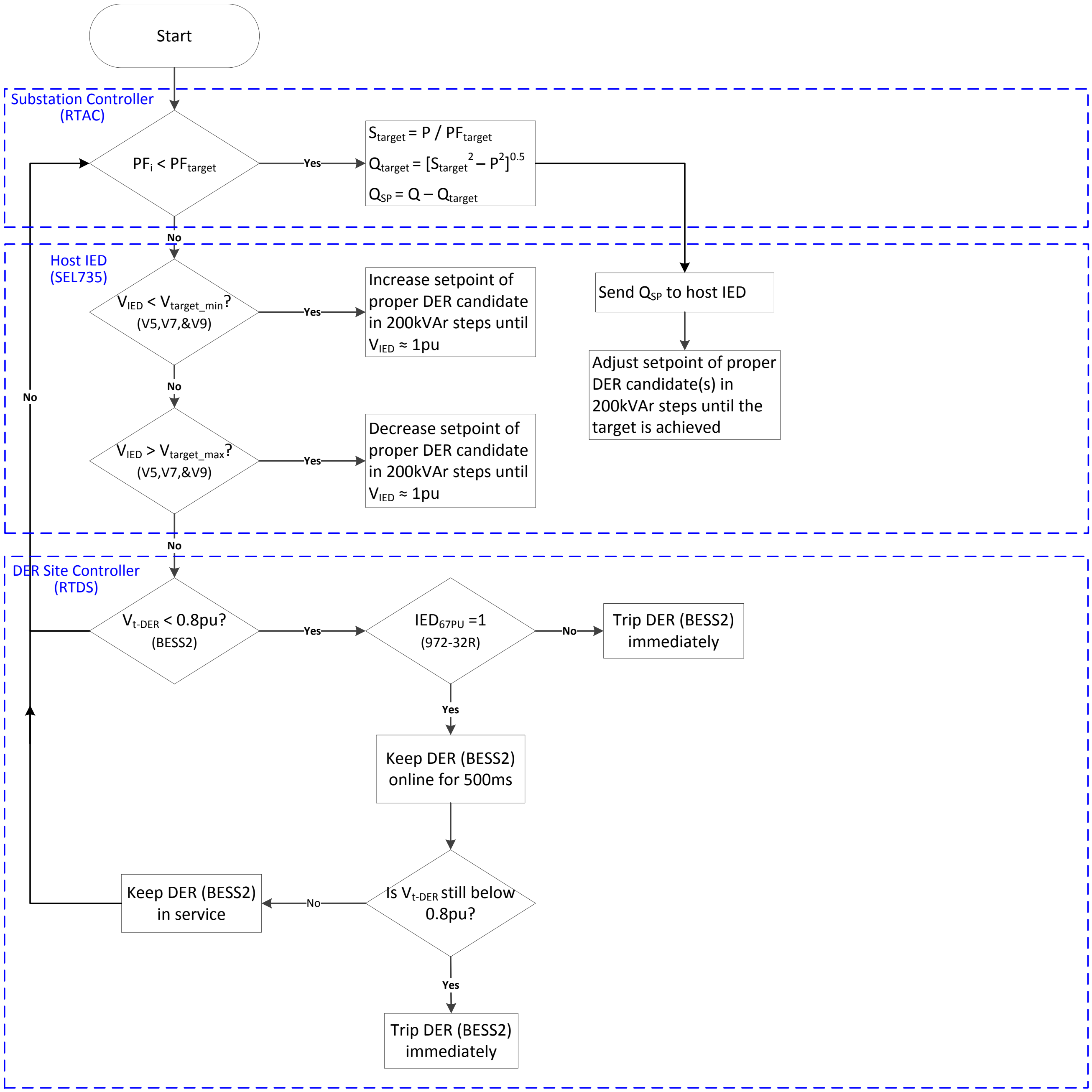

Figure 2-38. Logic diagram of the GS-DER use case

2.8.8.3.1 Case 7.4: Coordination between DER's LVRT and System Protection

This test focuses on the coordination between Recloser CCR2-32R and the feeder battery energy storage system (BESS 2). The location of these two devices were indicated previously in Figure 2-11. For a fault downstream of the recloser (e.g., Fault at Bus 305 in Figure 2-11), it is likely that the anti-islanding protection of BESS 2 operates in a non-coordinated manner with respect to the recloser. The unnecessary operation of the BESS 2 anti-islanding protection may even exacerbate the situation since DERs are supposed to provide LVRT support. Thus, it is desired that the recloser operates first for such fault cases to clear the fault. If the recloser fails to operate, then the BESS anti-islanding protection should immediately disconnect the unit.

Assuming that a solid single-phase-to-ground (SLG) fault takes place at Bus 305 (see Figure 2-11), Figure 2-39 shows the three-phase instantaneous voltage of the BESS bus (i.e., Bus 314) prior to and during the fault. It can be seen that the voltage of the faulty phase (Phase A) is significantly affected due to the fault, which will cause the anti-islanding protection of BESS 2 to very quickly initiate a trip.[15] However, since CCR2-32R will detect a forward (downstream) fault, it will block operation of the BESS 2 anti-islanding protection for a pre-defined time period (500 ms in this project). In other words, the pickup signal of Recloser CCR2-32R is communicated to BESS 2 through GOOSE messaging to work as a blocking signal for downstream faults.

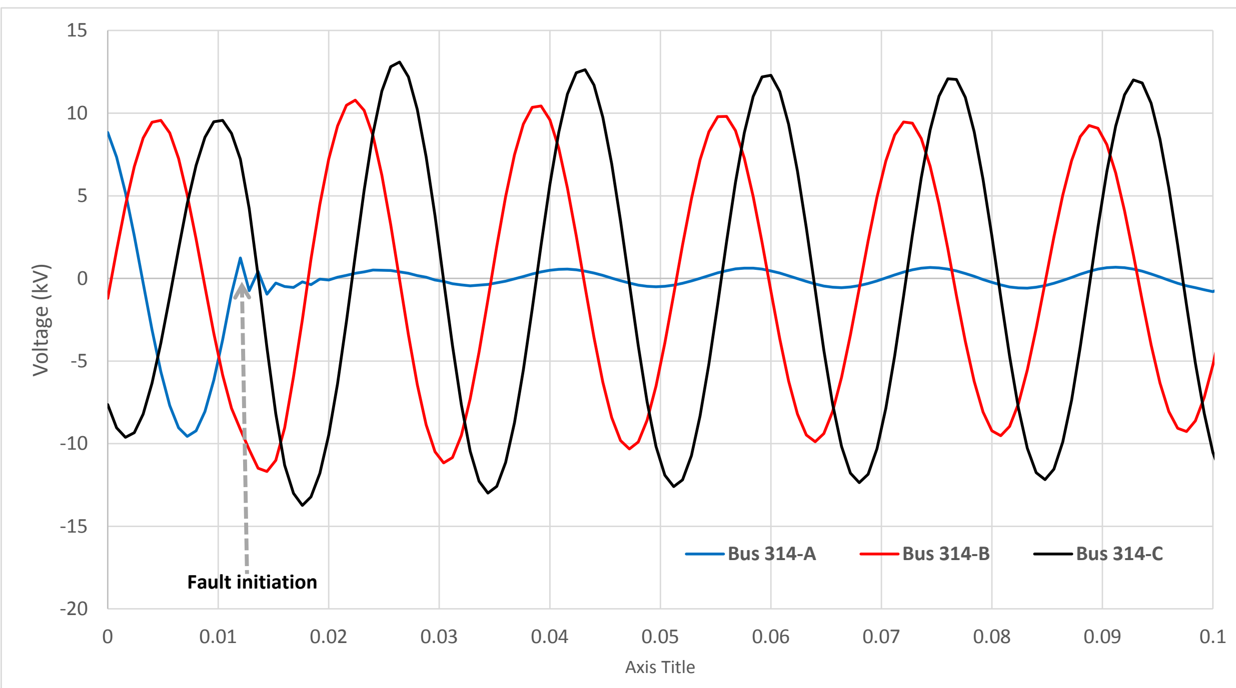

Figure 2-39. BESS voltage prior and during a fault at Bus 305.

[15] IEEE 1547 Standard has been used in this project for the design of the DER anti-islanding protection.

Figure 2-40 illustrates trip and blocking signals generated during the SLG fault on Bus 305. Figure 2-40 (a) shows that the local anti-islanding trip signal of BESS 2 (BESS trip initiation signal) has picked up in about 297 ms after the fault initiation. However, since CCR2-32R has already detected the forward fault and issued the pickup signal (see Figure 2-40 (b)), the BESS local trip is blocked. This is shown in Figure 2-40 (d) where the final BESS 2 trip signal has not picked up. Meanwhile (while the BESS 2 trip is blocked for 500ms), Recloser CCR2-32R has isolated the fault by tripping its corresponding breaker (see Figure 2-40 (c)).

Figure 2-41 shows the fault voltages and current prior to, during, and subsequent to the fault scenario described earlier. Figure 2-41 (a) and Figure 2-41 (b) indicate that, subsequent to the fault, the BESS voltage is retrieved, confirming proper operation of the anti-islanding scheme augmented with the blocking signal. The results of remaining test cases are provided in Appendix D – Additional Use Case results.

2.8.8.3.2 Case 7.11: Grid support through power factor and voltage control

For Case 7.11, illustrated previously in Table 2-25, the system is highly-loaded while the PV generation is relatively low. Further, one of the batteries (BESS 2) is in charge mode. Initially, the power factor target of this circuit is set at 0.9, which is lower than the prevailing power factors of the circuits (i.e., 0.94 for CCR1 and 0.965 for CCR2). Therefore, the implemented logic at the RTAC does not take any action. Then, the following targets are selected for the power factor at the substation level:

(1). $PF_{target1}$=0.95
(2). $PF_{target2}$=0.98

Figure 2-42 through Figure 2-45 indicate the system response to the aforementioned sequence of targets defined for the power factor (orange circles show the time at which a new power factor target is defined). As can be observed in these figures, the controller has utilized DERs to achieve the power factor target. This is shown in Figure 2-42, where the controller has modified the DER reactive power setpoints for improving circuit power factor. Figure 2-43 and Figure 2-44 show the real and reactive power of Circuit 1 (CCR 1) and Circuit 2 (CCR 2), respectively.

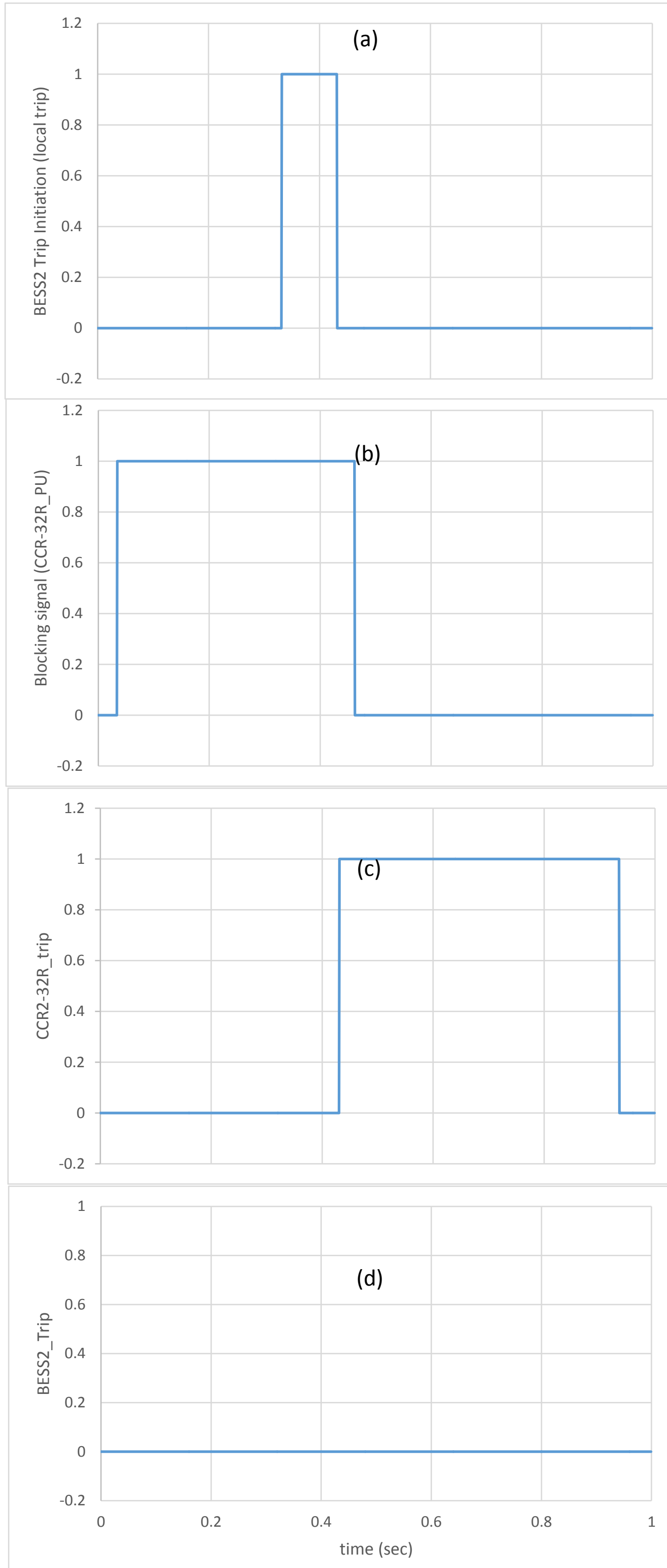

Figure 2-40. Trip signals for an SLG fault downstream of the CCR2-32R (Case 7.5)

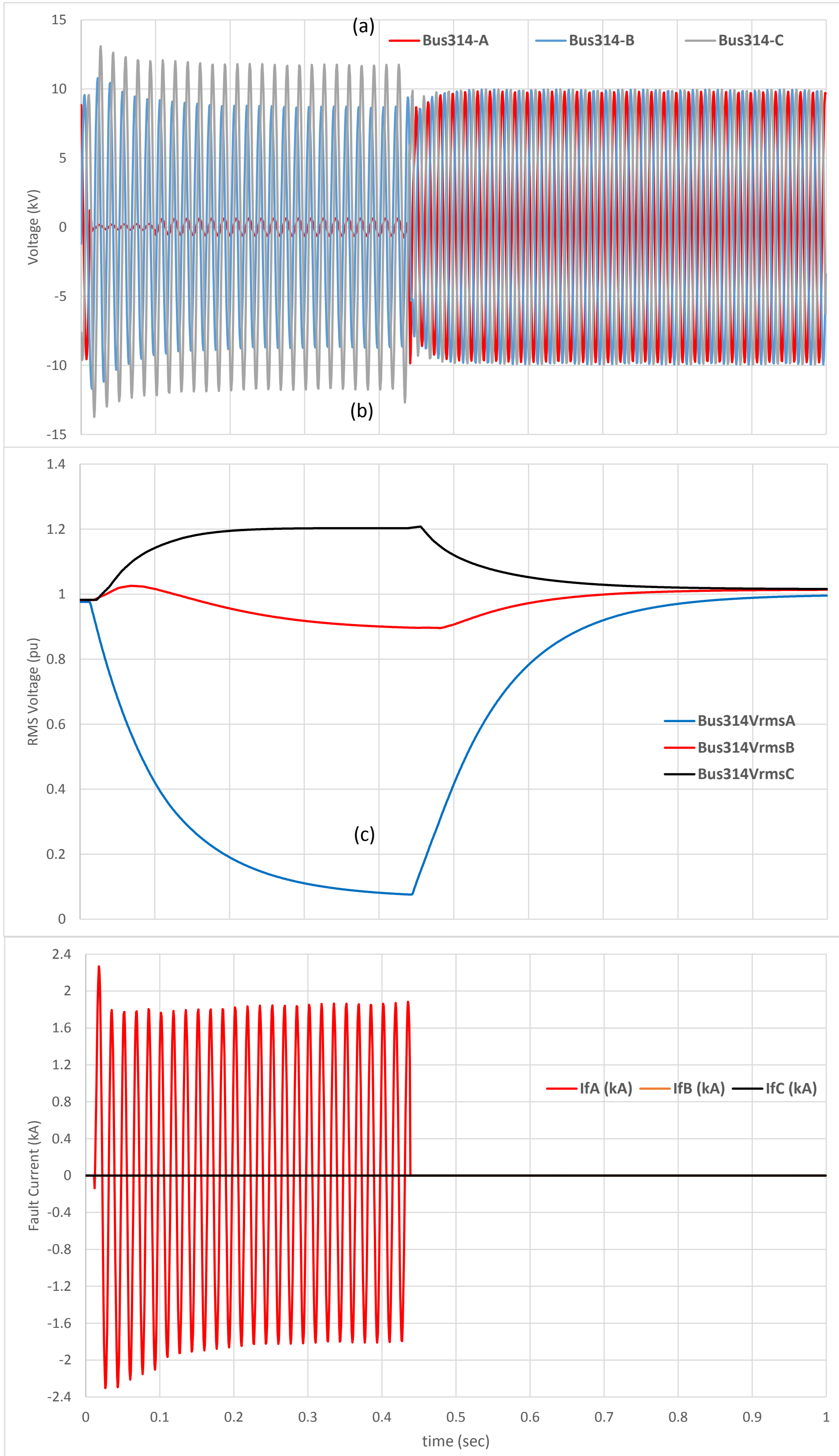

Figure 2-41. Fault voltages and current prior, during, and subsequent to an SLG fault on Bus 305.

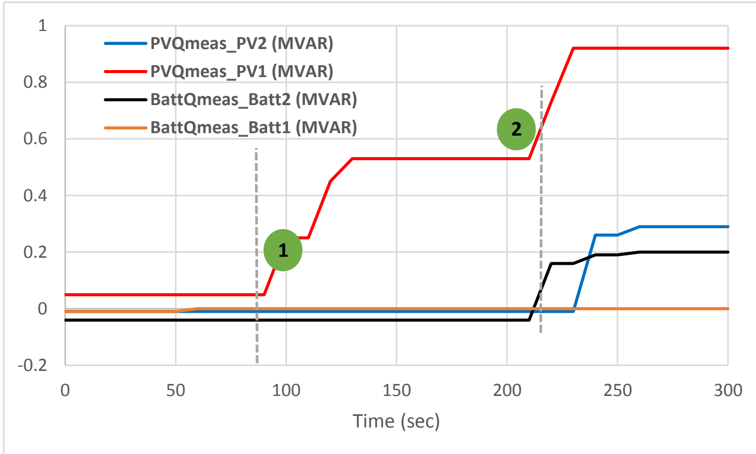

Figure 2-42. Reactive power contribution of DERs during the test (Case 7.11)

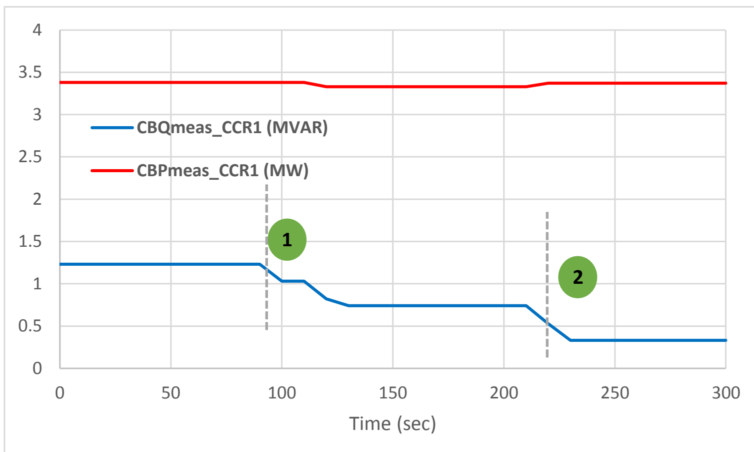

Figure 2-43. Real and reactive power flowing through the feeder breaker (CCR1) (Case 7.11)

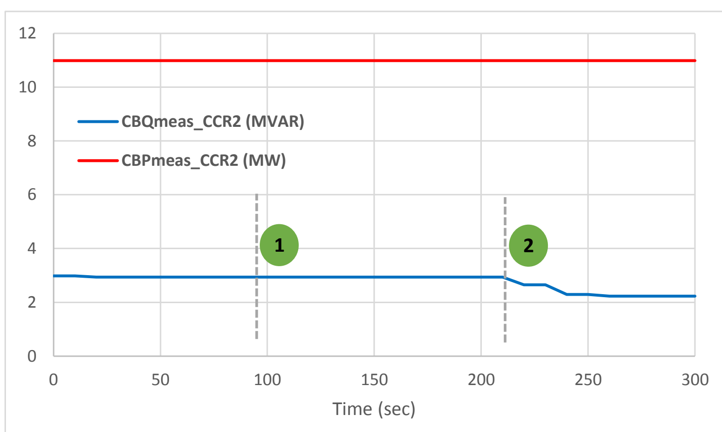

Figure 2-44. Real and reactive power flowing through the feeder breaker (CCR2) (Case 7.11)

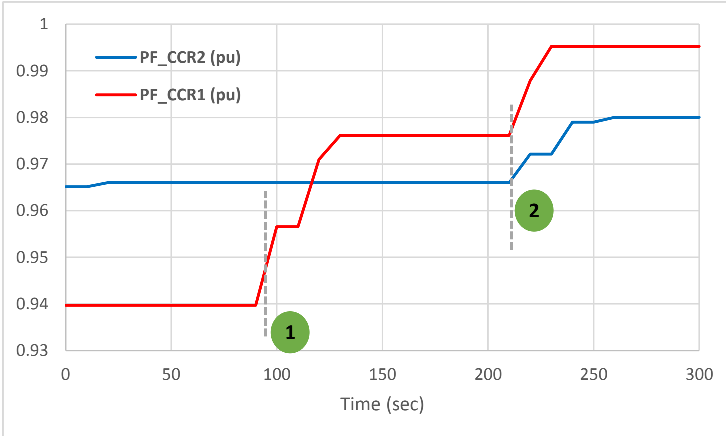

Figure 2-45. Circuit power factors during the test (Case 7.11)

As shown in Figure 2-40 and Figure 2-44, with increased reactive power contribution of DERs, the total reactive power drawn from the grid decreases. This, in turn, results in the improved power factor at both circuit and substation levels. Figure 2-45 shows the calculated power factor for both CCR 1 and CCR 2. It is evident from the figure that, with the DER contributions, both power factor targets (0.95 and 0.98) are achieved.

It should also be noted that, in this use case, the voltage of major points are continuously reported to the feeder controller through GOOSE messages. The controller will try to adjust the voltage through utilization of the most appropriate DER (for example, the closest DER to the monitored point). This use case attempts to keep the voltage of various points in the circuit within a range that is adjustable by the operator. In this test case, this range has been defined to be between 0.98 pu and 1.02 pu. Figure 2-46 shows the voltage of a monitored bus (Bus 305) during the test. It can be observed that the voltage has been regulated and brought to the target range.

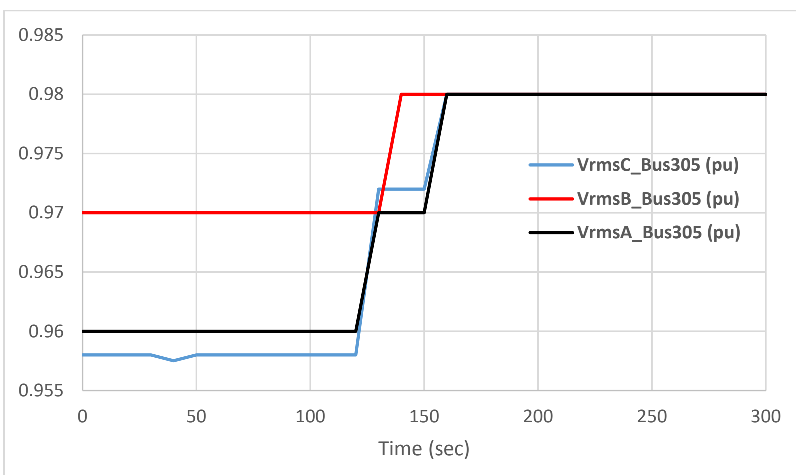

Figure 2-46. Voltage of Bus 305 during the test (adjusted by reactive power contribution of BESS 2)

2.8.8.4 Findings

The following is a list of findings for this use case:

- This use case shows how peer-to-peer communications among DERs and other protection and control equipment can enhance distribution system operation through
  - Improved power factor at the substation level obtained by increased involvement of DERs
  - Enhanced voltage profile through proper DER reactive power contribution
- The direct communication between DERs and the downstream protective device(s) can provide coordination between system protection and low-voltage ride-through (LVRT) capability of DERs. In particular, the following observations were made through the course of test execution:
  - For a downstream fault, the downstream protective device will block the operation of the anti-islanding protection of DERs for a specified period of time, which is not longer than the utility/standard requirement. This will afford time to the protective device to clear the fault and prevent unnecessary operation of the DER. This is important, as the trip of the DER for such a fault case can aggravate the situation.
  - For an upstream fault, direct transfer trips (DTT) will be sent to the DER within the islanded feeder to ensure anti-islanding protection.
- The peer-to-peer communication between DER and other protective equipment can improve both security and dependability of DER anti-islanding protection.

2.8.9 Use Case 8: Emergency load management tests

2.8.9.1 Problem statement

Currently, SDG&E performs surgical load shedding based on pre-determined look-up tables with rotational schedules for the distribution circuits that can be placed in outage order. When an emergency load shedding request is made by the California Independent System Operator (CAISO), the pre-scheduled look-up table will define which circuits shall be shed. The schedule incorporates information on type of customers connected to the circuits and excludes outage on circuits that serve critical facilities such as hospitals, elderly residential housing, fire stations, etc. However, since the current practice works based on the circuit interruption, there is a possibility that more loads than required are de-energized in response to a load-shedding request.

With the increasing integration of DER, there will be opportunities to minimize customer interruption during emergency conditions. This can be done through effective utilization of DER contributions to offset customer loads. In other words, proper dispatch of DERs can potentially help with efficient load management in distribution circuits. If there are cases where loads must be disconnected, it can be determined based on real-time measurements and controls such that the smallest possible amount of load is de-energized to achieve the defined load-management target. Further, an improved rotational scheme can be employed to improve the load shedding strategy.

2.8.9.2 Description and objectives

The main objectives of this use case is to monitor field data and properly utilize DERs in order to:

- Reduce the need for disconnecting large numbers of customers, based on the generation contribution from DERs, and
- Use the real-time information from field assets to perform partial load shedding, to restore some loads through alternative power sources if possible, and to rotate the scheduled outages more frequently as the need for load reduction changes.

Field monitoring and fast control will help to reduce the amount of reserve load reduction (margin for load fluctuation sensitivity), since a fast partial load shedding scheme can be implemented through IEC 61850 GOOSE and active communication of DER and load fluctuations. GOOSE messaging was used for controls in this use case. Figure 2-47 presents the logic diagram of the emergency load management (ELM) use case.

2.8.9.3 Test cases and results

This use case aims at utilizing DERs for emergency load management in distribution networks. The goal of the use case is to improve system reliability and economics by reducing load interruption during emergency situations. In other words, the emergency load shedding request by an ISO can be addressed with no load interruption or partial load shedding if DERs can be involved (properly dispatched) during the process. The logic diagram of this use case is provided in Figure 2-47.

The performance of the ELM function is evaluated through a full set of tests as described in Table 2-26. Similar to previous use cases, only the results of a selected number of cases is presented and briefly discussed in the following subsections, due to space limitations. Results of other cases are provided in Appendix D – Additional Use Case results.

2.8.9.3.1 Case 8.1: Real-time power flow control of substation banks

In this use case, it was demonstrated how the active power flow through substation transformer banks can be controlled by effective utilization of DERs. The RTAC at the substation continuously monitors the real power flow through the transformer banks. If this power exceeds a threshold defined by the operator, the additional required power is calculated. The RTAC will then communicate the calculated power target of each control zone to the corresponding controller of the zone. Subsequently, the control zone host/engine will determine the DER power setpoints to achieve the target. If the target is achieved by only dispatching DERs, a “successful” alarm is issued to the SCADA; otherwise, the operator will receive a “fail” alarm.

In Case 8.1, the power target of the transformer bank is set at P_{maxH}=8 MW.[16] The power flowing through both substation transformer banks are shown in Figure 2-48. As can be seen in this figure, the power of the North transformer bank is higher than the threshold (8 MW) prior to the activation of the use case

[16] It is acknowledged that this is a very low threshold, but it is selected for the evaluation of the use case.

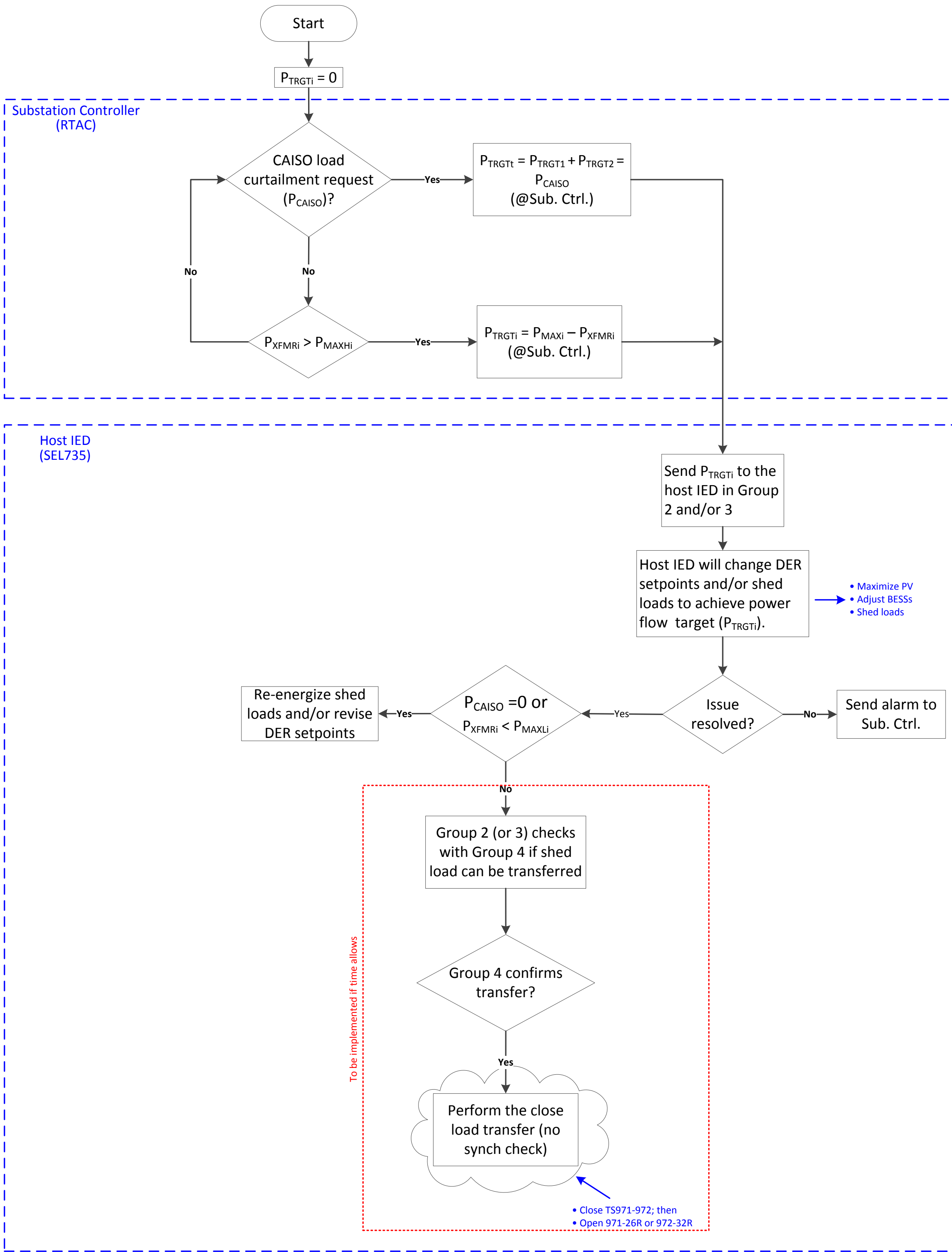

Figure 2-47. Logic diagram of the ELM use case

Table 2-26. ELM test cases

Case#	Test Conditions	Description	Remark
8.1	CCR1: Pload= 1pu, PPV1=0.7 MW (SR=0.2pu) CCR2: Pload=1pu, PPV2=0.5 MW (SR=1pu), PBESS1=0, PBESS2=0 PCAISO=0 MW	High load profile (fix), low PV (fix)	Pxfmr to be adjusted by the control scheme
8.2	CCR1: Pload= 1pu, PPV1=0.7 MW (SR=0.2pu) CCR2: Pload=1pu, PPV2=0.5 MW (SR=0.5pu), PBESS1=0, PBESS2=0 PCAISO=3 MW	High load profile (fix), low PV (fix)	Achieve power target, as applicable
8.3	Continue Case 8.2 with PCAISO=1.5 MW	High load profile (fix), low PV (fix)	Achieve power target, as applicable
8.4	Continue Case 8.3 with PCAISO=2 MW	High load profile (fix), low PV (fix)	Achieve power target, as applicable
8.5	CCR1: Pload= 1pu, PPV1=1 MW (SR=0.4pu) CCR2: Pload=1pu, PPV2=0.7 MW (SR=0.5pu), PBESS1=0.5, PBESS2=1, PCAISO=0 MW	High load profile (fix), medium PV (fix)	Pxfmr to be adjusted by the control scheme
8.6	Repeat Case 1.3 with PV2 out of service		
8.7	CCR1: Pload= 1pu, PPV1=0.7 MW (SR=0.2pu) CCR2: Pload=1pu, PPV2=0.5 MW (SR=0.5pu), PBESS1=0, PBESS2=0 PCAISO=3 MW (BESS2_SOC<20%)		
8.8	Continue Case 8.4 with PCAISO=0 MW	High load profile (fix), low PV (fix)	Achieve power target, as applicable
8.9	Continue 8.5 with PCAISO=2 MW		
8.10	Continue 8.9 with PCAISO=1 MW		
8.11	Continue 8.10 with PCAISO=1 MW		

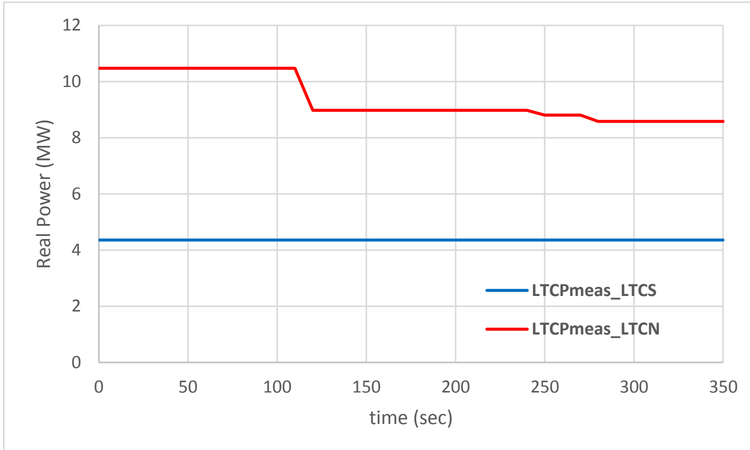

Figure 2-48. Power of the transformer banks during the test (Case 8.1)

logic at about t=100s (red line). Once the logic is enabled, the power targets are calculated for each control zone. The controller of each zone will then dispatch DERs to limit the power of the transformer banks.

Figure 2-49 presents the output power of the DERs during the aforementioned tests. The figure shows that the algorithm first uses all of the PV 2 capacity (by releasing the curtailed power) and then calculates the BESS setpoints for achieving the target. It is also important to note that since the power of the South transformer bank is below the threshold (P_{maxH}>4.3 MW), no adjustment has been done on DERs connected to Circuit CCR1 (see Orange line in Figure 2-49). Finally, it can be seen that the power of the North transformer bank becomes less than the threshold subsequent to the successful completion of the test (see red line in Figure 2-48).

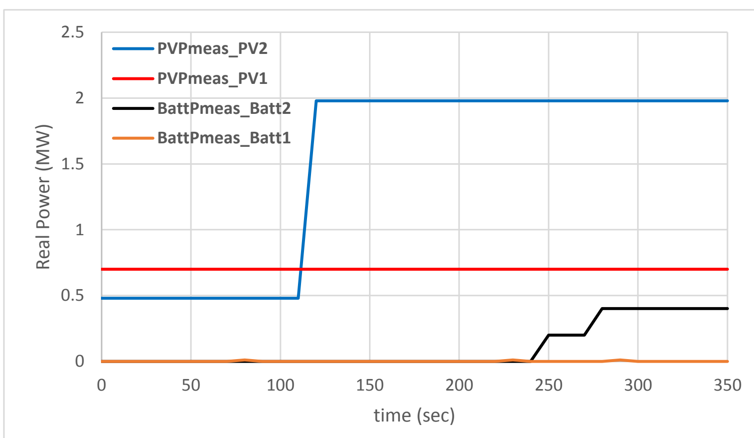

Figure 2-49. Power of the DER units during the test (Case 8.1)

2.8.9.3.2 Case 8.9: California ISO load shedding request.

In previous test cases, there was no load-shedding request from CAISO (P_{CAISO}=0 MW). Once CAISO makes a request, it will be addressed with a higher priority. Assuming a case where PV2 is out of service (e.g., due to a fault), and CAISO sends a 2- MW request (other DERs have some initial power values), the request is received by the substation RTAC, and it will determine the power target of each control zone based on the reserve capacity calculation.

The control zone engine will first maximize the power drawn from the renewable resources (e.g., PVs) and then defines BESS setpoints. As shown in Figure 2-50, the majority of the power comes from the curtailed section of PV 1, and the rest is supplied by both BESSs. As a result, the total amount of 2 MW is achieved through the contribution of DERs. This is shown on Figure 2-51, where the total amount of decrease in transformer bank powers is about 2 MW.

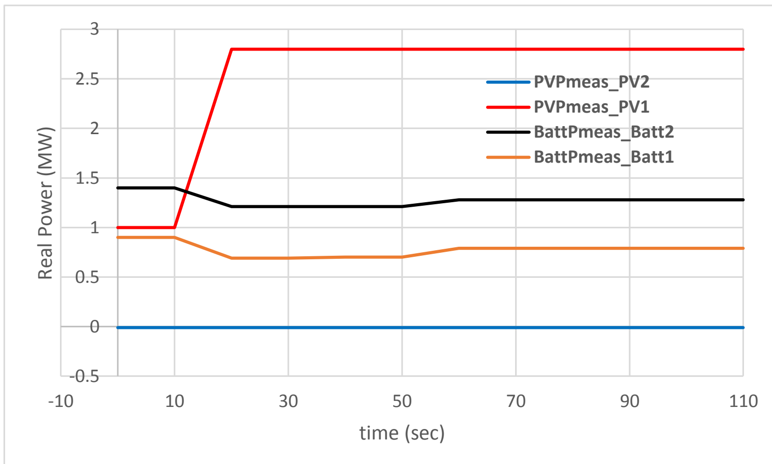

Figure 2-50. Power of the DER units during the test (Case 8.9)

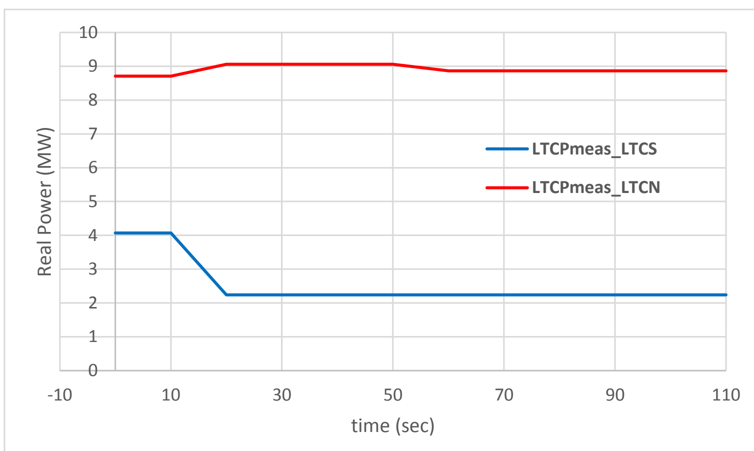

Figure 2-51. Power of the transformer banks during the test (Case 8.9)

2.8.9.3.3 Case 8.10: California ISO load shedding request.

Assuming that another 1- MW power request is made by the CAISO (continuation of Case 8.9), and considering that the maximum power is already drawn from the PV system (PV 1) based on the prevailing solar radiation, the only resources left to supply the remaining powers are BESS 1 and BESS 2 (note that PV 2 is out of service). Figure 2-52 and Figure 2-53 show the DER output power and the transformer bank power during this test. These figures indicate that the 1- MW request is addressed by the dispatch of BESSs (note the change in the power of North transformer bank in Figure 2-53).

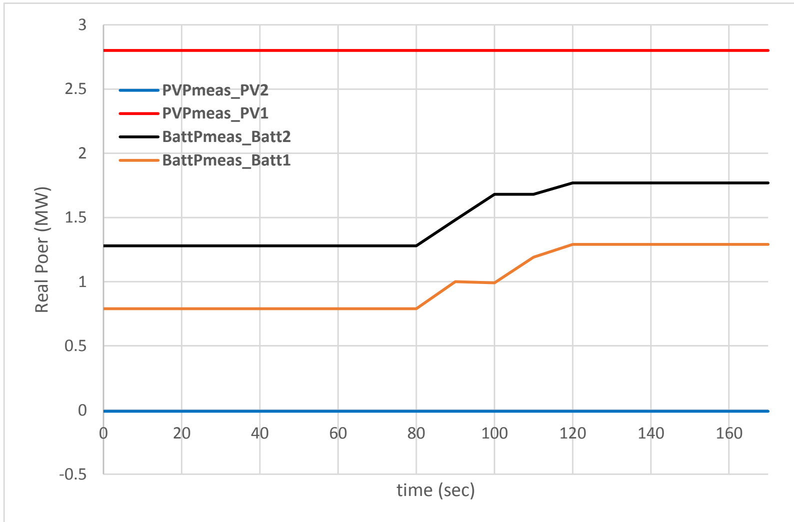

Figure 2-52. Power of the DER units during the test (Case 8.10)

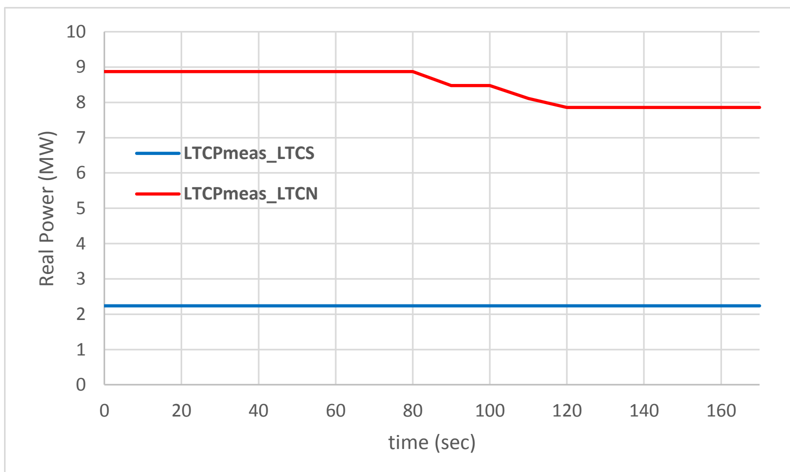

Figure 2-53. Power of the transformer banks during the test (Case 8.10)

2.8.9.3.4 Case 8.11: California ISO load shedding request.

Assuming that another 1- MW request is made by the CAISO for a third time (continuation of Case 8.10), Figure 2-54 and Figure 2-55 show the DER output power and the transformer bank power during this test. It can be observed that the output power of BESS 2 has not changed during the test, although it still has some capacity left. This is because the State of Charge (SOC) of this battery is critical (less than 20%) and, thus, the control zone host does not load the battery further. However, since the request cannot be fully addressed by BESS 1 (even at full capacity), the algorithm shed the sheddable load (CCR2-30R) as shown in Figure 2-56.

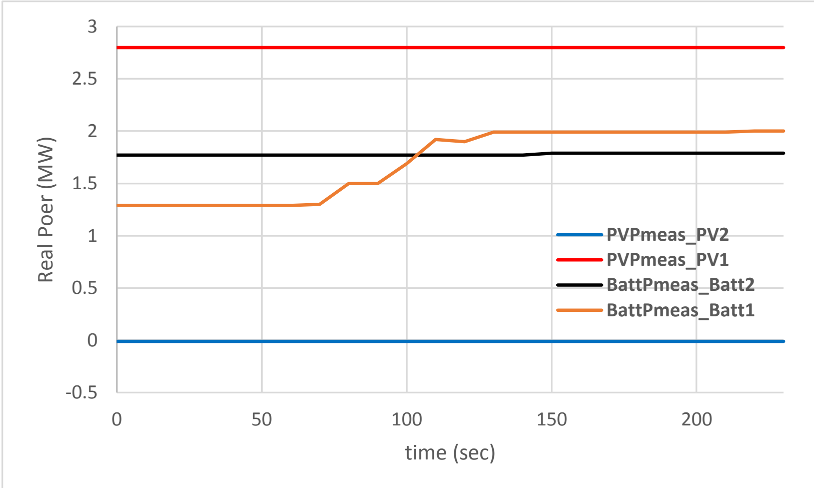

Figure 2-54. Power of the DER units during the test (Case 8.11)

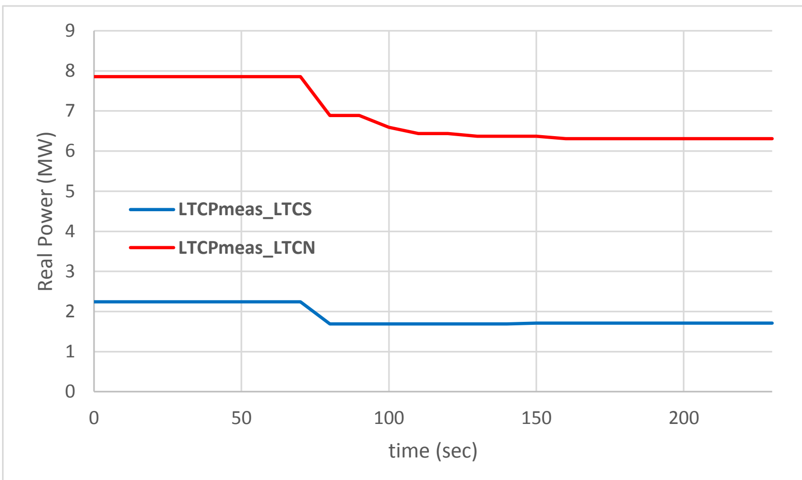

Figure 2-55. Power of the transformer banks during the test (Case 8.11)

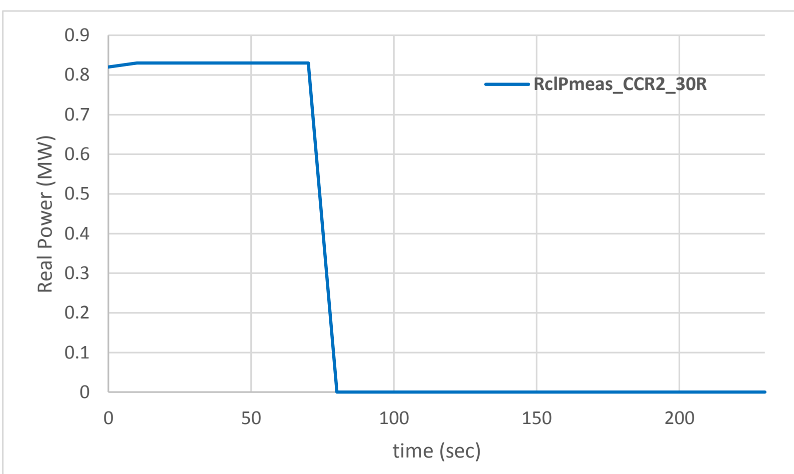

Figure 2-56. Load shedding performed by the use case logic to address the load shedding request (Case 8.11)

The results of the remaining test cases are provided in Appendix D – Additional Use Case results.

2.8.9.4 Findings

The following is a list of findings for the ELM use case:

- Integrating DERs into the distribution system control can improve performance of the system under emergency condition. This use case shows how DERs can be effectively employed to:
  - Address ISO load shedding requests with minimum interruption (or in some cases, no interruption) to customers. This will enhance reliability parameters normally used in system reliability analysis.
  - Control the power flow through the transformer banks at the substation on a real-time basis.
  - To manage reverse power flow through effective use of BESS while maximum energy is obtained from renewable resources.
- The peer-to-peer communications with DERs enables implementing a distributed control for distribution systems. Such an approach can enhance the reliability of the control system (advanced fail-safe).
- Since this use case utilizes a distributed control approach in which some control decisions are made within distributed control zones, it is very important that the control zone hosts at least one IED with a certain amount of control logic capability. It was found that most of the typical equipment used for feeder protection do not have enough control logic capability to enable a distributed control approach.
- During the course of the pre-commercial demonstration phase, it was discovered that some of the feeder IEDs did not have the capability to subscribe to analog GOOSE messages. This ability is a pre-requisite for functioning as a control zone engine – so this needs to be taken into account when selecting IEDs for this role.

2.8.10 Use Case 9: Dynamic emergency load control and management with DERs using OpenFMB

2.8.10.1 Problem statement

While high penetration of DERs, particularly variable energy resources (VERs) such as PV systems, are changing the shape of the distribution systems, they offer solutions for local load management of distribution circuits. In many cases, with the control of active and reactive power contribution of large DERs, the power flow limits of feeders (forward or reverse direction) can be controlled, under high- or light-load conditions. It is noted that DERs on circuits need to be closely controlled to enable direct interaction with the grid operator.

Dynamic Emergency Load Control and Management (DELCAM) can improve system performance in a distribution grid dominated by DERs. Two major challenges to achieve this objective are: 1) control and operation of large number of DERs that are distributed along the circuits, and 2) remote communications with DERs in the field environment. For the purpose of this use case, the communication is established in the Open Field Message Bus (OpenFMB) framework.

2.8.10.2 Description and objectives

This use case incorporates development of an OpenFMB communication platform for monitoring and control of DERs and field devices on distribution circuits. The objective is to investigate capabilities of OpenFMB framework for managing the communications among various field devices (primarily, DERs and feeder breaker). The new architecture should be able to enable peer-to-peer communications in a coordinated and standard fashion. Field devices with various communication protocols are included in the use case to demonstrate functionalities of OpenFMB in data exchange and traffic control.

OpenFMB will be an extension of substation communication bus to directly interact with field devices. The communication capabilities of a DER are used in this case to change the DER setpoints in order to maintain a loading level (power flow level condition) for the circuit specified by the system operator. The proposed test setup for this use case incorporates OpenFMB based field monitoring, communications, and data management with multiple devices, including:

- Interface to Distribution System Operator (DSO) though a RAMCO[17] device;
- Peer-to-peer communications and monitoring of circuit loading through a CB relay;
- Peer-to-peer communications, monitoring, and control of a utility-scale energy storage system, installed on the circuit under investigation, downstream of the CB;

In addition, the use case incorporates the grid interconnection aspect of the battery energy storage system (BESS) during unintentional islanding. By monitoring the CB status, a direct transfer trip signal is sent to the BESS to cease energization of the circuit. As a feedback signal, the open status of the BESS breaker (or control mode change) will be communicated to the CB relay to enable reclosing as required.

A high-level system diagram including main components involved in this use case is illustrated in Figure 2-57. The dashed lines shows other communication paths that exist, but are not studied in this use case.

[17] Regional Aggregator, Monitor, and Circuit Optimizer.

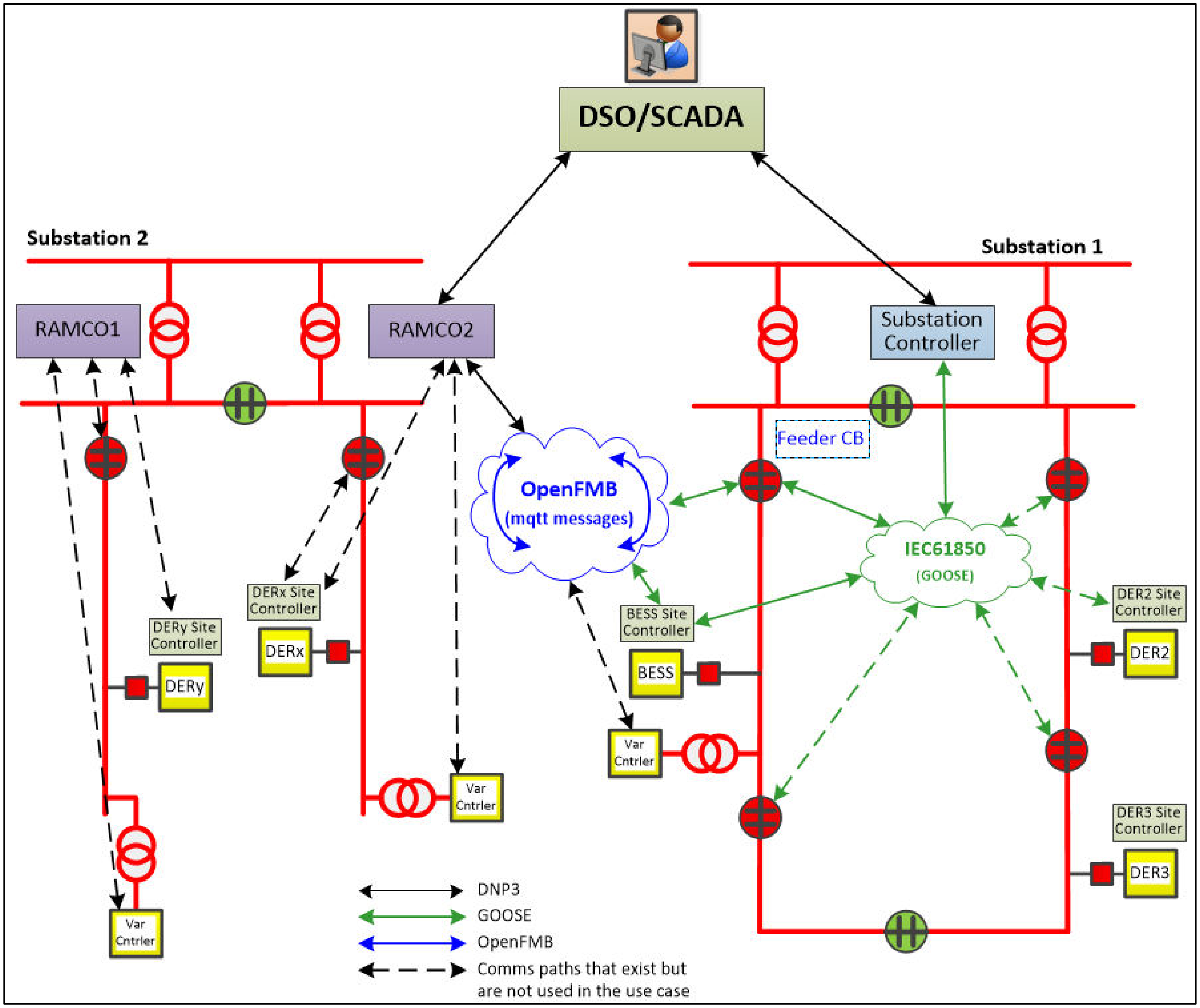

Figure 2-57. A high-level system diagram and data flow for the DELCAM use case

2.8.10.3 Test cases and results

Several test cases were considered to evaluate the performance of this use case and to ensure enhanced operation of the system using OpenFMB communication platform. Table 2-27 lists the tests executed for the evaluation of the DELCAM use case. Due to space limitations, only the results of two test cases will be presented and briefly discussed in the following subsections. The results of additional tests cases are provided in Appendix D.

Table 2-27. DELCAM test cases

Case #	Description	Remark
9.1	DSO/SCADA setpoints are zero, and no power adjustment is requested; Load variations and PV variations are applied; CB power flow follows the changes in the load and PV	Executed for Case 9.2, 9.3, and 9.5/9.6 (3 cases total)
9.2	DSO/SCADA sends initialization, along with setpoints for Interval 1 Interval 1 (early morning): load is the range of 4 to 6 MW and PV production forecast is in the range of 1 to 2 MW CB Setpoint 1: P < 4 MW and Q < 1 Mvar (BESS SOC > 50%)	Low PV profile (1-2 MW) and High Load profile (4-6 MW); trip CCR2-932CW.
9.3	DSO/SCADA sends initialization, along with setpoints for Interval 1 Interval 2 (noon time frame): load is the range of 2 to 3 MW and PV production is strong and expected in the range of 4 to 6 MW CB setpoint 2: P > -1.5 MW and pf is close to 1 (as much as possible)	High PV profile (4-6 MW) and Low Load profile (2-3 MW)
9.4	Due to a fault, CB is tripped; BESS needs to get also disconnected. (evaluate total response time, from CB open to BESS disconnect / change of mode)	Test was repeated five/5 times
9.5	DSO/SCADA sends initialization, along with setpoints for Interval 3 Interval 3 (evening time frame): load is the range of 4 to 6 MW and PV production forecast is low CB Setpoint 3: P < 5 MW and Q < 1 Mvar	No PV profile and High Load profile; P_setpoint is changed to 3 MW; then, Q_setpoint is changed to -2 MW;
9.6	DSO/SCADA sends initialization, along with setpoints for Interval 2 Interval 2 (noon time frame): load is the range of 2 to 3 MW and PV production is strong and expected in the range of 4 to 6 MW CB setpoint 2: P > -2 MW, and -1 MW < Q < 1 MW	High PV profile and Low Load profile; changed Q_setpoint to -2 MW;

In Case 9.3, a high PV profile and a low load profile have been used for the test (noon time frame). In addition, the real/active power setpoint defined by the DSO operator is set at P_{DSO} = –1.5 MW; this means that the RAMCO logic should keep the real power flow of the feeder greater than –1.5 MW. Figure 2-58 shows the real power flow through feeder CB when the BESS is not utilized (RAMCO logic is not activated). This figure indicates that, due to the high PV generation, a significant reverse power flows through this CB (note blue line in Figure 2-58). The goal of this test is to limit the reverse power flow through feeder CB to about –1.5 MW.

Figure 2-59 shows the real power flow of the CB when the RAMCO logic is enabled to adjust the BESS setpoints through OpenFMB platform. The figure also illustrates the plot of the BESS output power during the test. As can be observed in Figure 2-59, the real power of the CB has been regulated to meet the target defined by the DSO operator, i.e., –1.5 MW (note green line in Figure 2-59). This is done through the controlled charging of the BESS located downstream on the CB (see gray line in Figure 2-59).

It is also worth mentioning that, due to the RAMCO processing and calculation time, the target is normally met with a certain delay.

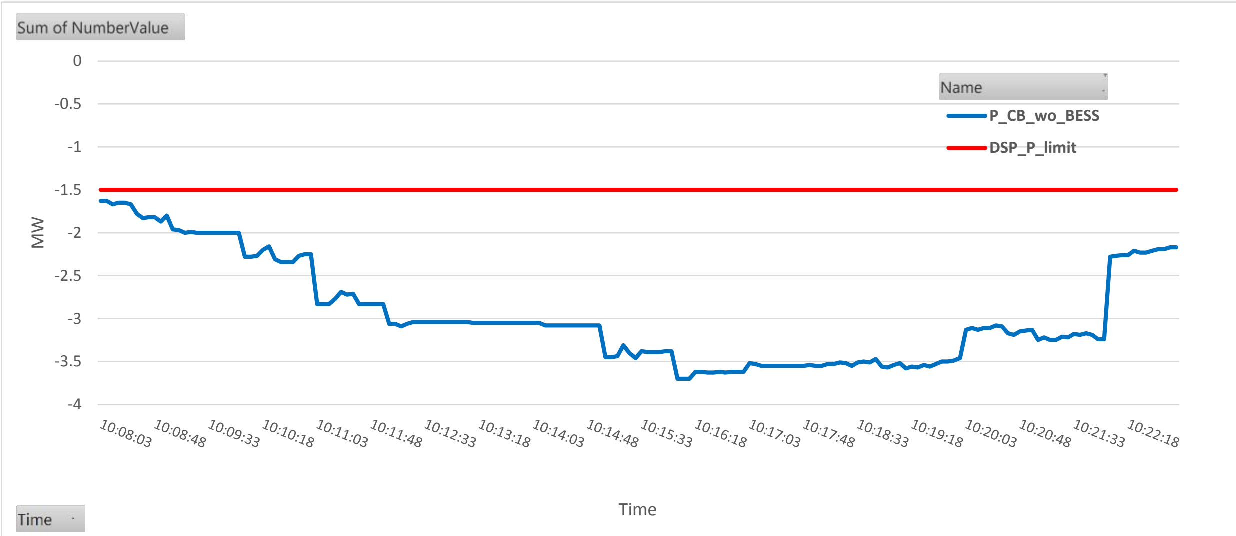

Figure 2-58. Real power flow through feeder CB without BESS contribution (Case 9.3)

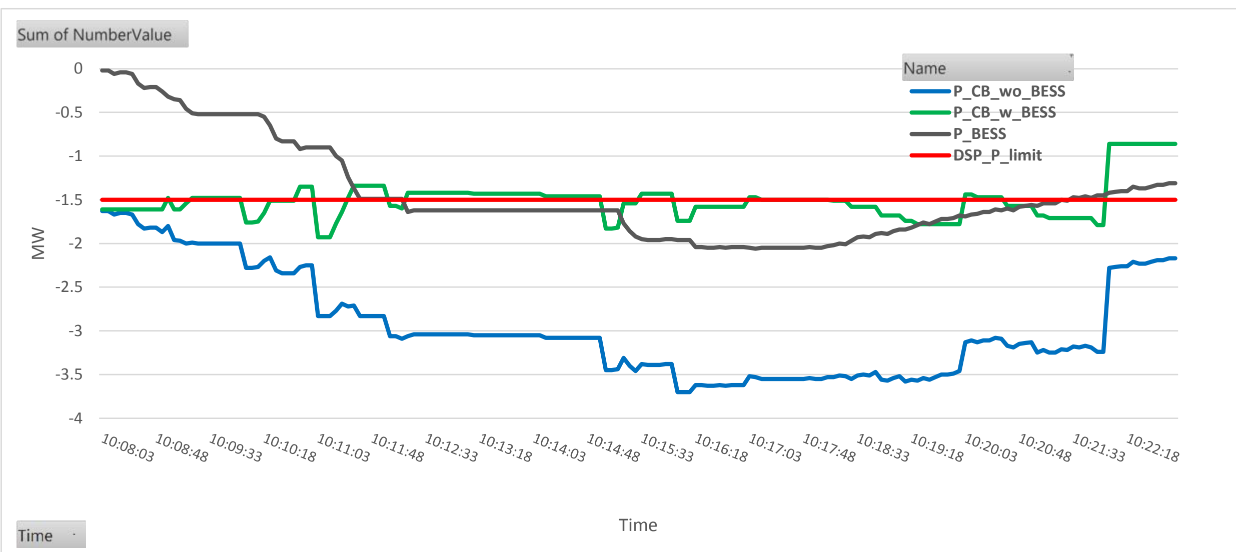

Figure 2-59. Real power flow through feeder CB with BESS contribution through OpenFMB platform (Case 9.3)

In Case 9.2 the situation is low PV profile and high load profile (early morning time frame). In this case, the reactive power target of the DSO (Q_{DSO}) is 1 Mvar , that is, the RAMCO should maintain the reactive power of the circuit below 1 Mvar . Figure 2-60 shows the reactive power flow of the CB when the RAMCO logic is enabled and adjusts the BESS contribution through OpenFMB platform. As can be observed in this figure, the reactive power of the CB is always below the target (1 Mvar), through the

BESS support located downstream on the CB. It should be noted that a Cap Bank is tripped at 10:52 to examine the system performance under transient situations.

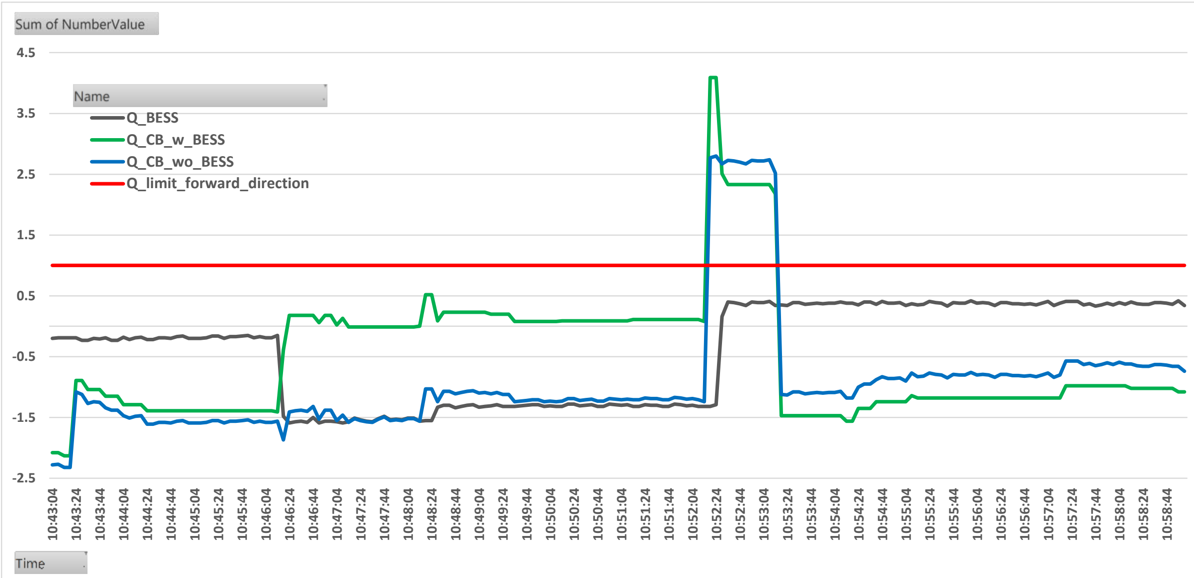

Figure 2-60. Reactive power flow through feeder CB with and without BESS contribution (Case 9.2)

The second category of tests considered in this use case are related to the communication-assisted anti-islanding protection of DERs. The purpose of this category of tests is to determine how long it will take to disconnect a DER from the circuit subsequent to an islanding situation, using OpenFMB communication platform. To that end, the time between the instant that the CB opens until de-energization of the BESS is calculated for several test scenarios. These results are tabulated in the following table for 5 tests:

Table 2-28. Anti-islanding test cases with OpenFMB

Run	Time	Event	Round Trip (s)
	00:36:24.995	BESS confirmation received	
1	00:36:22.545	BESS command sent	2.45
	00:36:22.545	CB Opens	
	00:44:03.895	BESS confirmation received	
2	00:44:01.846	BESS command sent	2.049
	00:44:01.846	CB Opens	
	00:49:07.546	BESS confirmation received	
3	00:49:05.846	BESS command sent	1.7
	00:49:05.846	CB Opens	
	00:52:19.995	BESS confirmation received	
4	00:52:18.845	BESS command sent	1.15
	00:52:18.845	CB Opens	
	00:54:27.995	BESS confirmation received	
5	00:54:26.545	BESS command sent	1.45
	00:54:26.545	CB Opens	
Mean			**1.76**

Table 2-28 shows that the overall time for the anti-islanding protection of DERs are relatively large. In some cases, the time is even more that IEEE standard requirements[18]. This is mainly due to multiple (bi-directions) communication adaptors[19] being employed in the OpenFMB platform. One potential solution is to reduce pooling periods of the adapters (increase pooling frequency); however, the challenge for a large-scale implementation of the platform should be investigated. As will be discussed in next section (Section 2.8.11.3), similar tests will result in quite faster action when IEC 61850/GOOSE is being used for the communication between the CB relay and DER site controller.

2.8.10.4 Findings

The following is a list of findings for the DELCAM use case:

- OpenFMB framework can enable effective utilization of DERs to control the power flow through the feeder breaker on a real-time basis, considering load and (renewable) generation variations.
- The use of OpenFMB framework enables an integrated control system where field and substation devices with various communication protocols can be included in the control scheme (leading to a more optimized control).
- Open FMB enables interoperability with field devices and systems operating in the grid. The framework is compatible with multiple data models, communication protocols, and technologies. However, it should be noted that these are the application requirements that determine the success parameters and also limit the scope in an OpenFMB platform.
- Based on the results of anti-islanding tests, it can be cautiously concluded that OpenFMB communication platform is not suitable for very time-critical applications (such as system protection). This is mainly due to multiple (bi-directions) communication adaptors[20] being employed in the OpenFMB platform. Although the timing can be improved through the use of fast adapters, the challenge for a large-scale implementation of the platform is still valid and should be looked into.

2.8.11 Use Case 10: Dynamic circuit load management

2.8.11.1 Problem statement

As discussed earlier, DERs on circuits can be closely controlled to regulate loading level (power flow level condition) for the circuit specified by the system operator. Dynamic Circuit Load Management (DCLM) use case aims to achieve the same objective as Use Case 9 (see Section 2.8.10), except with the use of IEC 61850 communication protocol. Further, this use case investigates the advantages and disadvantages of using MMS (manufacturing message specification) for communications between the substation gateway and SCADA, as compared to DNP3 (distributed network protocol).

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[18] The excising IEEE 1547 standard requires a maximum of 2second operation for DER anti-islanding protection.

[19] In this study, DNP3 has been used as the bridging protocol to main devices utilized in the use case.

2.8.11.2 Description and objectives

This use case mainly focuses on development of an IEC 61850/MMS communication platform between SCADA and substation gateway/controller for monitoring and control of DERs and field devices on distribution circuits. In particular, the communications with field assets including DERs is done through IEC 61850/GOOSE protocol, but the DNP3 communication between the SCADA and substation was replaced with MMS to conduct a comparative analysis.

The proposed test setup for this use case incorporates IEC 61850-based field monitoring, communications, and data management with multiple devices in the test system (see Section 2.8.10.2). The use case also addresses the grid interconnection aspect of the BESS during unintentional islanding. By monitoring the CB status, a signal has to be sent to the BESS to cease energization to the grid when the CB opens. As a feedback signal, open status of the BESS breaker (or control mode change) should be communicated back to the CB relay to enable reclosing as required.

A high-level system diagram including main components involved in the OpenFMB DELCAM use case is illustrated in Figure 2-61. The dashed lines shows other communication paths that exist, but are not studied in this use case.

2.8.11.3 Test cases and results

Several test cases were considered to evaluate the performance of DCLM use case and to ensure enhanced operation of the system using IEC 61850 communication platform.

Table 2-29 lists the tests executed for the evaluation of the DCLM use case.

As shown in last row of Table 2-29, a number of tests were also executed to compare the response time of the MMS communication protocol with the conventional DNP3 protocol (utilized between substation gateway and SCADA center). Similarly, for the sake of brevity, only the results of limited number of cases are presented and discussed in this report. The results of additional tests cases are provided in Appendix D.

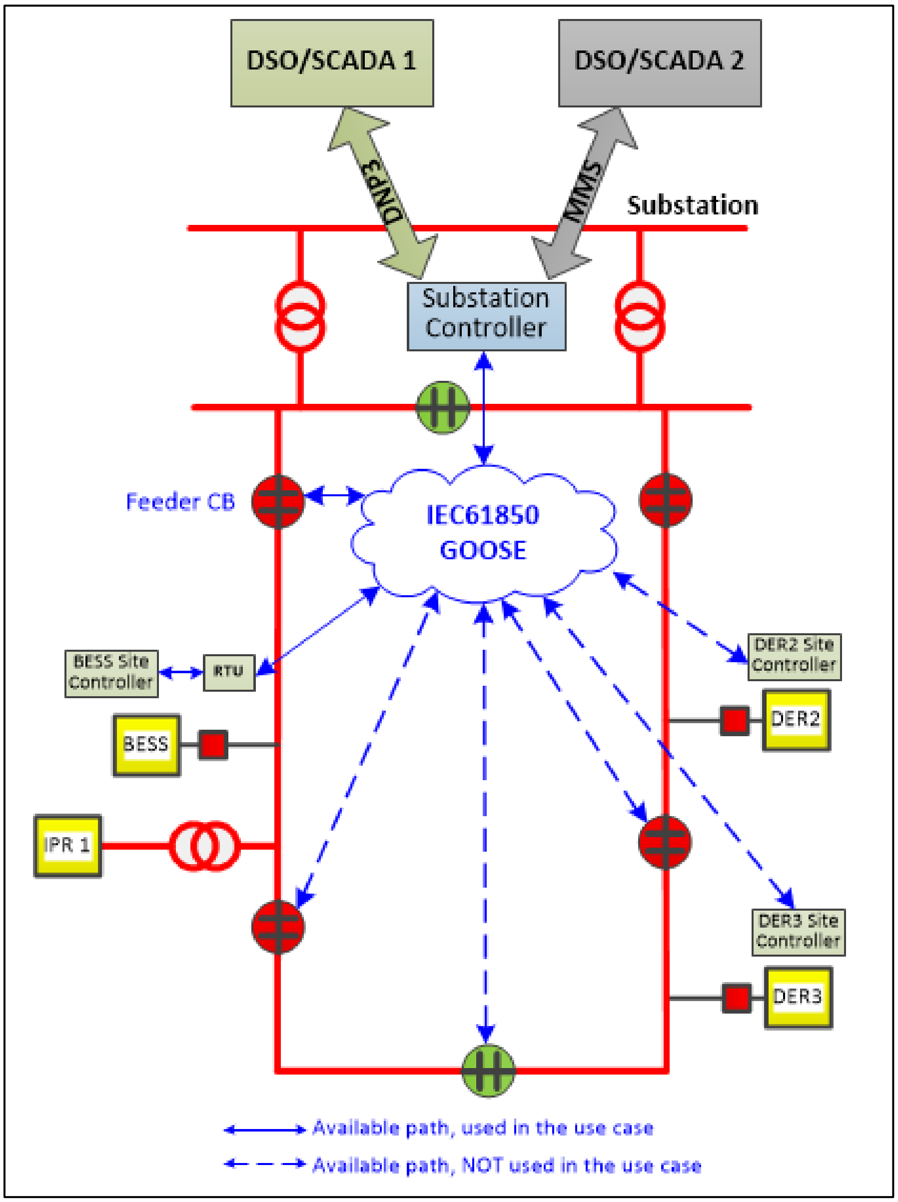

Figure 2-61. A high-level system diagram and data flow for DCLM use case

Table 2-29. DCLM test cases

Case #	Description	Remark
10.1	DSO/SCADA setpoints are zero, and no power adjustment is requested; Load variations and PV variations are applied; CB power flow follows the changes in the load and PV.	
10.2	DSO sends initialization, along with setpoints for Interval 1; Interval 1 (early morning): load is the range of 4 to 6 MW, and PV production forecast is the range of 1 to 2 MW; CB Setpoint 1: $P < 4$ MW, and $0 < Q < 1$ Mvar BESS SOC > 50% (BESS size is 2 MW)	Low PV profile (1-2 MW) and High Load profile (4-6 MW)
10.3	Interval 2 (noon time frame): load is the range of 2 to 3 MW, and PV production is strong and expected in the range of 4 to 6 MW CB setpoint 2: $P > -1.5$ MW, and pf close to 1 (as much as possible)	High PV profile (4-6 MW) and Low Load profile (2-3 MW)
10.4	Due to a fault, CB is tripped; BESS needs to be also disconnected. (evaluate total response time, from CB open to BESS disconnect or change of mode)	Test was repeated five/5 times
10.5	CB is reclosed (circuit is restored) DSO sends initialization, and performs control based on the prevailing system conditions (upon the control mode change to DCLM)	
10.6	Interval 3 (evening time frame): load is the range of 4 to 6 MW, and PV production forecast is very low CB Setpoint 3: $P < 5$ MW, $Q < 1$ Mvar	No PV profile and High Load profile.
10.7	Comparison of response times of MMS and DNP3 communication protocols for monitoring and control through SCADA	Several tests

Case 10.2 presents the case of a low PV profile and a high load profile (morning time frame). The real and reactive power setpoints, which are defined by the DSO operator, are set at P_{DSO} = 4 MW and 0 Mvar < Q_{DSO} <1 Mvar , respectively. Thus, the RAMCO logic aims at keeping the real power flow of the feeder smaller than 4 MW while maintaining the reactive power close to zero.

Figure 2-62 shows the real power flow through feeder CB with and without the BESS contribution (with and without RAMCO logic enabled). The BESS contribution (P) as well as the real power limit (P_Upper_Limit) are also shown in this figure. As can be clearly seen in Figure 2-62, the BESS contribution has always made the feeder real power to be smaller than 4 MW, which is the DSO target.

Figure 2-63 shows the reactive power flow through feeder CB with and without the BESS contribution (with and without RAMCO logic enabled). The BESS contribution (Q) as well as the reactive power limit (Q_Upper_Limit) are also shown in this figure. It is evident from Figure 2-63 that the BESS has absorbed reactive power (at its maximum capacity) to bring the feeder reactive power within the limit defined by the DSO operator. In time frames when the RAMCO cannot meet the target, it will send the additional required power (Delta_Q) to the DSO.

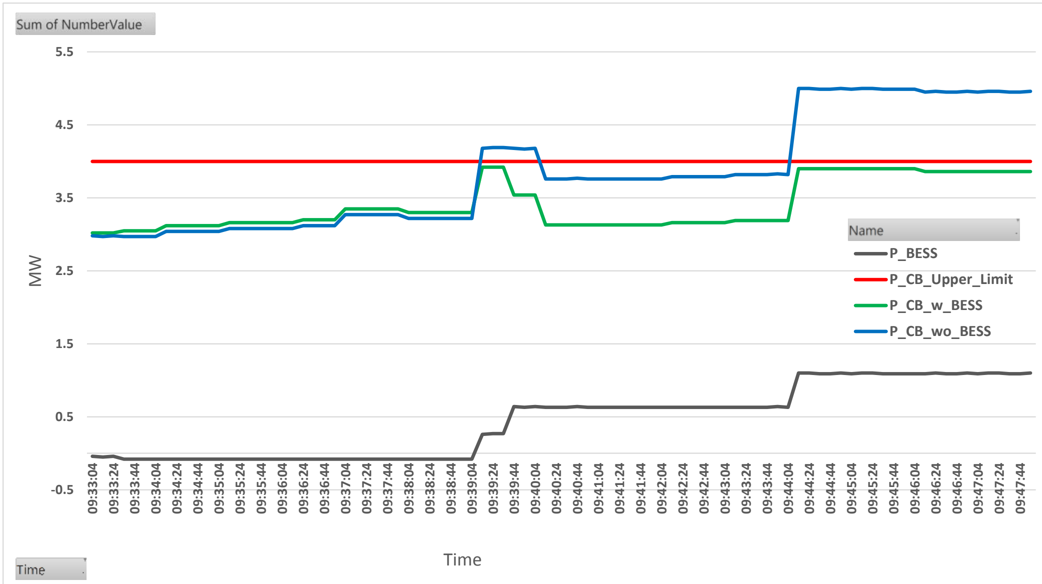

Figure 2-62. Real power flow through feeder CB with and without BESS contribution (Case 10.2)

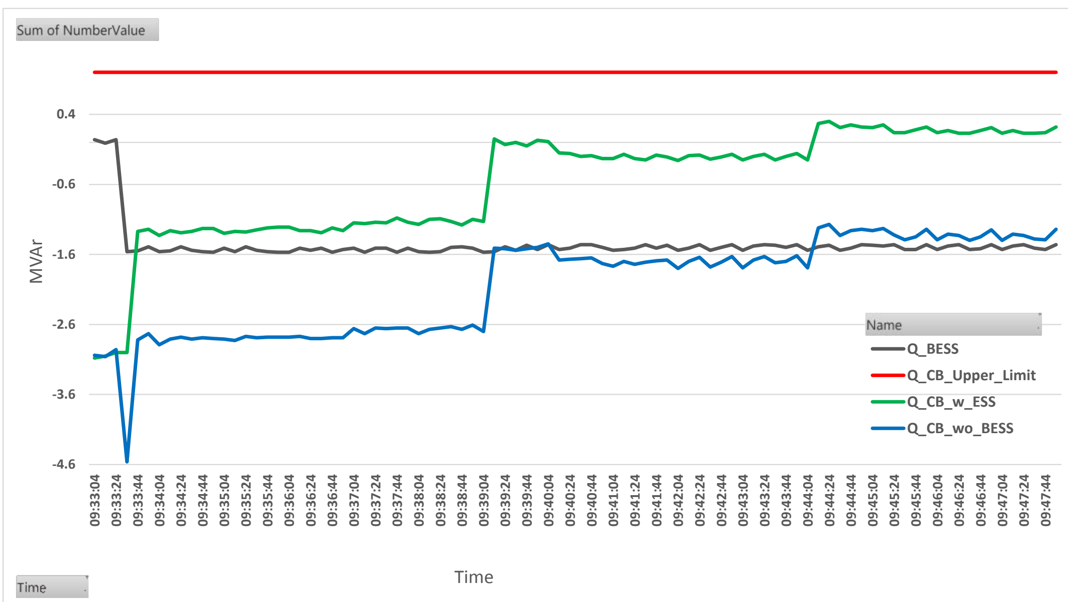

Figure 2-63. Reactive power flow through feeder CB with and without BESS contribution (Case 10.2)

Anti-islanding protection tests were conducted to determine how long it will take to disconnect a DER from the circuit subsequent to an islanding situation, using IEC 61850 communication platform (GOOSE). Thus, the time between the instant the CB opens until de-energization of the BESS is calculated for several test scenarios. These results are tabulated in the following table for five tests:

Table 2-30. Anti-islanding test cases with IEC 61850

Run	Round trip time (ms)	Remark
1	392.1	BESS discharging, and RTAC is in the loop
2	392.3	BESS discharging, and RTAC is in the loop
3	491.4	BESS discharging, and RTAC is in the loop
4	372.8	BESS charging, and RTAC is in the loop
5	412.1	BESS charging, and RTAC is in the loop
Mean	**412.2 (ms)**	

Table 2-30 shows promising results for an IEC 61850-based anti-islanding protection scheme. This is worth noting that the results of Table 2-30 are for the case where substation controller (RTAC) is in the loop (to change the control mode[21]) and, thus, it is not a fully peer-to-peer communication. It is expected that a peer-to-peer communication can further decrease the operating time (approximately to half). However, even with the existing setup, an IEC 61850-based scheme is about 4 to 5 times faster than an OpenFMB-based one.

As mentioned earlier, a set of tests were also conducted to compare the round trip time of the MMS communications with DNP3 communications, when utilized between the substation gateway and SCADA. Figure 2-64 shows the overall system setup for comparing these two communication protocols (between SCADA system and substation controller). As shown in this figure, a software interface or a middleware (Triangle software) has been employed between the substation gateways and SCADA as a converter for traditional SCADA system. The middleware is used for both test scenarios (MMS and DNP3) to make the test conditions as similar as possible.

To remove the variable impact of the latency associated with communications downstream of the Substation Controller, the downstream devices were bypassed as shown in Figure 2-65 below. Both DNP 3.0 and MMS messages were internally looped in the substation controller. The round trip times for both setpoints and commands were measured with MMS and DNP3 communications in place, separately.

Table 2-31 reports a summary of results for several test cases executed to calculate the round trip times of DNP3 and MMS communications. It is evident from the results that the difference between the response times are negligible (2.463 ms for DNP3 vs 2.503 ms for MMS). It should, however, be acknowledged that the engineering process for MMS communication protocol is simpler that that with DNP3 communication protocol (assuming a system with native support for IEC 61850 is available).

[21] Since there was no access to the CB of the BESS, control mode change has been selected as an alternative option. However, authors acknowledge that this may slightly affect the final results.

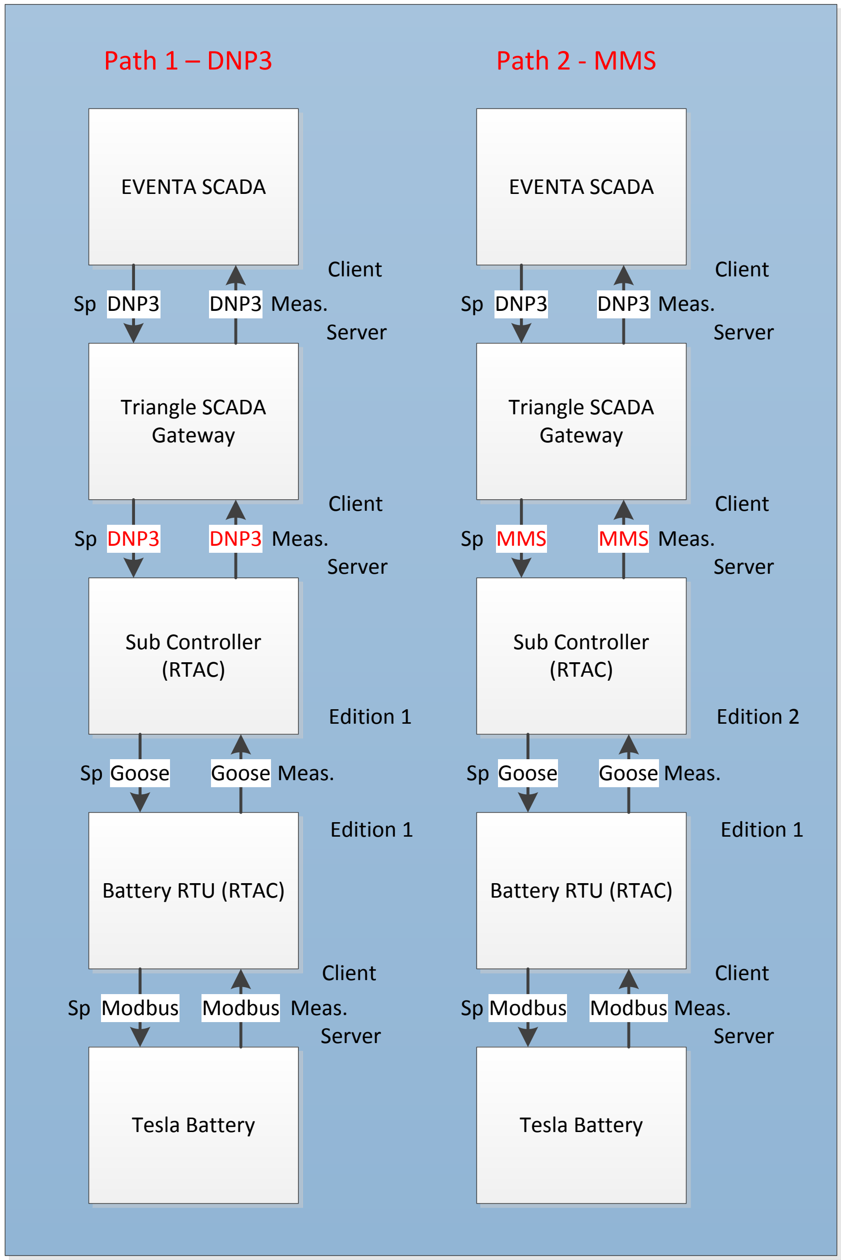

Figure 2-64. Overall system setup for comparing MMS and DNP3 communication protocols

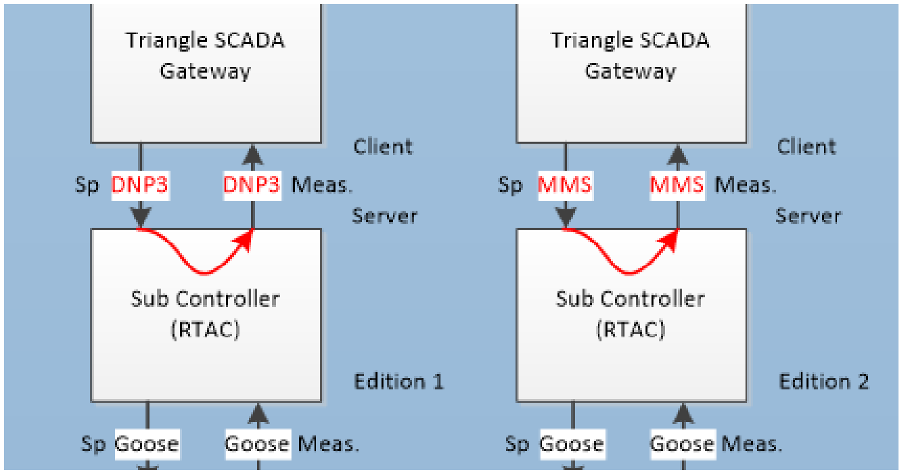

Figure 2-65. Test condition for comparison between MMS and DNP3 protocols

Table 2-31. Test results round trip time of MMS and DNP3

Data Point Name	Event Time Stamp	Time (ms)	Loop Time (ms)	Event Time Stamp	Time (ms)	Loop Time (ms)
	DNP3			MMS		
RTAC.BattPSp_Batt1	Nov 02 2017 17:41:50.568	63710.568	2.787	Nov 02 2017 13:14:35.977	47675.977	2.884
RTAC.BattPmeas_Batt1	Nov 02 2017 17:41:53.355	63713.355		Nov 02 2017 13:14:33.093	47673.093	
RTAC.BattPSp_Batt1	Nov 02 2017 17:41:38.713	63698.713	2.641	Nov 02 2017 13:14:24.990	47664.99	2.584
RTAC.BattPmeas_Batt1	Nov 02 2017 17:41:41.354	63701.354		Nov 02 2017 13:14:22.406	47662.406	
RTAC.BattPSp_Batt1	Nov 02 2017 17:41:28.472	63688.472	2.865	Nov 02 2017 13:14:12.994	47652.994	2.581
RTAC.BattPmeas_Batt1	Nov 02 2017 17:41:31.337	63691.337		Nov 02 2017 13:14:10.413	47650.413	
RTAC.BattPSp_Batt1	Nov 02 2017 17:41:13.291	63673.291	2.086	Nov 02 2017 13:14:02.012	47642.012	2.423
RTAC.BattPmeas_Batt1	Nov 02 2017 17:41:15.377	63675.377		Nov 02 2017 13:13:59.589	47639.589	
RTAC.BattPSp_Batt1	Nov 02 2017 17:41:01.673	63661.673	1.664	Nov 02 2017 13:13:29.976	47609.976	2.435
RTAC.BattPmeas_Batt1	Nov 02 2017 17:41:03.337	63663.337		Nov 02 2017 13:13:27.541	47607.541	
RTAC.BattPSp_Batt1	Nov 02 2017 17:40:49.625	63649.625	1.72	Nov 02 2017 13:13:18.990	47598.99	2.776
RTAC.BattPmeas_Batt1	Nov 02 2017 17:40:51.345	63651.345		Nov 02 2017 13:13:16.214	47596.214	
RTAC.BattPSp_Batt1	Nov 02 2017 17:40:33.369	63633.369	1.988	Nov 02 2017 13:13:04.975	47584.975	2.425
RTAC.BattPmeas_Batt1	Nov 02 2017 17:40:35.357	63635.357		Nov 02 2017 13:13:02.550	47582.55	
RTAC.BattPSp_Batt1	Nov 02 2017 17:39:14.849	63554.849	2.486	Nov 02 2017 13:12:54.991	47574.991	2.897
RTAC.BattPmeas_Batt1	Nov 02 2017 17:39:17.335	63557.335		Nov 02 2017 13:12:52.094	47572.094	
RTAC.BattPSp_Batt1	Nov 02 2017 17:38:44.145	63524.145	3.193	Nov 02 2017 13:12:42.005	47562.005	2.271
RTAC.BattPmeas_Batt1	Nov 02 2017 17:38:47.338	63527.338		Nov 02 2017 13:12:39.734	47559.734	
RTAC.BattPSp_Batt1	Nov 02 2017 17:38:23.393	63503.393	1.902	Nov 02 2017 13:12:32.128	47552.128	2.988
RTAC.BattPmeas_Batt1	Nov 02 2017 17:38:25.295	63505.295		Nov 02 2017 13:12:29.140	47549.14	
RTAC.BattPSp_Batt1	Nov 02 2017 17:38:00.559	63480.559	2.752	Nov 02 2017 13:12:22.098	47542.098	2.307
RTAC.BattPmeas_Batt1	Nov 02 2017 17:38:03.311	63483.311		Nov 02 2017 13:12:19.791	47539.791	
RTAC.BattPSp_Batt1	Nov 02 2017 17:37:39.080	63459.08	2.206	Nov 02 2017 13:12:10.085	47530.085	1.953
RTAC.BattPmeas_Batt1	Nov 02 2017 17:37:41.286	63461.286		Nov 02 2017 13:12:08.132	47528.132	
RTAC.BattPSp_Batt1	Nov 02 2017 17:37:24.785	63444.785	1.512	Nov 02 2017 13:11:58.060	47518.06	2.022
RTAC.BattPmeas_Batt1	Nov 02 2017 17:37:26.297	63446.297		Nov 02 2017 13:11:56.038	47516.038	
RTAC.BattPSp_Batt1	Nov 02 2017 17:37:13.465	63433.465	3.853	Nov 02 2017 13:11:46.061	47506.061	2.776
RTAC.BattPmeas_Batt1	Nov 02 2017 17:37:17.318	63437.318		Nov 02 2017 13:11:43.285	47503.285	
RTAC.BattPSp_Batt1	Nov 02 2017 17:37:05.986	63425.986	1.311	Nov 02 2017 13:11:32.081	47492.081	2.363
RTAC.BattPmeas_Batt1	Nov 02 2017 17:37:07.297	63427.297		Nov 02 2017 13:11:29.718	47489.718	
RTAC.BattPSp_Batt1	Nov 02 2017 17:36:54.343	63414.343	2.952	Nov 02 2017 13:11:18.103	47478.103	3.032
RTAC.BattPmeas_Batt1	Nov 02 2017 17:36:57.295	63417.295		Nov 02 2017 13:11:15.071	47475.071	
RTAC.BattPSp_Batt1	Nov 02 2017 17:36:44.487	63404.487	2.813	Nov 02 2017 13:11:06.094	47466.094	3.107
RTAC.BattPmeas_Batt1	Nov 02 2017 17:36:47.300	63407.3		Nov 02 2017 13:11:02.987	47462.987	
RTAC.BattPSp_Batt1	Nov 02 2017 17:36:33.689	63393.689	3.596	Nov 02 2017 13:10:52.099	47452.099	2.557
RTAC.BattPmeas_Batt1	Nov 02 2017 17:36:37.285	63397.285		Nov 02 2017 13:10:49.542	47449.542	
Average Time (ms)	2.463			2.503		

2.8.11.4 Findings

The following is a list of findings for the DCLM use case:

- IEC 61850 communication protocol can enable effective utilization of DERs to control the power flow through the feeder breaker on a real-time basis, considering load and (renewable) generation variations. Also, the results of several tests showed that, for supervisory control actions when time responses are not very critical, both OpenFMB and IEC 61850 can provide a communication platform to achieve satisfactory performances.
- Based on the results of anti-islanding tests, it can be concluded that IEC 61850 communication platform enables very fast actions to time-critical applications (such as system protection).
- Comparing the MMS and DNP3 communication for data monitoring and supervisory actions shows that
    - The response times of these two communication protocols are comparable (no significant difference was observed).

- Since the data point are available in an IEC 61850-base system, the mapping between the substation gateway and SCADA is relatively simple with MMS (as compared to DNP3). However, any change in the number of data point should be done through the substation configuration tool (SCT).

2.8.12 Use Case 11: Volt-var control via OpenFMB

2.8.12.1 Problem statement

Granular reactive power management through DERs as well as localized secondary voltage control with static voltage regulators, such as GridCo devices, can provide potential solutions to voltage fluctuations in distribution circuits dominated by DERs. The secondary voltage control devices are deployed at any location that (i) there is a need for voltage quality enhancement and/or (ii) there are residential and/or small commercial PVs and BESSs connected to a service transformer. However, the setting of these devices should be defined centrally to ensure optimum system performance.

Two major challenges to achieve this objective in DER-dominated circuits are:

(1). Control and operation of large number of DERs that are distributed along the circuits, and
(2). Remote communications with field DERs and secondary static voltage regulators.

2.8.12.2 Description and objectives

The main objective of this use case is to investigate capabilities of OpenFMB communication platform for managing the communications among various field devices (primarily, DERs and secondary GridCo units). The new architecture should be able to enable peer-to-peer communications in a coordinated and standard fashion. Field devices with various communication protocols are included in the use case to evaluate and demonstrate functionalities of OpenFMB in data exchange and traffic (data flow) control.

This use case incorporates development of an OpenFMB communication platform for monitoring and control of DERs and secondary devices on distribution circuits. The communication capabilities of the DER are also used to change their reactive power (Q) setpoints in coordination with load variations and changes in circuit conditions. The voltage and reactive power setpoints for secondary circuits are provided through control center operator.

The proposed test setup for this use case includes OpenFMB based field monitoring, communications, and data management with multiple devices, including:

- Interface to DSO though a RAMCO device,
- Peer-to-peer communications and monitoring of circuit loading through a CB relay,
- Peer–to-peer communications, monitoring and control of a utility-scale energy storage system, installed on the circuit under investigation downstream of the CB,
- Communications and control command exchange with a GridCo device dedicated to manage voltage, reactive power, and DERs on a secondary system that has multiple DERs[22].

[22] GridCo interface is done through a Localized Residential Aggregator and Monitor (LRAM) at service transformer.

This use case deals with reactive power management of one BESS unit, and voltage/reactive power control of one set of secondary systems. The Gridco device manages voltage and reactive power of secondary system, through a localized residential aggregator and monitor (LRAM) controller.

A high-level system diagram including main components involved in the OpenFMB DELCAM use case is illustrated in Figure 2-66. The dashed lines shows other communication paths that exist, but are not studied in this use case. It is noted that, as opposed to Use Case 9 (Figure 2-57), communication with one of the GridCo devices is essential in this use case.

2.8.12.3 Test cases and results

The goal of this use case is to effectively control DERs and secondary static voltage regulators for improved voltage profile within distribution circuits. In particular, the reactive power setpoint of the BESS as well as voltage reference setpoint of the GridCo device are controlled in order to regulate feeder voltage at both primary and secondary levels, respectively.

The test cases listed in Table 2-32 were conducted to evaluate the performance of this use case and to ensure enhanced operation of the system using OpenFMB communication platform. In addition to load and (renewable) generation variations, the test cases consider transient events such capacitor bank tripping to thoroughly examine the use case. While the results of a selected number of cases are presented and briefly discussed in this section, the results of additional tests cases are provided in Appendix D.

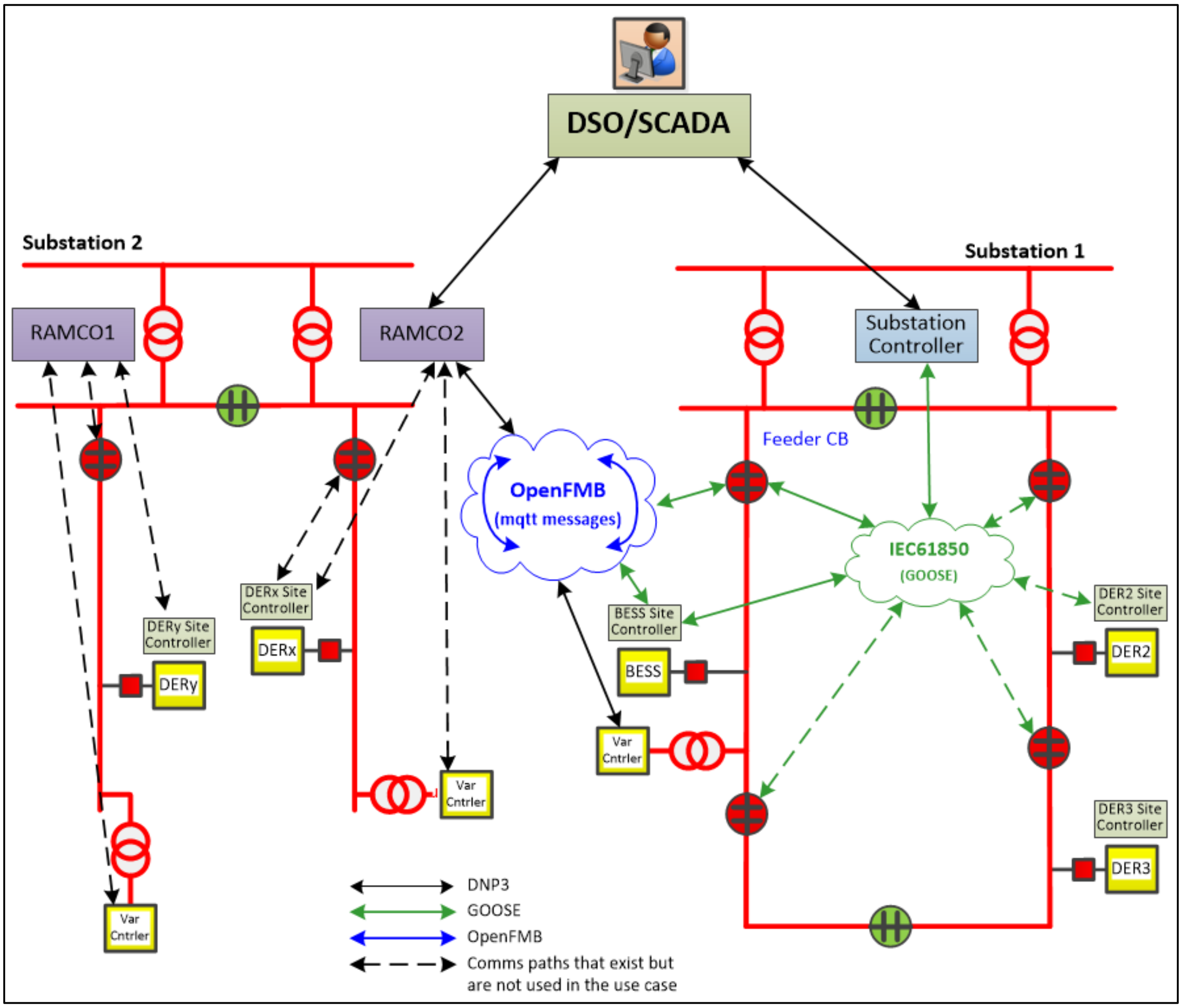

Figure 2-66. A high-level system diagram and data flow for VVM use case

Table 2-32. VVM test cases

Case #	Description	Remark
11.1	DSO setpoints are zero, and no power adjustment is requested; Load variations and PV variations are applied; Voltage are at normal range (120V for GridCo). GridCo has pf =1, Voltage and Q control mode CB power flow follows the changes in the load and PV	
11.2	DSO sends initialization for new mode, and setpoints for Interval 1 Interval 1 (early morning): load is the range of 4 to 6 MW PV production forecast is around 1 to 2 MW Voltage reduction by 2%	Low PV profile (1-2 MW) and High Load profile (4-6 MW); voltage reduction command (2%) was sent 4 minutes after; CCR2-932CW was then tripped;
11.3	Interval 2 (noon time frame): Load is the range of 2 to 3 MW, and PV production is strong and expected in the range of 4 to 6 MW Start with voltage reduction by 4% (to avoid overvoltage)	High PV profile (4-6 MW) and Low Load profile (2-3 MW); voltage reduction (4%) was issued 3 minutes after; CCR2-932CW was turned on later; then, CCR2-932CW and CCR2-921CW were tripped; voltage increase (2%) was sent 13 minutes after;
11.4	Interval 3 (evening time frame): load is the range of 4 to 6 MW, and PV production forecast is low Voltage increase by 2%	No PV profile and High Load profile (4-6 MW); voltage increase (2%) was sent 5 minutes after; CCR2-919CW was tripped later.

The following set of transient incidents were also applied to the system in this case to further evaluate the response of the control system:

- Voltage reduction command (4%) at 16:50
- Connect CCR2-932CW Cap Bank at 16:53
- Trip CCR2-932CW and CCR2-921CW Cap Banks at 16:55
- Voltage increase command (2%) at 16:59

For some of the scenarios described above (e.g., Points 1 and 2), the BESS has reached its maximum reactive power capacity (–1.6 Mvar) and, thus, it cannot contribute further. However, when required, the RAMCO logic calculate the additional reactive power required (Delta_Q) and send it back to the DSO (note gray line in Figure 2-67). It is also observed that when the voltage increase command is sent to the RAMCO (from DSO), the RAMCO has adjusted BESS setpoint to make a leading power factor at the feeder level (see red line around 16:59, Figure 2-67).

Figure 2-68 shows the reference and measured voltage of the secondary voltage regulator (GridCo device) for Case 11.3. The figure indicates that the static voltage regulator has successfully regulate the voltage of the secondary side of the service transformer.

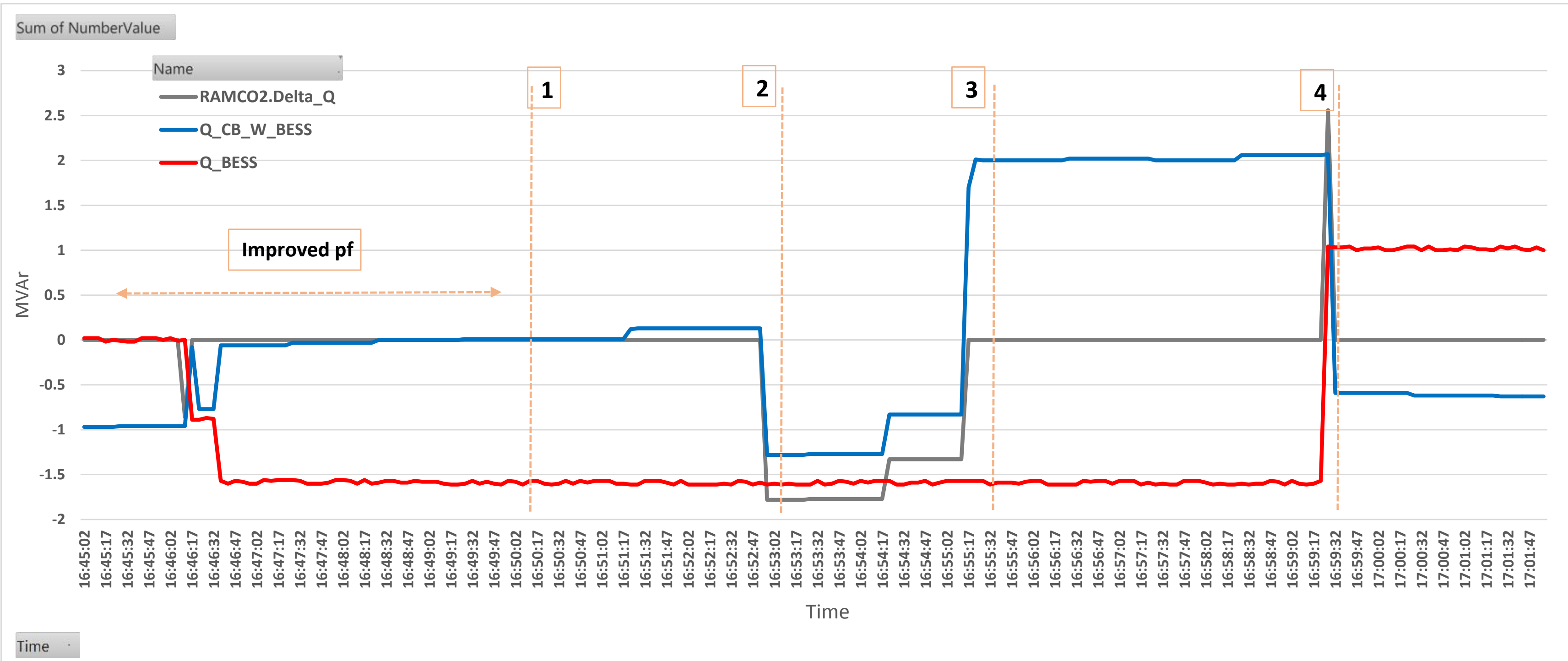

Figure 2-67. Reactive power flow through feeder CB with and without BESS contribution (Case 11.3)

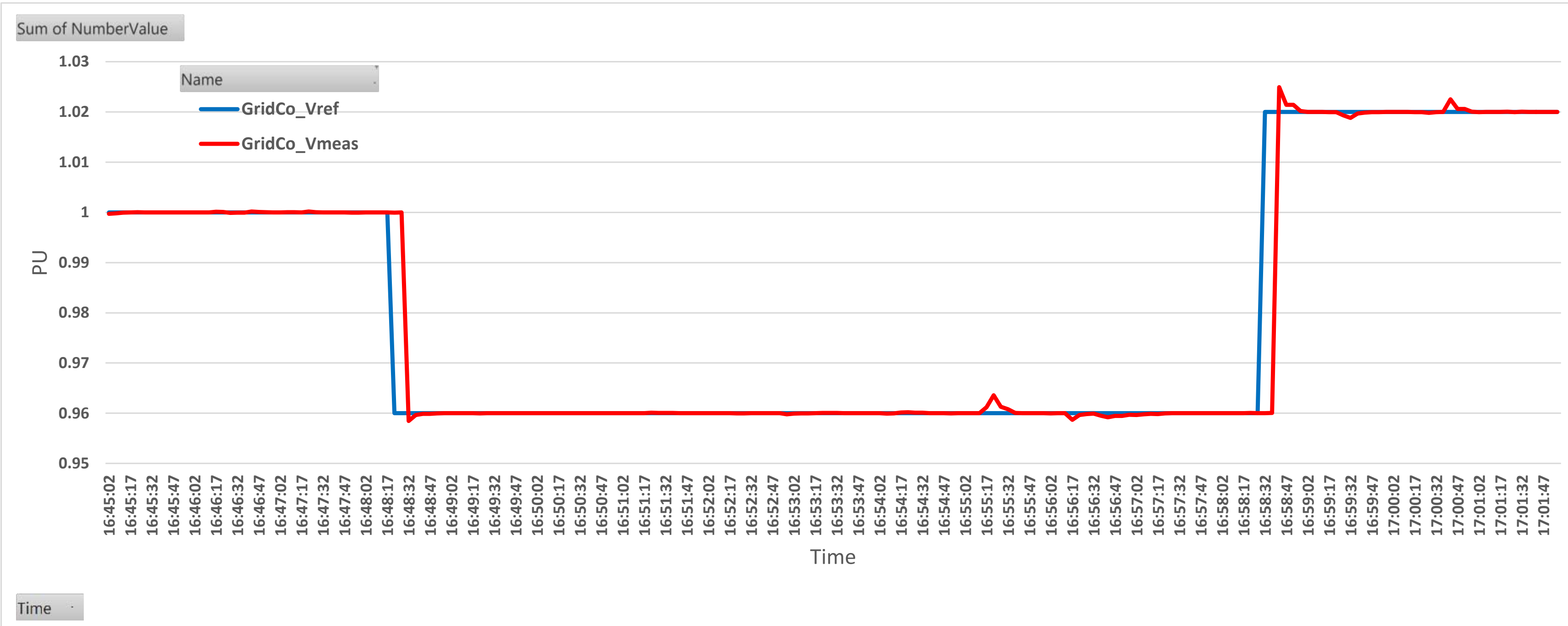

Figure 2-68. Voltage reference for GridCo device (Case 11.3)

2.8.12.4 Findings

The following is a list of findings for the DCLM use case:

- OpenFMB framework can enable effective utilization of DERs and secondary static voltage regulators to control the voltage of distribution feeders on a real-time basis, considering load and (renewable) generation variations.
- The use of OpenFMB framework enables an integrated control system where field and substation devices with various communication protocols can be included in the control scheme (resulting in a more optimized control).
- Open FMB enables interoperability with field devices and systems operating in the grid. The framework is compatible with multiple data models, communication protocols, and technologies. Further, the requirements of this application (use case) can be met using OpenFMB as the communication platform.

2.9 Phase 4 – SDG&E Internal Project Work Prior to Project Conclusion

Task 1 – Comprehensive Final Report

Objective – Develop comprehensive final report

Approach - Develop a comprehensive final report based on the CPUC EPIC Final Report guideline developed by the three IOUs. The report presented in this document follows the outline developed by the IOUs to share the results of the project undertaken.

Output – Comprehensive final report as presented in this document.

Task 2 – Technology Transfer

Objective – Develop technology transfer plan to share results with all stakeholders.

Approach – A technology transfer plan was developed to share the results with SDG&E stakeholders and with other stakeholders in the industry that would benefit from this pre-commercial demonstration

Output – Technology transfer plan as documented in Section 4.2 of this report.

3 FINDINGS

The subsections that follow summarize the primary findings from both phases of the project.

3.1 Challenges observed in SDG&E's current architecture

The primary architectural challenges observed were:

- **Parallel communication paths**. In some instances there are multiple communication paths from control center entities to the same physical location stemming from restrictions of the existing communication infrastructure, and desire to separate daily operations from experimental and pilot technologies.
- **Time domain separation**. There are functions that require a certain speed of response that are being performed at locations in the architecture that make it challenging to obtain deterministic levels of performance.
- **Centralized decision making**. The architecture is highly centralized, which places restrictions on the speed of response and limits the ability to perform distributed autonomous actions.
- **Communications infrastructure**. The absence of a high speed communication backbone to substation and field devices places restrictions on the type of devices and data that can be integrated into the system.
- **Duplication of functions**. The planned architecture contains some duplication of functions, like Volt/var control for example, with multiple entities identified as being responsible for this application. This may be just a matter of finalizing the correct "owner" for the application, but having the same or similar application in multiple locations is problematic.
- **Roles and responsibilities**. The existing architectural documentation did not map functions to stakeholders and responsible parties. The RACI analysis for this Smart Grid Architecture Demonstration Project has now established a map of existing roles and responsibilities.
- **DER integration**. DER devices are integrated into the architecture but more as one-offs or pilots than a large scale deployment.
- **Scalability**. There is a concern whether the architecture as currently envisaged can scale adequately, both in terms of increased DER penetration as well as the ability to manage more autonomous functions given the highly centralized nature of the design.

3.2 Most appropriate architectural model for SDG&E's future use

The following architectural models were examined:

- CEN-CENELEC-ETSI Smart Grid Coordination Group's SGAM architecture
- IEC's TC-57 reference architecture
- GridWise Architecture Council's Gridwise Architecture
- EPRI's Integrated Energy and Communications Systems Architecture (Intelligrid) architecture
- PNNL/DOE's Grid Architecture Initiative
- SCE, IBM, and Cisco's Smart Grid Reference Architecture
- IEEE's P2030
- NIST/SGIP's Smart Grid Conceptual Model
- Microsoft's Smart Energy Reference Architecture

The SGAM model was selected as the best fit for SDG&E because of its capability to relate the technical layers with business goals, as well as define use cases in relation to their impact on all key layers. The main reasons for choosing SGAM were as follows:

- SGAM was evaluated as the most comprehensive reference architecture for use case development because it incorporates business, function, information, communication, and component layers.
- SGAM builds on existing architectures such as the NIST Conceptual Model (NIST 2009), the GridWise Architecture Framework (GWAC 2008), as well as architecture standards like TOGAF and Archimate, which allows reuse of existing models
- It is possible to map the TC57 in the communication and information layers of SGAM.
- The relatively recent NIST Special Publication 1108r3 (September 2014), advocates the SGAM reference architecture as "a template for architects to follow while building aspects of a smart grid architecture, regardless of an architect's specialty (such as areas of transmission, distribution, IT, back office, communications, asset management, and grid planning." So that endorsement lent additional credibility to the selection.

3.3 Trends in communications standards development

The industry has many standards that exist among several standards development organizations that may be applicable to multiple layers of the power systems architecture. The key goal is to identify the standards that can be tailored to support SDG&E's specific requirements and use cases. The NIST/SGIP activities maintaining the Catalog of Standards, as well as IEC TC57 work provides a well-tested source of standards for consideration in SDG&E's distribution system architecture.

A key standard is the IEC 61850 protocol suite. The extent of harmonization efforts that have included IEC 61850 show that the suite is becoming a key building block in the future smart grid architecture.

3.4 Roadmap for proposed architecture implementation

A 10-year implementation time frame is expected for near full deployment. The general activities required to migrate to the proposed architecture in the context of the SGAM layers include:

- **Component layer***:* Mitigate parallel operations and facilitate more distributed control through implementation of pro-active direct SCADA control incorporating DERMS and peer-to-peer field device communication. A DSO server may be added to negotiate DER integration and control.
- **Communications applications layer**: Implement the IEC 61850 standard for transport and applications interfaces to support use cases (including IEC 61850-8-1 (GOOSE), IEC 61850-7-2). IEC 61850 also utilizes adapters capable of interfacing other standard protocols such as DNP3, MultiSpeak, C37.118, etc. Interfaces to legacy protocols such as SCOM are to be determined.
- **Information layer**: Implement standardized approach to information exchange utilizing IEC 61850, IEC 61968/61970, etc. This would include document/drawing files, XML files, IEC 61850-7-3, 7-4 Object Models, IEC 61850-6 Engineering, especially to support use cases.
- **Functional layer**: Modify existing baseline Distribution Operations functions to account for changes driven by more direct SCADA control and more prevalent use of DER integration at the feeder level:
  - Asset Condition-based Monitoring

        - Designing, Engineering, building, commissioning, and maintaining IEC 61850 compliant protection and automation systems
        - Maintenance testing of IEC 61850 compliant relay/IED
    - Feeder Protection
        - Breaker failure scheme with GOOSE messaging
        - Automatic Transfer scheme using GOOSE messages
        - Protection Coordination with IEC 61850 (including anti-islanding protection of DERs, reclosing/relaying operation, enhanced operation of feeder protection
    - DER Control (Feeder connected)[NOTE: this is in addition to existing Distribution Operations function of DER control(generation/storage)
        - Remotely change control mode of DER (IEC 61850)
        - Using multiple large scale DERs, correct feeder power factor/improve feeder voltage; coordinated use of ride-through capabilities to enhance system performance under network faults and/or transient disturbances
    - Load management (emergency)
        - Effective utilization of DER contributions to offset customer loads
    - System Load Forecasting (high level)
        - Incorporate DER resources into day-ahead and short-term forecasts
- **Business layer:** Review baseline roles and responsibilities and consider business area realignments relating to new functions from DER use cases, and potential other modifications based on gaps discovered during baseline RACI analysis:
    - Definition of market services including DSO responsibilities
    - Siloed operations in alarm processing, data management, data analytics
    - For a single function, assignments of accountability or responsibility to multiple entities

Any legacy or proprietary protocols or information models should be transitioned to a more standards based approach over time to realize the full economies and advantages of a standardized reference architecture.

3.5 Engineering an IEC 61850 system

The test cases performed in use case 1 comparing the tasks required to construct an IEC 61850-based solution versus a traditional solution using DNP 3.0 with hardwired interconnections between IEDs show that, overall, the steps are similar. However, there is a significant difference in the effort to engineer and test the two systems. The IEC 61850 approach relies on virtual interconnections and offers the ability to test the logic and automation as they are being engineered and parametrized, as opposed to waiting for physical switchgear to be assembled and tested. This “real-time” testing during the engineering process reduces the time required for factory and site testing, as well as that for equipment start-up and commissioning.

The configuration inheritance and use of descriptive data point naming supported by IEC 61850 (as opposed to the much more limited and opaque digital, analog and control input/output numbering supported by conventional protocols) also makes the tasks of configuring gateways and substation Human Machine Interfaces (HMIs) considerably easier when contrasted to the conventional approach.

However, use case 1, and the overall process of configuring the system for the configuration employed on this project with IEDs from multiple different vendors, was still not a simple task. There were several issues related to interoperability between the devices that needed to be solved that added to the engineering effort that would not have been required on a simpler, conventional system. The added features provided by IEC 61850, specifically those related to the peer-to-peer GOOSE message exchange, come at the cost of added configuration complexity. The issues encountered included the following:

- The configuration tools provided by the vendors of the various IEDs had widely different levels of capabilities in terms of being able to integrate data from other vendor's products. This led to a separate analysis on engineering tools that is presented in Appendix B.
- It was necessary to find a mechanism to document which IEDs were publishing which data via GOOSE, and which IEDs were subscribing for, and using, these data. In the absence of a tool that did this, the team created an Excel spreadsheet to document this matrix, but it was a non-ideal solution and more work is required in this area by the vendors. This is also addressed in Appendix B.
- Different vendors used different names to refer to the same data point. There are some areas where the standard is open to interpretation and implementations differ from one vendor to the next. There was even one instance of two IEDs from the same vendor having different names for the same data type.
- Initially, the project goal was to set up a fully functional IEC 61850 Edition 2 system following the latest implementation of the standard. Unfortunately, this proved impossible because some of the selected devices only supported Edition 1. In theory, Edition 2 devices will interface with Edition 1 devices (although the reverse is not true). Unfortunately, reality and theory proved to be two different things and numerous problems were experienced, especially in the area of GOOSE messaging and set-up. As a result, the project was forced to "downgrade" some devices to Edition 1 to ensure interoperability.
- One of the vendors had an issue that any changes to the publisher/subscriber setup required the setup to be cleared and re-imported, but this would also erase some of the communication parameters, necessitating re-entry.
- Some IEDs were incapable of subscribing to analogue points, making it impossible to use them in applications where the IED had to be able to monitor analogue values to make decisions and take actions.
- One of the vendor's configuration tool created a configuration output file (the CID file) that contained not only selected data set to be published, but all available data. Several other bugs were detected and communicated to the vendor, leading to the conclusion that the vendor had not deployed many (any?) IEC 61850 IEDs to date.

As described above, the project team experienced several challenges related to inter-vendor interoperability. The team also observed limitations in some of the vendor configuration tools that made the engineering process more challenging than it needed to be. This triggered further analysis into the state of the industry on IEC 61850 interoperability – the results of which are provided in Appendix B and summarized in the section that follows.

3.6 IEC 61850 Interoperability

The 2017 UCA Interoperability (IOP) test session took place at the Marriott Hotel at the Convention Center in New Orleans, LA, October 14-19, 2017. It was the third of a series of biannual IOP sessions. There were over 200 attendees – vendors, utilities, laboratories, and institutions as test participants or witnesses. The sponsor of IOP events is the UCA International Users Group (UCA IUG), a mutual-help consortium of IEC 61850 users, product vendors, and standard developers. A description of the proceedings is provided in Appendix A, and summarized below:

- The 2017 interoperability test demonstrated a broad offering of IEC 61850 products and engineering tools which were successfully integrated into typical system applications.
- Integration required moderate levels of engineering effort, creating the appearance of advanced and maturing product development, but with some products in beta state.
- Ethernet network configuration problems were the most challenging detractor from interoperability test progress. This demonstrates a focus topic for utility users of IEC 61850. Notably, it appears that pre-test network engineering project management faltered before this IOP, with infrastructure problems delaying progress in IEC 61850 application integration. This comprises a major lesson for utility users of IEC 61850.
- IOP included testing for other services and capabilities which generally worked well:
    - Merging units and sampled value (SV) communications per 61850-9-2 and UCA 9-2 LE, with a serious remaining ambiguity about sample timing synchronization to be resolved.
    - IEC TR 61850-90-5 WAN-routable GOOSE and SV (R-GOOSE and R-SV). Both are used for wide-area synchrophasor transport as well as GOOSE for control. Authentication feature not tested.
    - Time synchronization via IEEE 1588 PTP and PPS in addition to IRIG-B.
    - Network security policy implementations.
- Product vendors and third-party tool developers demonstrated a variety of tools which showed an advanced stage of development, apparently close to or at commercial product refinement.
- Tools offered a variety of functions including IEC 61850 system configuration (GOOSE and MMS client-server association), network traffic monitoring and testing, product configuration and configuration-file format conversion, SCL file analysis or validation, and product communications simulation (multiple devices simulated within one tool).
- IOP discussions highlighted tools for and means of viewing and documenting GOOSE connections which are convenient, and not based on hand-built Excel spreadsheets. These deserve trials in practical projects.

The interoperability tests showed that large and complex systems utilizing multiple vendor's products and tools can be engineered and made operational, but require expert knowledge. There were several configuration tools on display that showed good progress on solving some of the engineering challenges experienced by the project team in building the test system. Some of these tools are discussed further in Appendix B.

3.7 Testing an IEC 61850 system

For maintenance purposes – replacing existing/failed IEDs, logic change/upgrade, or adding new IEDs to the system – condition-based testing is performed on IEDs to confirm their proper operation. To do this, the test engineer must isolate the IED under test from the system to avoid any undesired breaker operations during the testing process. In the case of wired-connected systems, the test engineer opens test switches to perform maintenance tests. However, the situation is much different in an IEC 61850 environment, where the isolation of the relay/IED can be done through communications.

The IEC 61850 standard provides a mechanism that allows for the isolation of an IED for field testing purposes. In Edition 1, the interpretation of the mode and behavior of this feature was not described, and the implementation of this mechanism was only possible by configuring specific logic in the IEDs. Edition 2 of the standard addressed these short comings and clarified these “gray areas” by providing specific rules regarding the behavior of the different modes.

The test cases described in Use Case 2: Maintenance testing of IEDs, demonstrated how the use of the simulation, test and block modes of operation simplify the testing process. These modes enable the verification of application logic and correct operation of devices without impacting the rest of the system. The tests showed how the concept of “virtual test switches” provides an easy and quick way to isolate a device under test and thoroughly test it, all without the presence of any physical test switches.

3.8 Implementing a breaker failure scheme using IEC 61850

Use Case 3: Breaker failure scheme, demonstrated that a breaker-failure scheme could be easily implemented in an IEC 61850 system without the need for physical wiring. It furthermore showed that a breaker-failure scheme based on IEC 61850 GOOSE communication was more reliable than a wired implementation because “hidden problems”, like bad connections, are detected and alarmed in real-time – as opposed to being discovered after the fact when the breaker fails to operate.

3.9 Implementing an automatic transfer scheme using IEC 61850

Use Case 4: Automatic transfer scheme, demonstrated that an automatic transfer scheme could be implemented in an IEC 61850 system without the need to add any additional wiring. Over and above the conventional substation-based transfer scheme, the tests demonstrated how IEDs located on the feeder were also integrated into the transfer scheme and how transfer trip commands could be sent to the DER located on the feeder. As with the breaker failure scheme, the ability of the IEC 61850 based system to alarm on communication loss to participating devices, demonstrated how the system was able to detect and alarm on failures that would be hidden in the conventional approach.

3.10 Improving protection coordination using IEC 61850

Use Case 5: Improved protection coordination, provided several uses cases that demonstrated a protection scheme that used IEC 61850 to integrate data from substation and feeder protective relays was able to perform at least as well, and in some cases considerably better than the existing, conventional scheme. This included cases where the existing design took 1.5 seconds to clear a feeder close-in fault, while the improved awareness provided by the IEC 61850 design allowed the same fault clearing to be done in 60ms. A resistive close-in fault that took 3.5 seconds to clear in the current scheme, was shown to clear in 80 ms using IEC 61850. Moreover, the use case detected a coordination problem with the existing scheme for an end-of-line fault which the IEC 61850 design was able to correct.

3.11 Integrating DER devices into an IEC 61850 scheme

Use Case 6: DER control mode change, demonstrated how the control modes of DER devices can be controlled when they are integrated into an EIC 61850 system. At the time the tests were conducted there were no commercially available DERs that provided native support for the IEC 61850 communication protocol. It was therefore necessary to use a gateway between the DER and other equipment to integrate them into the IEC 61850 system. When selecting a gateway is it imperative that the device be able to subscribe to both analog and digital values which, as was discovered on this project, is not always the case.

The specific application and required speed of response will dictate which of the two IEC 61850 messages services, GOOSE or MMS, should be used for integrating DERs into the distribution circuit. For highly time critical application the peer-to-peer communications supported by GOOSE is the appropriate response. For less time critical applications either GOOSE or MMS are feasible options.

The capabilities of DER devices differ and this impacts the feasibility of some applications. For example, the battery used in this study did not support V-Q droop mode, while the SMA inverter did not support modifying the upper and lower voltage thresholds in the VQ-droop mode – both of which limited the functionality that could be implemented.

3.12 Using DER devices for grid support in an IEC 61850 scheme

Use Case 7: Grid support using DERs, demonstrated that peer-to-peer communications among DERs and other protection and control equipment was able to enhance distribution system operation through improved power factor at the substation level, obtained by increased involvement of DERs, and enhanced voltage profile, through proper DER reactive power contribution.

The direct communication between DERs and the downstream protective device(s) enabled coordination between system protection and the low-voltage ride-through (LVRT) capability of the DERs. This prevented unnecessary operation of the DER and was able to improve both the security and dependability of DER anti-islanding protection.

3.13 Emergency load management in an IEC 61850 scheme

Use Case 8: Emergency load management tests, demonstrated that using IEC 61850, DERs could be effectively employed to address load shedding requests with minimum interruption to customers, that power flow through the transformer banks at the substation could be controlled on a real-time basis, and finally, reverse power flow could be managed through effective use of BESS while energy obtained from renewable resources was optimized.

3.14 OpenFMB versus IEC 61850 for integrating DER

Use Case 9: Dynamic emergency load control and management with DERs using OpenFMB and Use Case 11: Volt-var control via OpenFMB, explored the use of OpenFMB for several test cases. The testing demonstrated that the OpenFMB framework could be used to integrate DERs and control the voltage of distribution feeders on a real-time basis, considering load and (renewable) generation variations, but with several caveats:

OpenFMB is even more of a nascent technology than IEC 61850. At the time of testing there were no DER devices with native support for OpenFMB and as a consequence, protocol conversion was necessary. This involved using gateway devices to convert between Modbus, DNP3.0, IEC 61850 and OpenFMB's MQTT[23]. A side-by-side comparison of OpenFMB versus IEC 61850 was performed for one

[23] MQTT is a lightweight messaging protocol for small sensors and mobile devices, optimized for high-latency or unreliable networks.

specific application, and as would be expected, the IEC 61850 outperformed the OpenFMB by an order of magnitude because of the delays introduced by the protocol conversion in the OpenFMB set-up. Until native support is available, OpenFMB is not viable for any application requiring high-speed, protection-level response. In addition, the use of gateways obviates the purported simplicity of data exchange and configurability, so these benefits weren't observable in the test system.

Another finding related to the maturity of the available open-source firmware/software. The implementation of the publically available OpenFMB MQTT drivers was not an easy task and required significant development to get the system operational. The protocol has promise to assist in the integration of grid-edge devices, but lack of product availability made it clear that OpenFMB still has a way to go before being ready for operational deployment.

3.15 Using IEC 61850 between substation and simulated control center

Use Case 10: Dynamic circuit load management, included a test that contrasted the performance of DNP 3.0 and IEC 61850 for communications between a substation and a simulated control center. A direct comparison was difficult because the simulated control center did not offer native support for IEC 61850 and it was necessary to use a software gateway to convert from DNP 3.0 to IEC 61850. To make the comparison as equivalent as possible, a similar software gateway was used to convert DNP 3.0 back to DNP 3.0, thereby introducing the same order of intermediate delays. The tests showed little difference between the performance of the two systems. In this case, the MMS message service was used, which more closely aligns with the DNP 3.0, master/slave model (than would GOOSE), because MMS will be the IEC 61850 message service used between control center and substation when/if this becomes common practice. Given relatively comparable performance, one of the key differentiators between the two approaches will be the ease of configuration changes and the elimination of the complicated, time-consuming and error prone, point mapping required with the conventional SCADA protocol approach.

3.16 Cost comparison – IEC 61850 vs a conventional design

When doing a cost comparison of IEC 61850 versus a conventional approach, there are normally three different categories of costs and benefits that need to be examined:

- Those that impact the purchase price of the equipment and are directly related to IEC 61850
- Those that impact the purchase price of the equipment and involved design changes that are enabled by IEC 61850
- Those that result from reduction in utility labor in engineering, commissioning and the on-going operations and maintenance of the system enabled by the networked/connected features of the IEC 61850 system

In general terms, the business case for an IEC 61850 system, especially one that involves a process bus, is stronger for larger and more complex substation designs. This makes it simpler to make a business case for IEC 61850 in transmission system applications as opposed to distribution system applications. However, that certainly does not preclude the possibility of a positive business case for IEC 61850 in distribution applications.

In one study performed for a North American utility in the east, moving away from their traditional distribution substation design that specified large numbers of test switches, pilot lights, annunciators, meters, separate relay functions per IED, etc. to an “all-digital” IEC 61850-based design held the potential to deliver CAPEX savings of over 30%.

Other studies suggest a more modest CAPEX savings of between 10% and 20% are possible when reductions in the time required for engineering, testing, start-up, etc. are factored in. However, it is also true that the first few installations of an IEC 61850-based design will be considerably more expensive because of the learning curve and costs.

In many cases, the largest potential for savings came from implementing design changes that are not directly related to IEC 61850, but which are enabled by it.

There are savings to be gained in utility labor in the design, engineering, start-up, commissioning and ongoing maintenance phases. Some of the savings are relatively easily quantified while others are more speculative and are based on what-if scenarios like extent of changes during the pre-in-service date, and the number of substation events that occur post-in-service. Regardless, the data suggested that the added equipment costs of the IEC 61850 Substation Bus system are more than offset by the savings from reduction in utility labor.

Some of the design modifications represent a change in philosophy and utility practices. A phased commercial adoption process, including laboratory and test-site simulations and formal personnel training programs, is recommended to ensure acceptance of the changes by utility personnel and to optimally manage the process.

4 RECOMMENDATIONS AND NEXT STEPS

4.1 Recommendations regarding commercial adoption of the demonstrated architecture

The various use cases documented in this report comprehensively demonstrate that IEC 61850 is a robust standards platform that offers numerous advantages over conventional approaches. As such the recommendation is that SDG&E plan for deployment of the technology. However, the project also identified several interoperability challenges when integrating devices from different vendors, and the process of engineering and configuring the system was more complex that desired. It is therefore recommended that SDG&E implement a pilot project using IEC 61850 before considering any large scale deployment. The pilot project should be planned such that sufficient time exists to work through any interoperability issues. Aside from exploring the operational adoption of the standards, the pilot project should have several other objectives:

- Quantify costs and benefits, and then develop a cost-benefit analysis for wide-scale deployment
- Examine what changes to standard operating procedures are necessary to fully leverage the benefit of a digital substation.
- Use the pilot project as a training platform for engineering, testing and commissioning personnel.

Deploying IEC 61850 for applications involving feeder equipment and non-substation based DERs is more complex than those inside the substation boundary, and high-speed and reliable communications are a prerequisite. It is recommended that a pilot project that explorers the non-substation applications of IEC 61850 and allows for real-world testing also be undertaken. This EPIC project used a high speed wireless system that performed well in the lab environment, but it is recommended that additional testing be performed on a carefully selected substation and feeder combination and the performance evaluated over an extended period of time to ensure the maturity of the standards is such that system performance is consistent and reliable.

As noted, there are currently no DER devices that offer native support for IEC 61850, and any DER devices currently require gateways to integrate into an IEC 61850 system. As DER devices are released that fully support IEC 61850, it is recommended that these be lab tested on a test bed before deployment in the field. This test bed should be constructed to represent a typical substation/feeder configuration with the aim of performing interoperability testing as new devices are released. Once the devices prove capable of operating in the IEC 61850 system and supporting the required applications, they can be moved out of the lab and into a substation/feeder pilot.

Experiences on the project suggest that more investigation into the operational readiness of OpenFMB is required. The same testbed proposed for testing new IEC 61850-enabled DER could be used to perform proof-of-concept testing on OpenFMB devices as they become commercially available and fully evaluate the feasibility and benefits of wide-scale deployment.

As the natural next step, it is recommended to prepare a comprehensive business case for deployment of IEC 61850 in distribution substations and circuits for both protection and automation purposes. The use cases introduced and demonstrated in this project provide quantified basis to prepare a breakdown of all cost categories. In addition, the project has categorized the cost saving areas. Additional SDG&E

stakeholder participation will be needed to assign appropriate dollar values on the benefit categories and assess the benefits.

4.2 Recommendations for tech transfer of results from this EPIC project

The results of the project should be communicated to the industry at large. After posting this final report on the SDG&E public EPIC web site, its availability on the website should be widely announced. It is also recommended that technical papers be written that summarize the work and key findings. These papers should be submitted to appropriate industry conferences and technical journals to ensure the experience gained is shared with additional stakeholders. A comprehensive slide file should be used to present the project findings internally to SDG&E stakeholders and at appropriate external events.

5 METRICS AND VALUE PROPOSITION

5.1 Metrics

The following metrics were identified for this project and evaluated during the course of the pre-commercial demonstration. These metrics are not exhaustive given the pre-commercial demonstration approach for this project.

Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy

- Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)
    - Use of configuration inheritance and descriptive data point naming supported by IEC 61850 makes the task of configuring devices in substation and feeders considerably easier when contrasted to the conventional approach. Digitization of devices using IEC 61850 can potentially lower the barriers of adoption of newer technologies within the electric infrastructure.
- Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
    - The industry has many standards that exist among several standards development organizations that may be applicable to multiple layers of the power systems architecture. A key standard is the IEC 61850 protocol suite. The extent of harmonization efforts that have included IEC 61850 show that the suite has the potential of becoming a key building block in the future smart grid architecture that enable effective communication and interoperability of equipment connected to the electric grid.

Safety, Power Quality, and Reliability (Equipment, Electricity System)

The use of IEC 61850 in field could enable interoperability, improve protection coordination and provide effective information sharing between field devices and backend systems. The following sub-factors could be enhanced with the use of IEC 61850:

- Increase in the number if nodes in the power system at monitoring points
- Reduction in outage numbers, frequency, and duration.
- Reduction in system harmonics

5.2 Value Proposition

The purpose of EPIC funding is to support investments in R&D projects that benefit the electricity customers of SDG&E, PG&E, and SCE. The primary principles of EPIC are to invest in technologies and approaches that provide benefits to electric ratepayers by promoting greater reliability, lower costs, and increased safety. This EPIC project contributes to these primary and secondary principles in the following ways:

- Reliability – This project demonstrated the potential of improving reliability through implementing breaker failure, automatic transfer, protection coordination, and DER integration using IEC 61850. The use of digital signals over analog signals through the use of IEC 61850 has the potential to help improve reliability by providing relevant data for effective electric system operations.
- Lower Costs – The IEC 61850 approach relies on virtual interconnections and offers the ability to test the logic and automation as they are being engineered and parametrized, as opposed to waiting for physical switchgear to be assembled and tested. Utilizing IEC 61850 as the communication standard and engineering devices based on IEC 61850 digital models has the potential to lower costs for integration of devices and applications that can help utilities operate their electric infrastructure efficiently and in a cost effective manner.

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A. APPENDIX A – IEC 61850 TOOLS AND UCA 2017 INTEROPERABILITY TEST

A.1 Introduction

The 2017 UCA Interoperability (IOP) test session took place at the Marriott Hotel at the Convention Center in New Orleans, LA, October 14-19, 2017. It was the third of a series of biannual IOP sessions. There were over 200 attendees – vendors, utilities, laboratories, and institutions as test participants or witnesses.

The sponsor of IOP events is the UCA International Users Group (UCA IUG), a mutual-help consortium of IEC 61850 users, product vendors, and standard developers. The UCA name has its origin in the 1990s development of the EPRI Utility Communications Architecture, whose components were absorbed into IEC 61850 in 2000; the user group also migrated its focus to IEC 61850, and a few other IEC utility communications and integration standards. See more information at http://www.ucaiug.org/ .

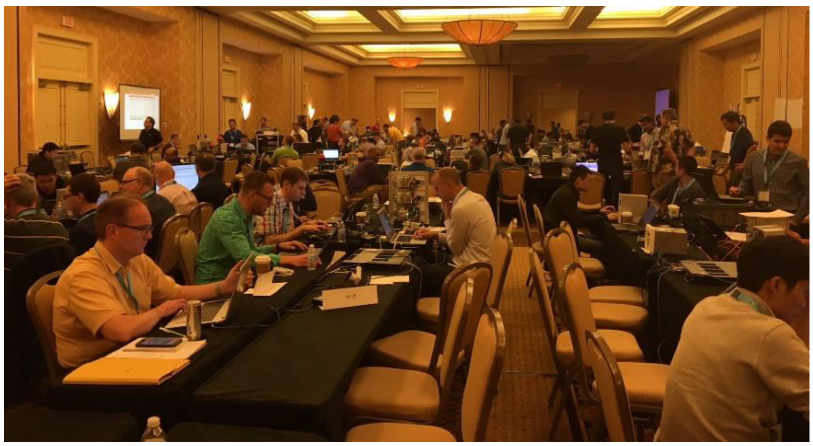


Figure A-1. IOP testing in ballroom of Marriott Convention Center, New Orleans

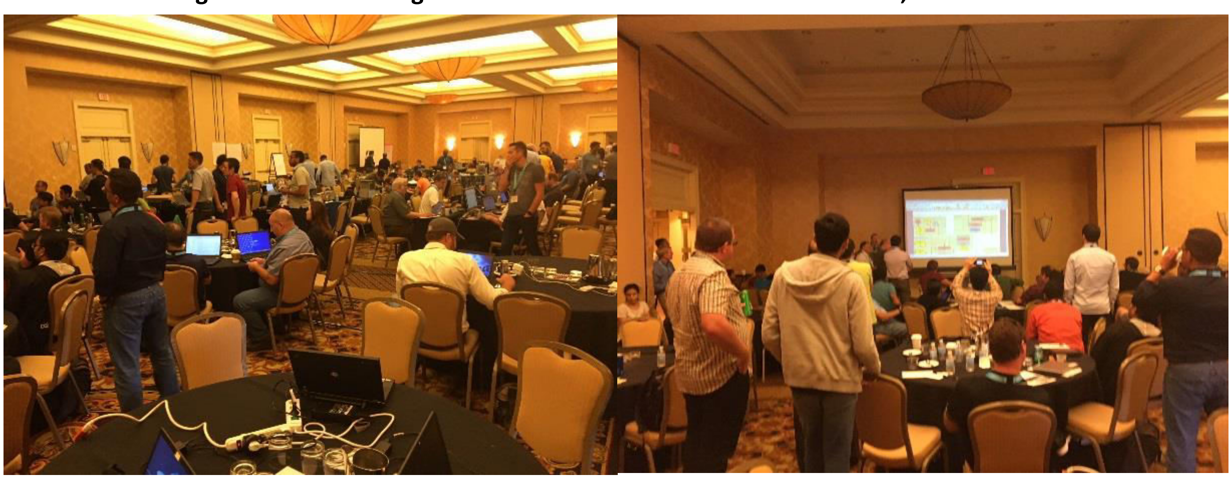


Figure A-2. Continuing testing and reviewing of progress

A.2 Test program

The services to be tested at IOP included:

1. Substation project integration trial with tools.
2. Substation Configuration Language (SCL) tool operation.
3. Precision Time Protocol (PTP) per IEEE 1588, with profiles IEC 61850-9-3 and IEEE C37.238.
4. IEC TR 61850-90-5 UDP/IP Routable GOOSE (R-GOOSE) operation.
5. Cybersecurity strategies.

A warehouse full of test information and documents is available at http://IEC 61850.ucaiug.org/2017IOP-NOrleans/IOP%20Documents/Forms/AllItems.aspx .

The tests exposed long lists of detail issues documented and available online at the test website http://IEC 61850.ucaiug.org/2017IOP-NOrleans/IOP%20Documents/Forms/AllItems.aspx. While progress was uneven or chaotic at times, the participants all made massive progress in assembling an interoperable substation application from diverse tools and equipment in a few days.

We note that the integration team comprised the world's leading experts in IEC 61850 design concepts and product development, with a limited number of utility engineers witnessing the proceedings. In the writer's opinion, massive and complex IEC 61850 standards and product development requires a persistent or continuous process like this to find and fix interoperability problems before users struggle with them.

A.3 Engineering tools

The SCL and integration test tracks merged as two engineering tool suppliers split the substation project described below, and interacted with all the vendor and product specific tools and file formats to generate a functioning application. The workflow did not have the smooth operation of a well-developed process yet, yet there are massive details that are correctly handled by the tools in their current state.

The author was focused on the operation of tools, with a special eye on GOOSE integration and documentation. The system tools have means of engineering and documenting GOOSE and MMS client-server connections. We have only begun assessment of how these documentation capabilities could serve practical projects or lifecycle maintenance in a utility environment, but seeing live what information is provided gives us a basis for further questioning and process development.

A simple freeware tool *SCLViewer* found on the UCA website (not the IOP website) by the writer during these tests helps with easy parsing of configuration data provided as .xml SCL files, which are not easily read by human interpreters. This tool is accessible only to UCA members on the website; other readers can contact the author for files and instructions.

A.4 Summary

The 2017 interoperability test demonstrated a broad offering of IEC 61850 products and engineering tools which were successfully integrated into typical system applications.

Integration required moderate levels of engineering effort, creating the appearance of advanced and maturing product development, but with some products in beta state.

Ethernet network configuration problems were the most challenging detractor from interoperability test progress. This demonstrates a focus topic for utility users of IEC 61850. Notably, it appears that pre-test network engineering project management faltered before this IOP, with infrastructure problems delaying progress in IEC 61850 application integration. This comprises a major lesson for utility users of IEC 61850.

IOP included testing for other services and capabilities which generally worked well:

- Merging units and sampled value (SV) communications per 61850-9-2 and UCA 9-2 LE, with a serious remaining ambiguity about sample timing synchronization to be resolved.
- IEC TR 61850-90-5 WAN-routable GOOSE and SV (R-GOOSE and R-SV). Both are used for wide-area synchrophasor transport as well as GOOSE for control. Authentication feature not tested.
- Time synchronization via IEEE 1588 PTP and PPS in addition to IRIG-B.
- Network security policy implementations.

Product vendors and third-party tool developers demonstrated a variety of tools which showed an advanced stage of development, apparently close to or at commercial product refinement.

Tools offered a variety of functions including IEC 61850 system configuration (GOOSE and MMS client-server association), network traffic monitoring and testing, product configuration and configuration-file format conversion, SCL file analysis or validation, and product communications simulation (multiple devices simulated within one tool).

OPAL-RT real-time power system simulator offers IEC 61850 SV and GOOSE interfaces, which have already been available from RTDS.

System configuration engineering tools (SCTs) include capabilities for:

- Building applications based on Standard-defined logical nodes (LNs) and data objects (DOs), plus user-defined logical nodes of types GGIO and GAPC.
- Building applications as a one-line diagram with primary power apparatus and instrument transformers; and creating substation configuration SSD SCL file.
- Engineering 61850 networked applications based on P&C functions and substation configuration, without P&C devices specified (top-down).
- Attaching and integrating P&C devices to an already-engineered substation application.
- Building substation applications based on pre-selected IEDs (bottom-up).
- Generating configured IED files (CID and IID) for processing by vendor tools, or direct loading into selected products with direct import capability.
- Producing various formats of project documentation, which are topics for further evaluation.

SCTs still lack:

- Multi-project managed system engineering interface (SED) file handling capabilities.
- Other project segmentation features as clear menu choices. The investigators hypothesize work-arounds.
- User logic presentation – the Standard still lacks Part 90-11 that is supposed to define how to do this. But blind generic nodes GGIO and GAPC are available for embedding user-defined logic functions.

The project investigators are focused on project engineering which includes:

- Automated IECX 61850 Part 6 compliant project engineering that includes defined LNs mixed with practical user-defined logic blocks - as contrasted with hand-mapping and documentation of GOOSE or MMS DOs. The IOP yielded strong evidence that this can be done and documented with newly-demonstrated tools.
- Means by which protection zones or project segments are safely isolated for maintenance configuration. The IOP did not produce a clear approach, and the investigation continues. SED-file project segmentation and management is not yet implemented in any tool.

IOP discussions highlighted tools for and means of viewing and documenting GOOSE connections which are convenient, and not based on hand-built Excel spreadsheets. These deserve trials in practical projects.

B. APPENDIX B – THE IEC 61850 SYSTEM CONFIGURATION PROCESS

This appendix contrasts the conventional process to configure a protection and control (P&C) system with that utilizing the methodology envisaged by the IEC 61850 standard.

B.1 Classical P&C engineering process

In order to define an IEC 61850 engineering process, the steps involved in classical P&C engineering are defined. These same steps need to be included in IEC 61850 engineering but the specifics of the process are different.

Classical P&C engineering is typically a top-down process, starting with a station layout, with details for each level specified throughout the engineering process. Documentation is mainly drawing-based. The typical conventional P&C engineering process and document types are shown in Figure B-1, while documentation specifics are given in Table B-1.

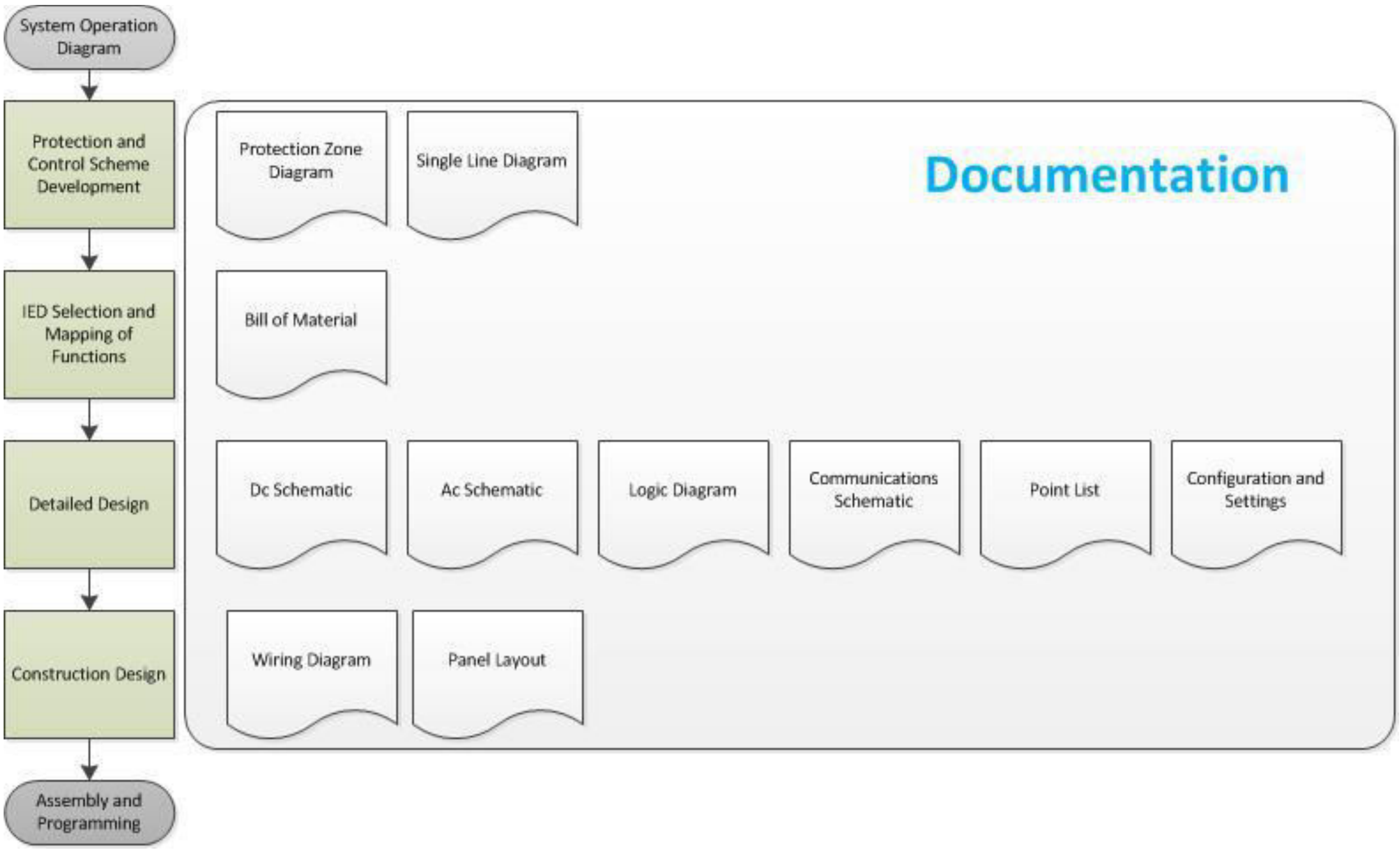


Figure B-1. Classical P&C engineering process and documentation

Table B-1. Classical P&C engineering documentation

Document	Description
System Operation Diagram	The system operation diagram is prepared by the planning group as input to P&C engineering. The System Operation Diagram typically shows: • Power system components • Voltage level • Circuit breakers, switches • CT location, CT polarity, PT locations There is no industry standard on what needs to be shown in System Operation Diagram and information will vary from utility to utility.
Single Line Diagram	The single line diagram provides the schematic design of protection and control, based on the input from the System Operation Diagram. Many utilities document the protection and control scheme in the single line diagram with scheme logic. Other utilities document scheme logic separately as part of the P&C documentation package.
Ac Schematic	The ac schematic shows the system with all three phases (Three-Line Diagram) and provides the detailed connection paths of the IED ac measuring circuits including: • Terminal numbers • Test switches • CT and PT ratios • CT polarity/star point location • CT taps
Dc Schematic	Traditionally, the dc schematic showed the complete protection and control scheme, including logic. This changed with the use of numerical relays where the available inputs and outputs (I/O) are shown as graphics and/or in a table.
Logic Diagram	Logic diagrams describe customized logic and scheme logic configured in numerical relays and IEDs. The logic diagrams may also include portions of the manufacturer's fixed logic, for better understanding of the scheme in testing. The logic diagram typically shows all input information, relay and scheme logic, and outputs.
Communications Schematic	The communications schematic shows: • Physical network and device diagram (routers, switches, network connections, gateways, and other networking components) • Functional data flows • Protocols (DNP3, IEC 61850, etc.) • Time synchronization equipment and protocol. • Cybersecurity design with physical and electronic security perimeters, firewalls, gateways, and isolation zones or DMZs. • Communications media (copper, fiber, microwave, etc.). • Communications circuit identification by type.
Miscellaneous P&C documentation	Configuration of numerical relays typically also includes assignments of labels, LEDs, targets and other customized HMI elements. Additionally, SCADA point lists and communications settings may need to be entered in the relays. Generally, these are based on standard templates, with application-specific customization for each zone or IED.

B.2 IEC 61850 P&C engineering process

The IEC 61850 engineering process envisions and supports a top-down engineering process as illustrated in Figure B-2. However, most utilities are still using a bottom-up engineering approach for the IEC 61850 configuration with the system specification and engineering done in the traditional way, since many implementations use conventional wired solution in parallel to IEC 61850 services.

There is a substantial effort involved in IEC 61850 project engineering when starting from scratch without a standard design, as is generally the case for a trial or pilot project. However, it should be recognized that today's P&C engineering is largely based on templates and protection scheme standards. IEC 61850 projects will also benefit from standard designs and templates when they have been established.

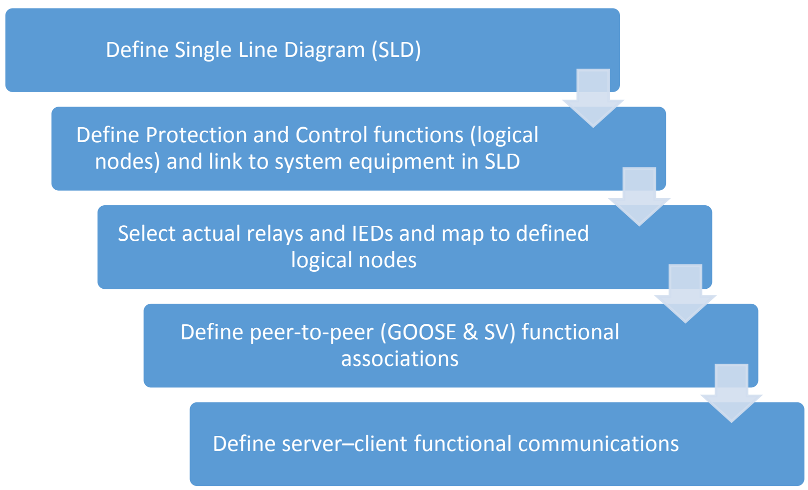


Figure B-2. IEC 61850 top-down engineering process

The user should be able to employ in sequence the system specification tool, the system configuration tool, and the IED configuration tool to design and engineer an IEC 61850 based protection and control system. Each of the different tools is used in a different phase of the project and is used for a specific design and engineering step. Table B-2 describes the different tasks performed by the different tools.

Table B-2. Overview of IEC 61850 engineering tools

Tool Domain	Functionality
System Specification Tool	In the project requirement phase, a System Specification Tool allows user to describe elements of the application as a single-line diagram, with application names and the required functions to be performed. This formal description can be used for evaluation of capabilities of alternative products, as well as serving as an input to a system configuration tool in the system design phase. The tool output specification includes standardized IEC 61850 functions (logical nodes or LNs) and their defined I/O signals (data objects), as well as user-defined LNs.

Tool Domain	Functionality
System Configuration Tool	The System Configuration Tool assigns the above-configured protection and control functions to actual IEDs. The input comprises the required functions and associated data flows defined during the system specification phase above. In this second step the communication connections between the IEDs are configured by the system configuration tool, so that the intended system functionality is implemented.
IED Configuration Tool	The IED Configuration Tool uses the output of the system configuration tool to create actual IED parameters and settings for each specific selected IED. This tool or toolset is usually manufacturer-specific, or even specific to an IED type.

Most IEC 61850 systems today are engineered using the bottom-up approach. This is based on familiarity, along with the fact that reliable manufacturer-independent system specification tools were not available in the past. Utilities must understand and slowly adjust to the new top-down engineering approach, which dramatically changes long-standing practices. Therefore the system specification is still generally performed in the traditional way and documented in drawings and legacy file types.

IEC 61850 P&C Engineering Documentation

The documents produced in the IEC 61850 P&C engineering process are similar to those for classic P&C engineering, as illustrated in Figure B-3. The abbreviations SSD and SCD refer to specific IEC 61850 System Configuration Language (SCL) XML file types explained below.

IEC 61850 Engineering Tools and Workflow

Figure B-4 shows the workflow for IEC 61850 configuration, which involves five distinct steps (Table B-3).

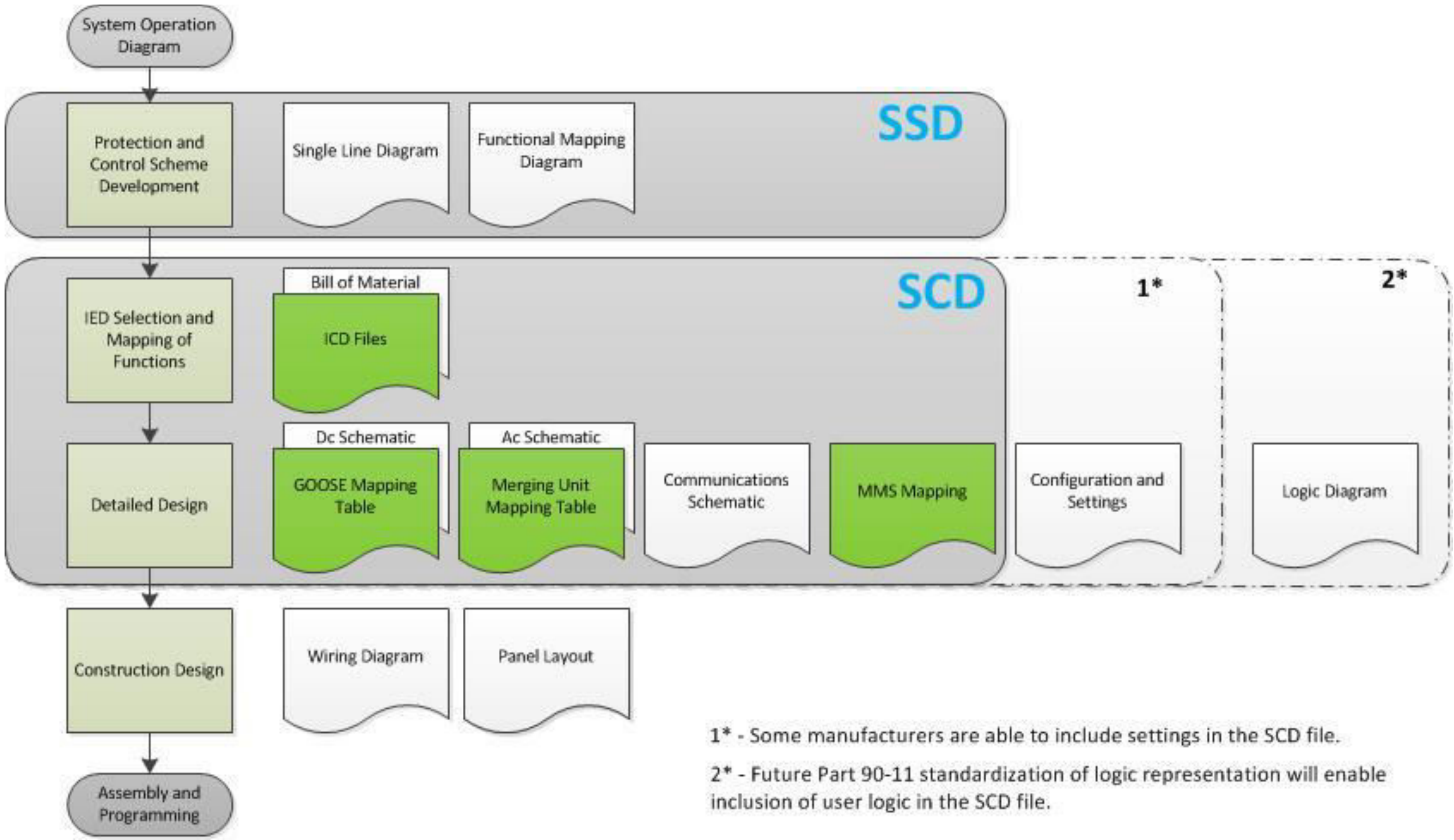


Figure B-3. IEC 61850 Engineering Documentation

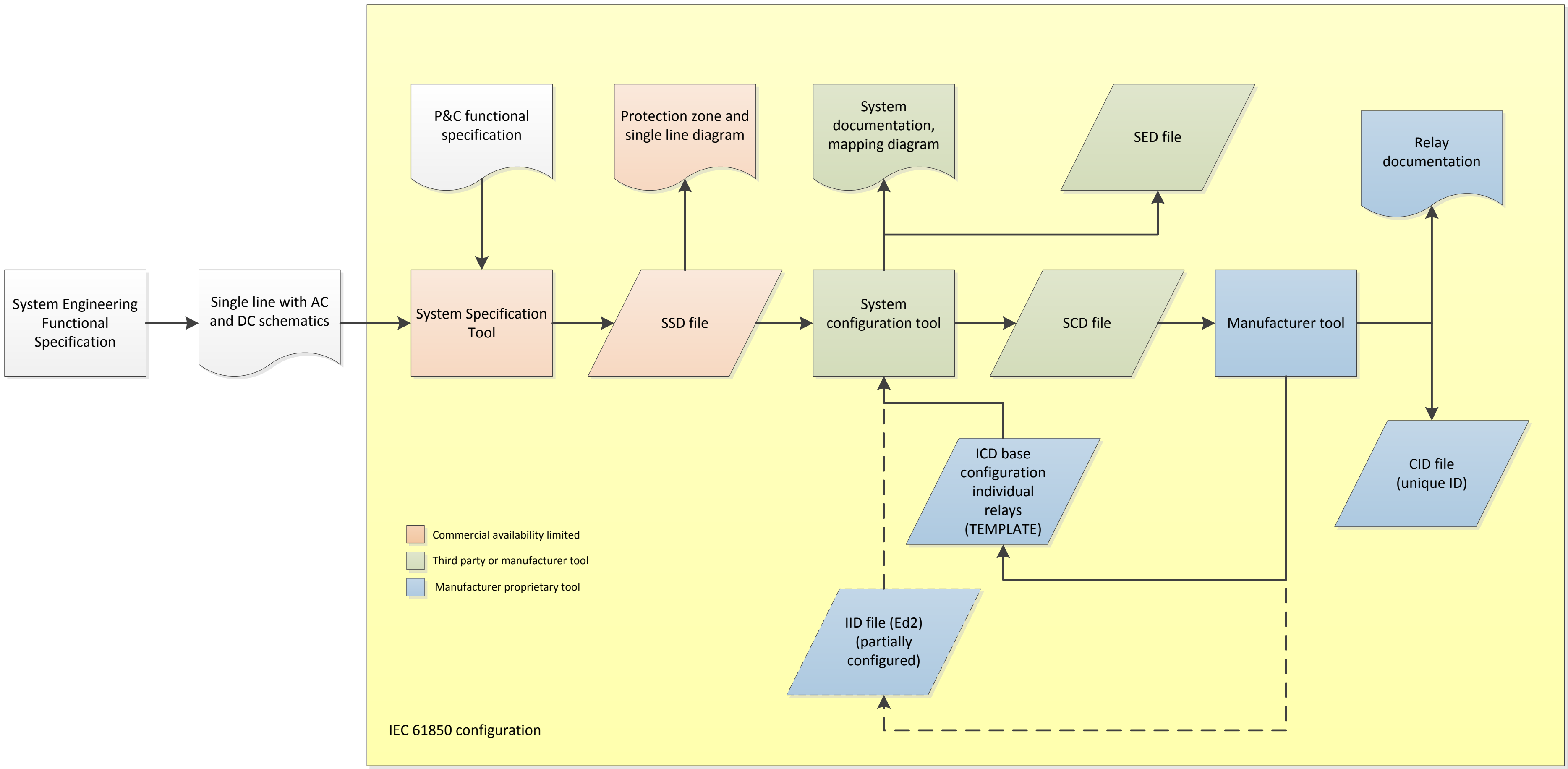


Figure B-4. IEC 61850 configuration process

Table B-3. Overview of IEC 61850 engineering workflow

Step	Description
0	The starting input for the IEC 61850 engineering process is the system engineering functional specification. In Figure B-4, a third-party system specification tool capability described in Part 6 takes user input of the single-line diagram and the functions to be applied in the substation to create a System Specification Description (SSD) file in XML format. Since tools with this one-line/function entry capability are just emerging, users have been entering manual configuration information directly into the system configuration tool along with product vendor-provided ICD information described next.
1	A set of manufacturer-specific tools include for each IED an IED Capability Description (ICD) file in XML format, with semantics and syntax as defined by IEC 61850 Part 6. Each ICD file describes the total communications and application model support capabilities of the IED, which the engineering process will configure for the IED's specific role. The system configuration tool requires an ICD file for each IED to be used in the IEC 61850-based communications system.
2	A third-party system configuration tool imports ICD files for all IEDs that are involved in the substation protection and control system communications. The IEDs can be senders (servers), receivers (clients), publishers, subscribers, or all of these. The tasks of the system configuration tool include: • Assigning addresses for all IEDs • Programming the dataflow directly among IEDs (GOOSE connections) • Programming dataflow between IEDs and primary equipment (process bus connections) • Creating lists of data objects for client systems (such as HMI and SCADA concentrator) The system configuration tool uses the SSD file, or direct input of the user's application intentions, to develop these configurations. The resulting system configuration with communications data connections is compiled in a Substation Configuration Description (SCD) file in XML format as defined in IEC 61850-6.
3	The SCD-defined data connections need to be applied as updated configurations of the individual IEDs. The manufacturers' proprietary tools read the SCD files and extract relevant information to configure each IED. The output from each manufacturer's tool is one or multiple Configured IED Description (CID) files - XML files produced for each IED separately. Each manufacturer's tool also must convert the contents of each CID file to a setting file in the product vendor's proprietary format, since there are only a few IEDs on the market that can accept CID files directly as setting files. The SCD file is also the input for the configuration tools of client systems (HMI, SCADA/enterprise servers, historian), listing all logical functions and data objects available by network communications.
4	Documentation of system configuration is to be produced by the system configuration tool. Separately, vendor tools document the IED configuration.

B.2.1 Summary of IEC 61850 Part 4 and Part 6

IEC 61850-4 covers system and project management. IEC 61850-6 covers configuration description language (SCL) for communication in electrical substations related to IEDs. This section provides a high level summary of these standards with regard to how they are related to the system configuration process.

IEC 61850-4: System and project management

For purpose of this document, the engineering process described in Part 4 is of interest.

Part 6 defines actor roles in the engineering process as follows (numerals are text quoted from the standard; italicized sub-items are authors' comments):

5. The project requirement engineer sets up the scope of the project, its boundaries, interfaces, functions and special requirements ranging from needed environmental conditions, reliability and availability requirements up to process related naming and eventual specific address range restrictions or product usage. They define what they want to have application wise and how they wants to operate the system (project requirement specification). They finally accept the delivered system.

   This role would correspond to the System Engineering Functional Specification in Step 0 in the preceding section.
6. The project design engineer defines, based on the requirements specification, how the system shall look like; its architecture, requirements on the products needed to fulfil the required functions, how the products should work together. They thus define the system design specification.

   This role would correspond to Step 1, where the P&C design engineer uses a System Specification Tool to create an SSD (System Specification Description) file.
7. The manufacturer supplies the products from which the system is built. If necessary, they supply a project specific IED configuration.

   This role would correspond to the supply of ICD (IED Capability Description) files (or IID files – Instantiated IED Description) in Step 1.
8. The system integrator builds the system, engineers the interoperation between its components based on the system design specification and the concretely available products from the manufacturers, and integrates the products into a running system. This results in a system configuration description.

   This role corresponds to using the System Configuration Tool to create an SCD (System Configuration Description) file in Step 2.
9. The IED parameterizing engineer uses the set-up possibilities of the system and device configuration to adjust the process, functional and system parameters of an IED to the project-specific characteristics.

   This role corresponds to importing the SCD file in the manufacturer IED configuration tool in Step 3.
10. The testing and commissioning engineer tests the system on the basis of the system configuration description, system design and requirements specification and additional documentation, and puts the system into operation.

    This role would correspond to creating system configuration documentation and IED documentation in Step 4.

<u>IEC 61850-6: Configuration description language for communication in electrical substations related to IEDs</u>

This part of the standard specifies a description language for the configuration of electrical substation IEDs; Substation Configuration description Language (SCL).

The standard first provides an overview of the different file types used in the engineering of an IEC 61850 substation automation system, and then gives a detailed specification of the datasets and naming conventions for these files. It would be expected that the system configuration tool creates the required files and that a user will only work on a higher level, defining the LNs, communications, and the physical devices in the system.

Table B-4 gives an overview of the tools that create the various files and the dataflow between the tools. Part 6 describes these in detail. The files are tabulated below:

Table B-4. IEC 61850-6 SCL File Types

File	Description
IED Capability Description (ICD) file	It defines complete capability of an IED. This file needs to be supplied by each manufacturer to make the complete system configuration. The file contains a single IED section, an optional communication section and an optional substation part which denotes the physical entities corresponding to the IED.
System Specification Description (SSD) file	This file contains complete specification of a substation automation system including single line diagram for the substation and its functionalities (logical nodes). This will have Substation part, Data type templates and logical node type definitions but need not have IED section. IEC 61850-6 provides a formal means to define the single line diagram with customer's functional names and the intended automation system functionality at the primary equipment identified in the single line description (SSD, system specification description). Commercial products for creating SSD files are presently limited. The system configuration tools typically include defining a single line diagram and theoretically could create an SSD file as an output, but this functionality is not provided. Many of them have the ability to import SSD files so it would be beneficial to have this functionality in the future so that SSD files could be exchanged between different system configuration tools.
Substation Configuration Description (SCD) file	This is the file describing complete substation detail. It contains substation, communication, IED and Data type template sections. An .SSD file and different .ICD files contribute in making an SCD file.
Configured IED Description (CID) file:	It is a file used to have communication between an IED configuration tool to an IED. It can be considered as an SCD file stripped down to what the concerned IED need to know and contains a mandatory communication section of the addressed IED.
Instantiated IED Description (IID) file:	It defines the configuration of one IED for a project and is used as data exchange format from the IED configurator to the system configurator. This file contains only the data for the IED being configured: one IED section, the communication section with the IED's communication parameters, the IED's data type templates, and, optionally, a substation section with the binding of functions (LNodes) to the single line diagram.
System Exchange Description (SED) file	This file is to be exchanged between system configurators of different projects. It describes the interfaces of one project to be used by another project, and at re-import the additionally engineered interface connections between the projects. It is a subset of an SCD file with additional engineering rights for each IED as well as the ownership (project) of SCL data.

The last two file types (IID and SED) were introduced with Edition 2. While the tools are expected to handle the creation of these files, the user still needs to have substantial knowledge of the IEC 61850 standard. In order to define the required functionality, the user needs to be familiar with Logical Node names, and names for parameters and values to be communicated via GOOSE and MMS from these Logical Nodes. Logical Nodes are defined in IEC 61850-7-4.

C. APPENDIX C – OPENFMB PRIMER

OpenFMB differs from legacy protocols such as DNP3, MODBUS, and even IEC 61850 in a number of ways and represents a novel way of enabling interoperability of field devices. By means of introduction, this section provides background on the framework and then explains considerations going forward.

C.1 Introduction to OpenFMB

Open Field Message Bus (OpenFMB) represents one of the Smart Grid Interoperability Panel's (SGIP) EnergyIoT initiatives that attempts to bring Internet of Things (IoT) and interoperability to the power systems. It was specifically intended for application to field devices and field level computing (sometimes referred to as *fog computing* as the corollary to cloud computing). The stakeholder group describe OpenFMB as:

> *Open Field Message Bus (OpenFMB) is a framework and reference architecture comprised of existing standards that enables grid edge interoperability and distributed intelligence, augments operational systems, and enhances integration with field devices.*

The frameworks subscribe to a number of guiding principles, which include:

- Based on operational and functional requirements
- Flexible architecture
- No reinventing the wheel
- Focus on business value and objectives
- Collaborate with standards bodies
- No stranded resources
- Security built-in from the beginning

Figure C-1 presents the vision for the evolution of grid communication, essentially precipitated by the accelerated integration of grid-edge devices, most notably distributed energy resources (DER). As shown, legacy hub-and-spoke architectures require that all data flows must pass by way of the back office servers, ultimately leading to data congestion, and unnecessary configuration of multiple links. By enabling peer-to-peer communication in the field, traffic can be customized to the needs of the use case, only implicating the actors and data points minimally required to deliver the functionality.

Figure C-2 provides an illustration of the various layers of OpenFMB that make this possible. Peer-to-peer middleware forms the transport layer, which is compatible with multiple physical media (WiFi, cellular, BPL, Fiberoptics). The OpenFMB data model underpins the interface layer and interacts with the transport layer and higher level functions. Finally, the management services layer provides higher level functions that support monitoring of a given application and its evolution over time.

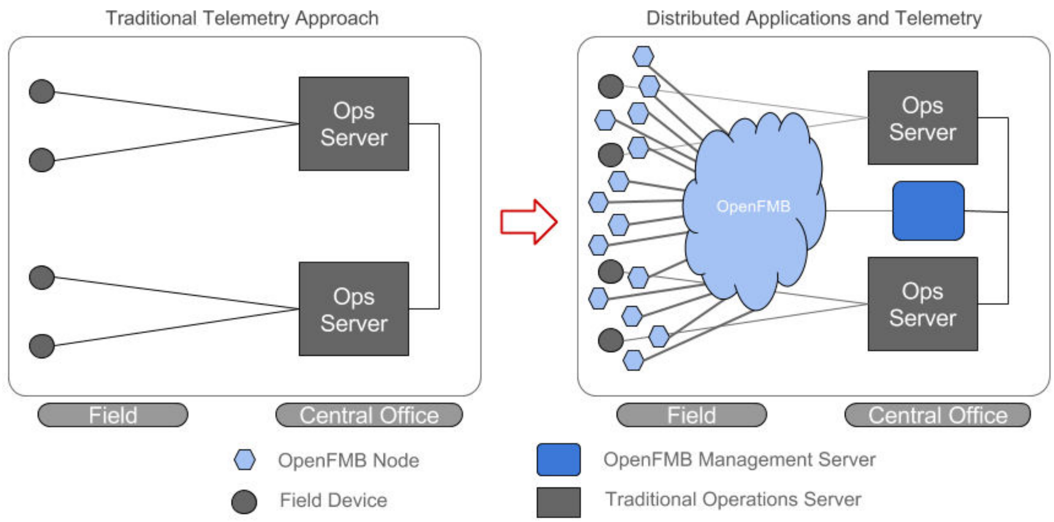


Figure C-1. Evolution from present data communication with field devices towards OpenFMB [12]

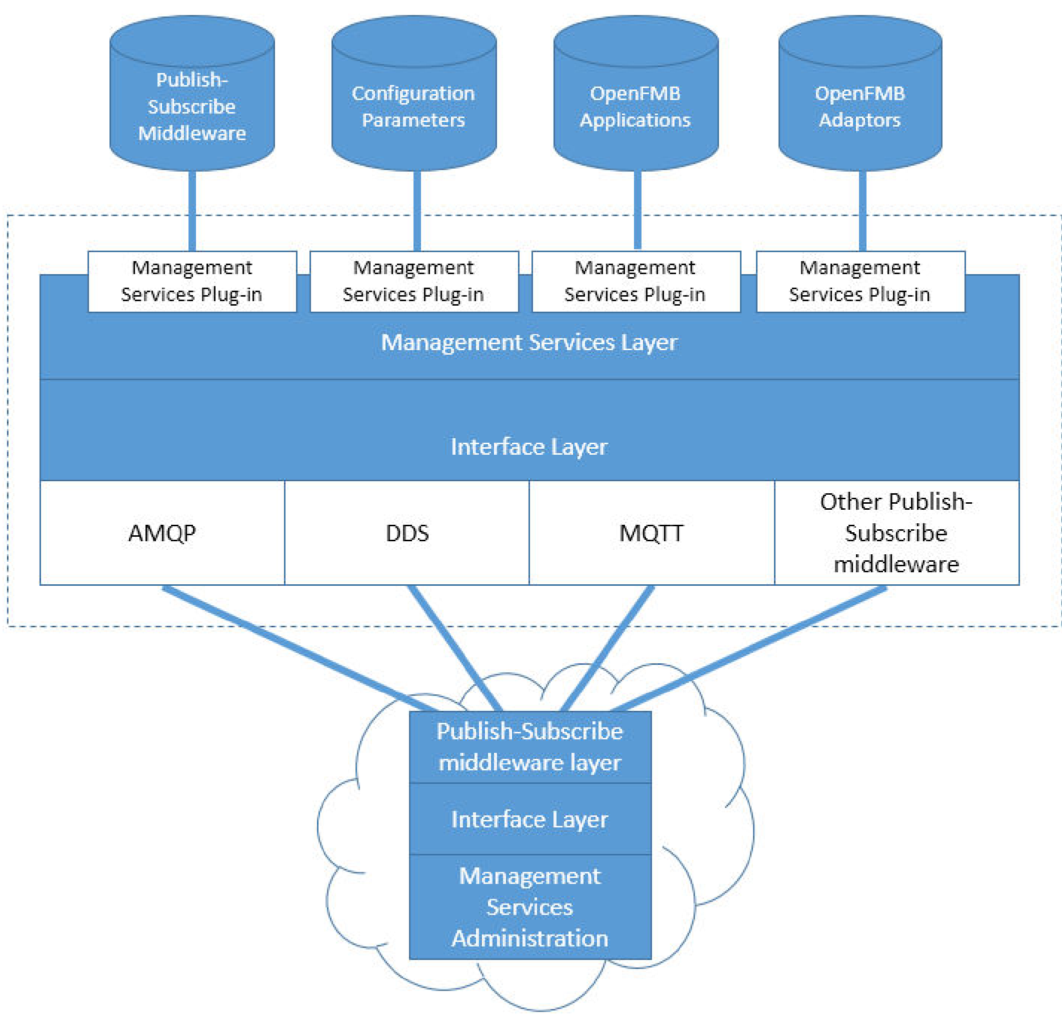


Figure C-2. Graphical representation of the OpenFMB framework

Similarly to IEC 61850, the underlying data model is one of the key features that supports interoperability and scalability. A common representation of typical devices and applications ensures that disparate manufacturers conform to agreed-upon semantics, greatly reducing the time to configure and test a given interface. In addition to other packet information related to the publish-subscribe process, these data models are passed as XML payloads over the middleware. This standard, hierarchical structure greatly reduces the time for configuration of systems and development of new applications.

Figure C-3 presents a unified modeling language (UML) representation of the data model for a battery energy storage system (BESS). This includes multiple attributes that describe the system characteristics, time stamp information for the payload, and variables related to its operation.

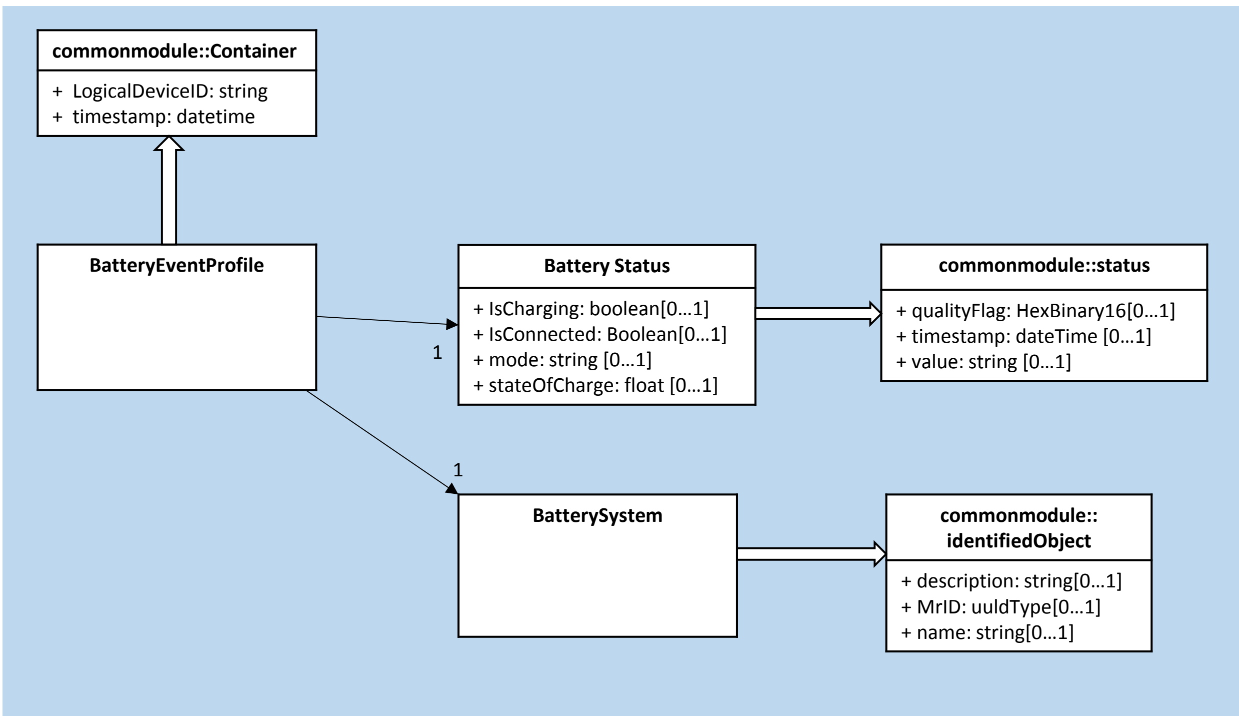


Figure C-3. Unified Modeling Language (UML) representation of OpenFMB data model for BESS

C.2 Advantages

The OpenFMB framework presents a number of advantages to the industry, particular in light of the development of IoT applications in the power sector and in related fields. As it utilizes internet protocol (IP) based technologies, it enables higher-level functions not possible in legacy protocols, and the fact that it is based on an open-standards approach, the risk of vendor lock-in is greatly reduced, as specific implementation must be vetted by the wider community, avoiding proprietary interpretations.

Specifically, the key advantages are summarized as follows:

- Ratified (NAESB) standard providing a common semantic language for field device integration.
- Highly scalable compared to legacy protocols due to pub-sub nature of bus architecture, common transport layer and unified information model.

- Enables peer-to-peer integration using IoT technology, breaking out from traditional hub-and-spoke architectures. This makes the framework highly amenable to the architectures studied in the SODA project and distributed of various levels of aggregation out to the substation and the field.
- No implicit binding to underlying transport layer, allowing appropriate technologies to be used for specific use cases.
- Information model based on best-of-breed harmonization of CIM and 61850. The information model will continue to evolve as these two groups address the gap in the information model and as new applications are developed.
- Common information models are easily extendable to add extra data, while maintaining backwards compatibility with nodes that don't know about the additional data. E.g., If wind speed information is added to generator measurement data, nodes that don't know about wind speed can still understand the real power measurement.

C.3 Implementation and adoption challenges

While OpenFMB possesses many promising attributes, challenges persist, in part due to the significant change that it represents to distribution operations and communication. The framework has been pushed by a few of the larger progressive utilities, led primarily by Duke Energy and the *Coalition of Willing*, a group of vendors committed to piloting these technologies. However, until greater traction can be achieved—which will likely involve a combination of market push and continued proliferation of grid-edge assets—challenges for widespread implementation will likely continue.

The most common challenges are the following:

- Limited uptake by the industry at this stage. This is probably the greatest stumbling block and in a conservative industry, these things generally take time and require vetting and experimentation through such mechanisms as EPIC or other state and federal level funding. This is countered somewhat by a relatively strong community and support through the SGIP.
- Current information model has limited device support. While many of the grid-edge assets are covered, novel devices such as the RAMCO and the Grid Co device needed to be forced into similar type data models. This should improve through greater adoption and pilots but remains a challenge for the short-term.
- Most field devices do not yet explicitly support OpenFMB out-of-the-box. This fact results directly from adoption and mirrors the support of IEC 61850 in the early days of its implementation.
- Protocol translation to legacy protocols still required at the edge. Following on from the previous point, the only way to enable an OpenFMB node from a non-compliant device is through installation of an additional translator at the remote terminal unit (RTU).
- Some publish-subscribe protocols require a broker, meaning they're not truly peer to peer (e.g., MQTT). Middleware based around DDS avoid the use of a broker and hence avoid single points of failure and reduce latency.
- Migration from legacy architectures will likely have some challenges. As with the integration of DER and the struggles associated with the paradigm shift to distributed production of energy, the shift towards distributed control architecture will be met with similar technology and organizational issues. The best approach revolves around establishing a roadmap with input from relevant stakeholders, well defined use cases, considering possible future use cases, and how implementation of OpenFMB can drive value for the utility and other organizations.

D. APPENDIX D – ADDITIONAL USE CASE RESULTS

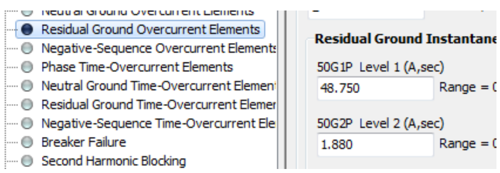
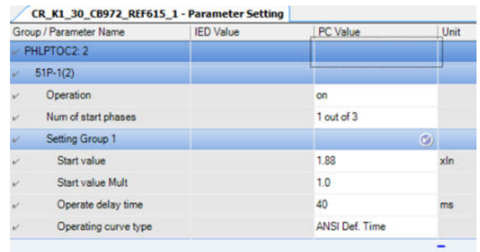
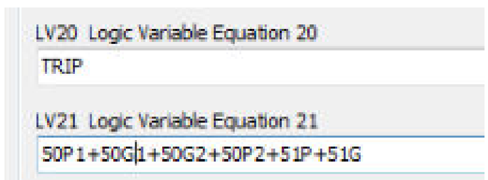
Use cases 1, 2, 4, 5, 6, 7, 8 and 9 consisted of multiple test cases. The earlier use case sections only detailed a representative sub-section of these test cases for the sake of brevity. The sections that follow document the results of those test cases that were omitted from the earlier sections.

D.1 Use Case 1: Lifecycle asset provision and integration

D.1.1 Test Case 1: Integrate new IED into existing system

In this section, the detailed steps required to properly add a new IED (from two different vendors) to an existing IED from the system are documented using a short description and the related screen shots for evidence.

Step 1: Configure new IED, functions and settings

<table>
<tr><th>Description</th><th>Vendor 1</th><th>Vendor 2</th></tr>
<tr><td>Configure protection settings</td><td>
</td><td></td></tr>
<tr><td>Connect variables with functions</td><td>

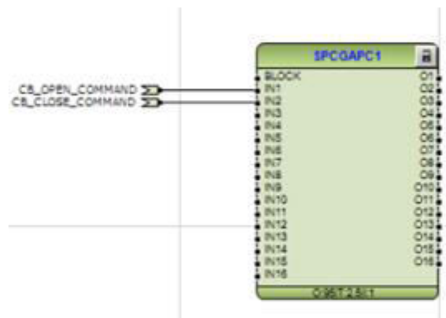
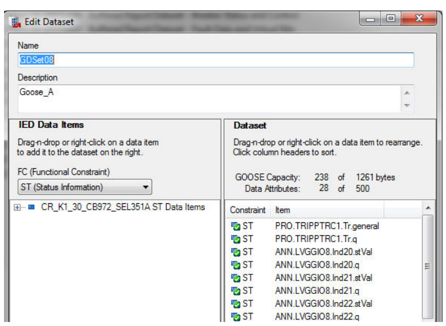
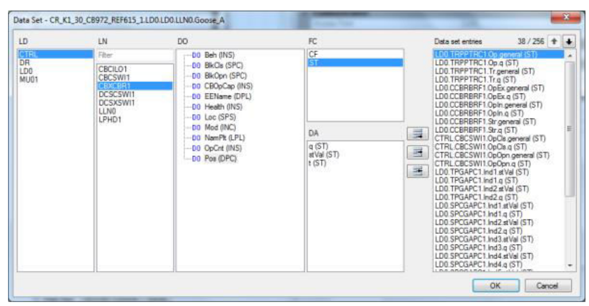
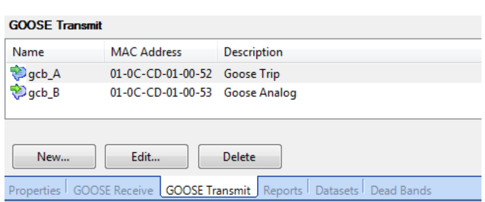
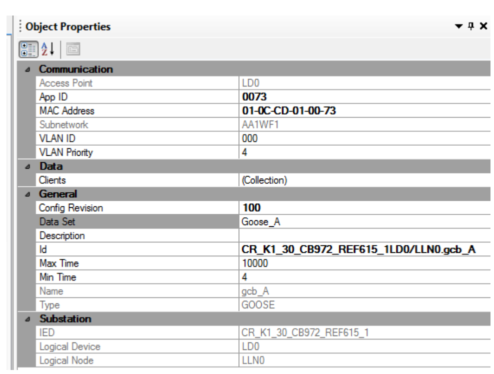
Note: Variables are used as interface to a function. Later the variables are connected with the relevant GOOSE message</td><td></td></tr>
<tr><td>Configure data sets</td><td></td><td></td></tr>
<tr><td>Configure GOOSE control blocks</td><td>
</td><td></td></tr>
</table>

Figure D-1. Step 1: Configure new IED, functions and settings

Step 2: Export and Import ICD/CID file of the new IED device

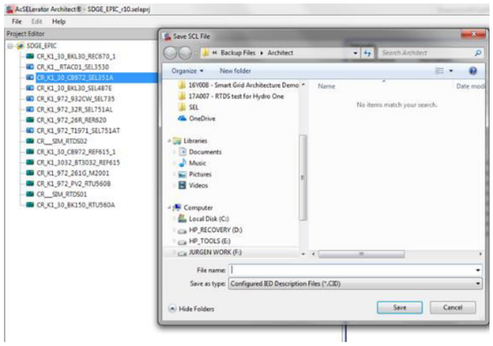
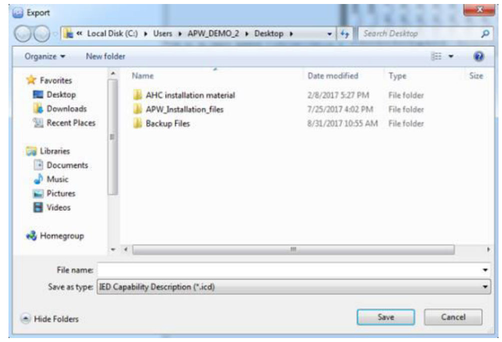
Description	Vendor 1	Vendor 2
Export: The IEC 61850 configuration, including GOOSE message assignments are store and distributed in form of CID or IED files	 In case of Vendor 1 devices a CID file is created as input for the system engineering task.	 In case of the Vendor 2 devices an ICD or SCD file is created as input for the system engineering task. In the given set-up there was no need to export the ICD/SCD file as the IEC 61850 system engineering function inside the Vendor 2's configuration tool was used.

Figure D-2. Step 2: Export and Import ICD/CID file of the new IED device

The users do not have to deal with the XML format of the different SCL files such as the mentioned ICD or CID File. Rather the IED and system engineering tools handle the details and provide the engineers a user friendly interface for the different engineering and configuration activities. Nevertheless if one needs to look at an SCL file any browser can be used to look up the details. An example of the XML format is shown in Figure D-3.

ied.CID - Notepad

File Edit Format View Help


```
<?xml version="1.0" encoding="UTF-8"?>
<SCL xmlns:esel="http://www.selinc.com/2006/61850" xmlns="http://www.iec.ch/618
  <Header id="SDGE_EPIC" version="72" revision="1.0" toolID="2.2.16.0" nameStru
    <History>
      <Hitem version="72" revision="1.0" when="09/05/2017 12:46:42" who="QUANTA
    </History>
  </Header>
  <Communication>
    <SubNetwork name="W01">
      <ConnectedAP iedName="CR_K1_30_CB972_SEL351A" apName="S1">
        <Address>
          <P type="IP">10.212.235.83</P>
          <P type="IP-SUBNET">255.255.0.0</P>
          <P type="IP-GATEWAY">10.212.235.1</P>
          <P type="OSI-TSEL">0001</P>
          <P type="OSI-PSEL">00000001</P>
          <P type="OSI-SSEL">0001</P>
        </Address>
        <GSE ldInst="CFG" cbName="gcb_A">
          <Address>
            <P type="MAC-Address">01-0C-CD-01-00-52</P>
            <P type="APPID">0052</P>
            <P type="VLAN-PRIORITY">4</P>
            <P type="VLAN-ID">000</P>
          </Address>
          <MinTime unit="s" multiplier="m">4</MinTime>
          <MaxTime unit="s" multiplier="m">10000</MaxTime>
        </GSE>
        <GSE ldInst="CFG" cbName="gcb_B">
          <Address>
            <P type="MAC-Address">01-0C-CD-01-00-53</P>
            <P type="APPID">0053</P>
            <P type="VLAN-PRIORITY">4</P>
            <P type="VLAN-ID">000</P>
          </Address>
          <MinTime unit="s">4</MinTime>
          <MaxTime unit="s">10000</MaxTime>
        </GSE>
      </ConnectedAP>
    </SubNetwork>
  </Communication>
  <IED desc="Relay firmware R516 modifications and conformance enhancements" na
    <Private type="SEL_IedInfo">
      <esel:ModelNumber>SEL-351-5</esel:ModelNumber>
      <esel:ModelNumber>SEL-351-6</esel:ModelNumber>
```


Figure D-3. Example XML format of a CID file

Step 3: Engineer data flow

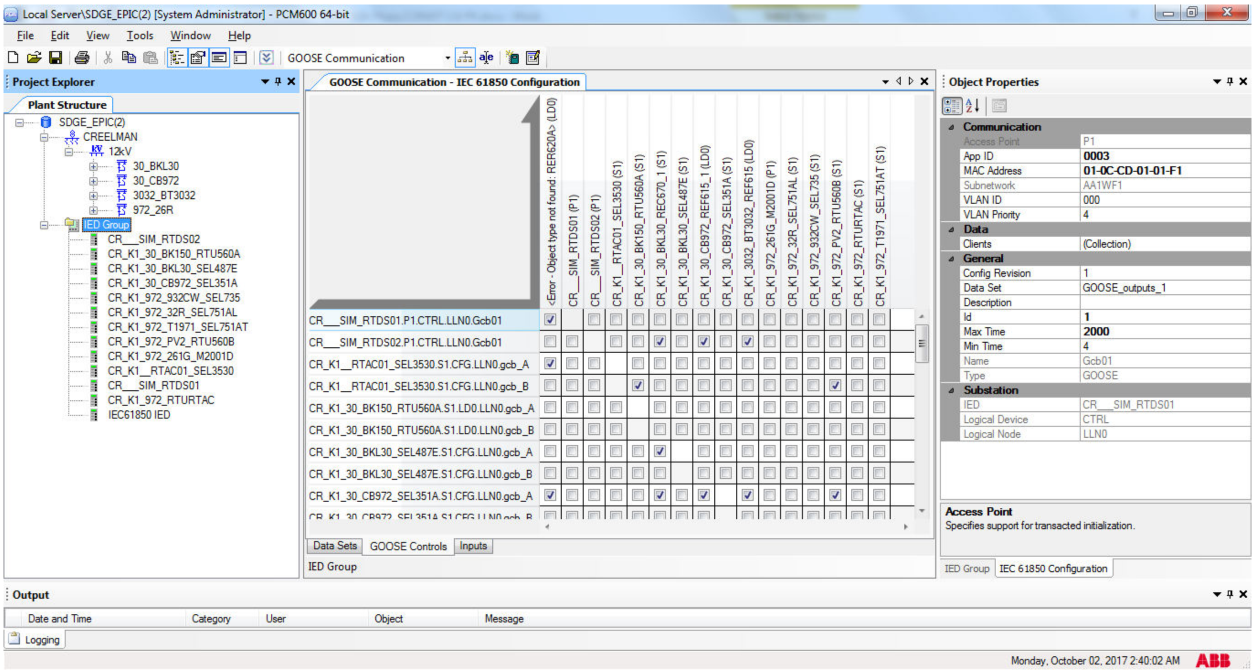
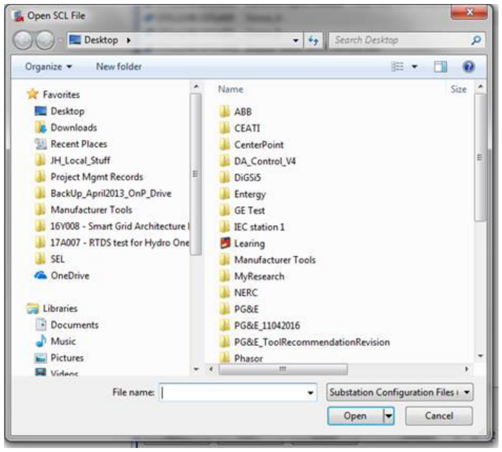
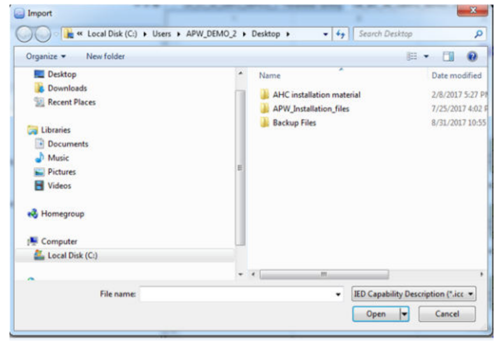
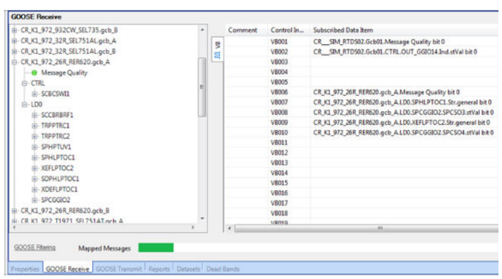
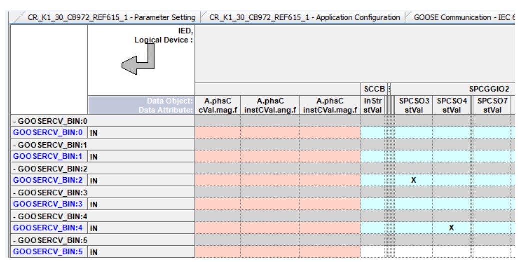
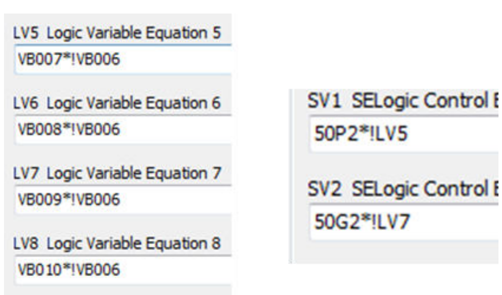


Figure D-4. Step 3: Engineer data flow

Step 4: Import SCD and connect input section

<table>
<tr><th>Description</th><th>Vendor 1</th><th>Vendor 2</th></tr>
<tr><td>Import: Importing the ICD, CID file makes it possible for any manufacturer to understand the IED capabilities</td><td>
</td><td>
</td></tr>
<tr><td>and configure the signals to internal connection points</td><td>

Vendor 1 uses VBxxx for binary input signals</td><td></td></tr>
<tr><td>Connect to internal logic</td><td>

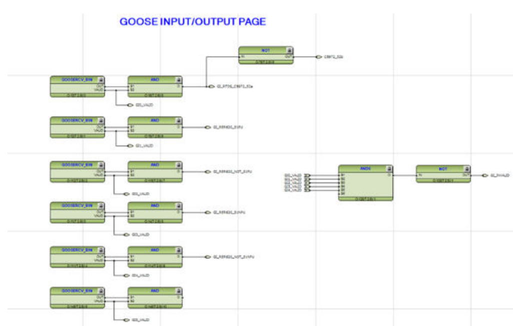
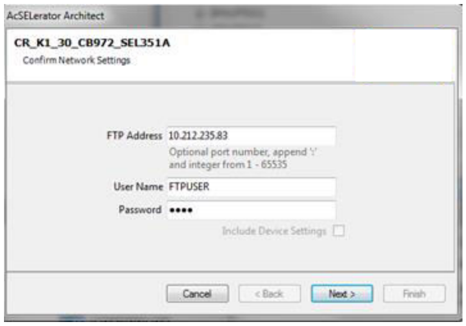
VBxxx are connected to internal logic</td><td>
</td></tr>
</table>

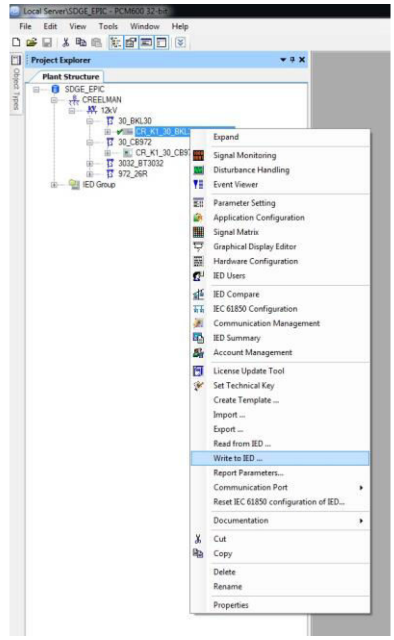
Figure D-5. Step 4: Import SCD and connect input section

Step 5: Upload SCD/CID to new IED and GOOSE subscribers

<table>
<tr><th>Description</th><th>Vendor 1</th><th>Vendor 2</th></tr>
<tr>
<td>Upload new configuration file (including communication section) to IED</td>
<td>



Vendor 1 uses two different tools to manage settings (QuickSet) and Communication configuration (Architecture)
</td>
<td>



Settings and Communication configuration is managed in one tool (Vendor 2's configuration tool) and transmitted to the relay together
</td>
</tr>
</table>

Figure D-6. Step 5: Upload SCD/CID to new IED and GOOSE subscribers

Step 6: Basic test of communication

Taking the full advantage of IEC 61850 data modeling and documenting the communication related information (communication section) as part of the SCD file is a pre-condition to enable the automatic check functionality using an IEC 61850 testing tool. After downloading the new configuration to the IEDs scan and comparison with the original SCD files provides a fast and reliable way to confirm correct configuration.

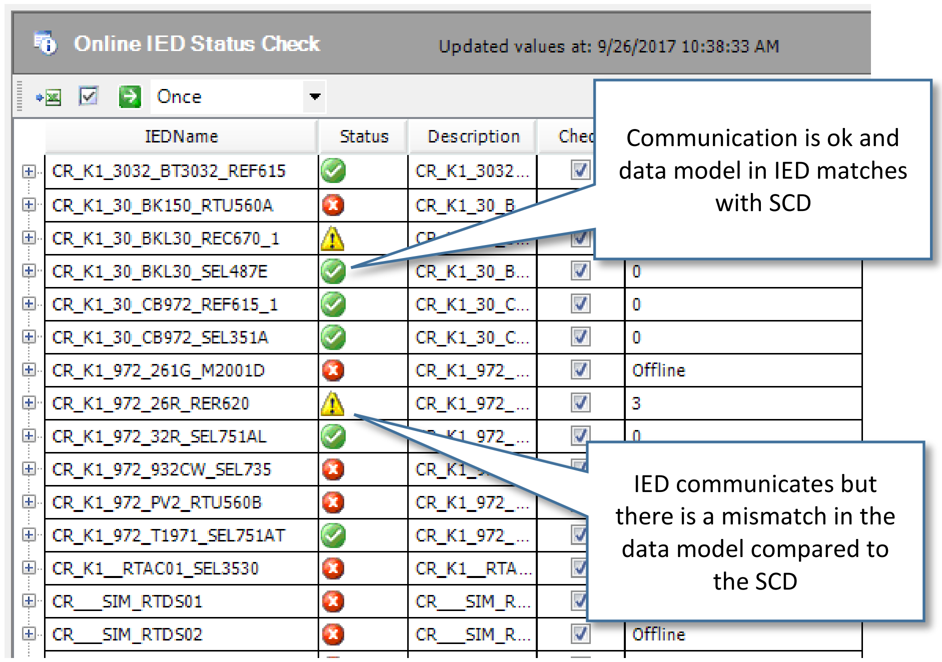


Figure D-7. Using IEC 61850 tool to check basic communication and data model consistency

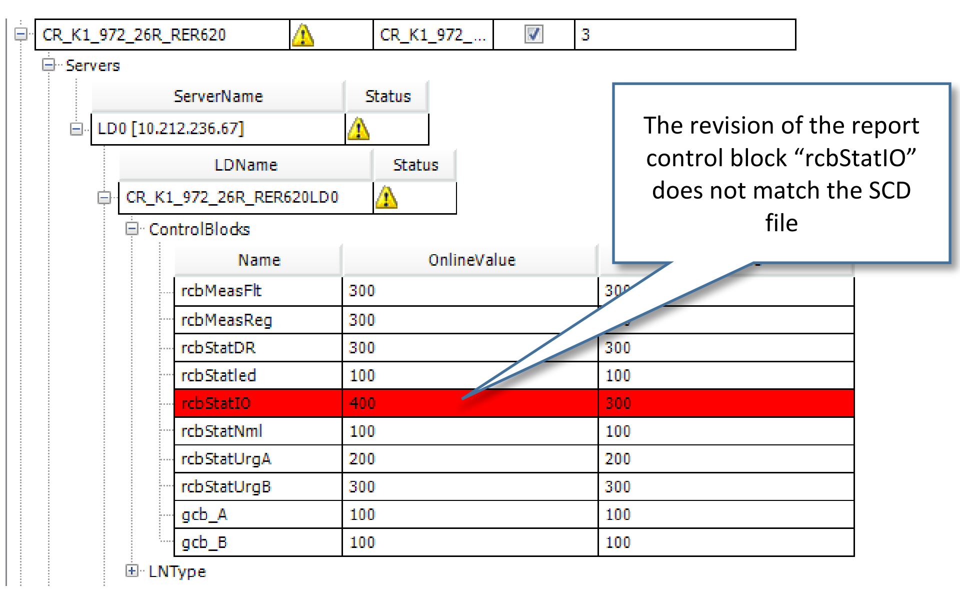


Figure D-8. Detected revision mismatch in a report control block between SCD and real IED

D.1.2 Test Case 2: Remove existing IED from system

In this section the detailed steps required to properly remove an existing IED from the system are documented using a short description and the related screen shots for evidence. The SEL-351 IED had been chosen as target IED for removal.

Step 1: Check impact of the target IED to related devices

In order to confirm the impact of related IEDs and functions before removing an existing IED following checks can be done to identify the IEDs requiring an update after removing a defined IED.

A) Check the GOOSE table document: As part of the system documentation a comprehensive table with all devices and GOOSE messages has been developed showing not only the GOOSE communication between the different devices but also the link of the GOOSE message to the internal logic of variable inside the IED.

B) Check the GOOSE matrix in IEC 61850 system engineering tool: The has also been used as system engineering tool for the IEC 61850 portion. A GOOSE matrix provides an overview on all engineered GOOSE communications across the project and allows to quickly identify IED dependencies. Figure D-9 shows a section of the GOOSE matrix of the project. Each cross in the table means there is a connection between the GOOSE control block listed on vertical line and the device shown on the horizontal line.

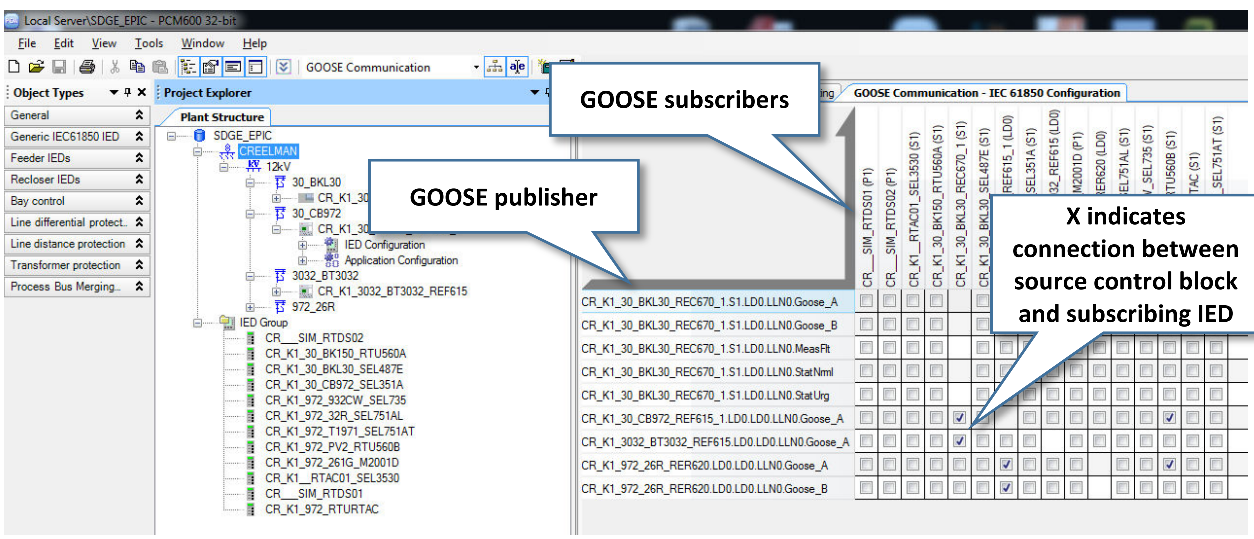


Figure D-9. GOOSE matrix in system engineering tool

C) Use the Vendor 2's configuration tool testing tool to highlight impact of removed IED using data flow view tab: By loading the up-do-date SCD file into the IEC 61850 testing tool Vendor 2's configuration tool and opening the data flow view tab all devices and communication links are graphically shown. Selecting the IEDs targeted for removal to fault simulation (IED will turn into red color) automatically colors communication depending IEDs into orange color. It provides an easy and quick way to identify the IEDs subscribing to the IED that shall be removed.

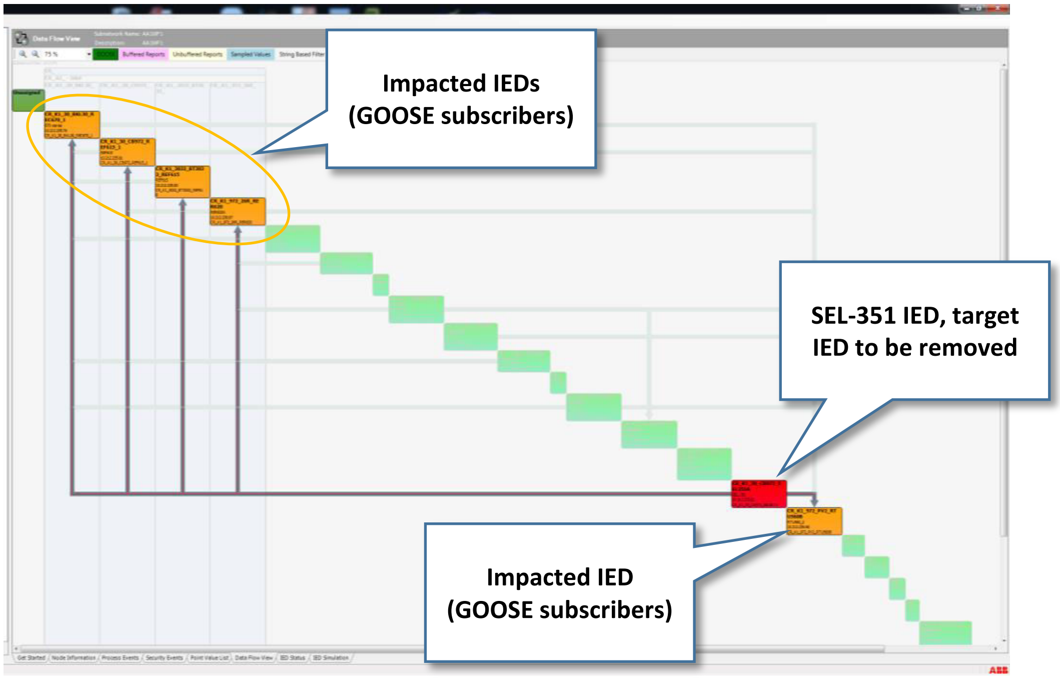
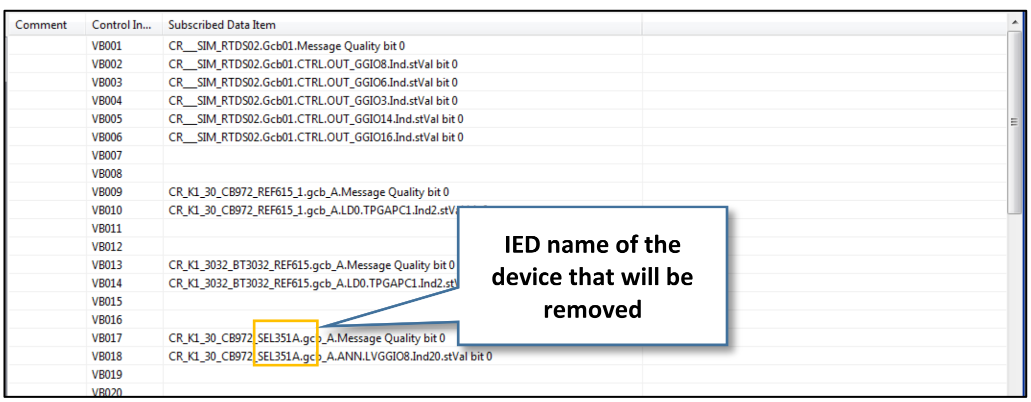


Figure D-10. IEC 61850 testing tool showing data flow view and simulated faulty IED

D) Manual check in IED configuration tools: Manual verification of dependent IEDs is also possible looking at each individual IED and its GOOSE input sections. It is a rather slow process as it required manually opening of each IED and checking the relations.



Comment	Control In...	Subscribed Data Item
	VB001	CR__SIM_RTDS02.Gcb01.Message Quality bit 0
	VB002	CR__SIM_RTDS02.Gcb01.CTRL.OUT_GGIO8.Ind.stVal bit 0
	VB003	CR__SIM_RTDS02.Gcb01.CTRL.OUT_GGIO6.Ind.stVal bit 0
	VB004	CR__SIM_RTDS02.Gcb01.CTRL.OUT_GGIO3.Ind.stVal bit 0
	VB005	CR__SIM_RTDS02.Gcb01.CTRL.OUT_GGIO14.Ind.stVal bit 0
	VB006	CR__SIM_RTDS02.Gcb01.CTRL.OUT_GGIO16.Ind.stVal bit 0
	VB007	
	VB008	
	VB009	CR_K1_30_CB972_REF615_1.gcb_A.Message Quality bit 0
	VB010	CR_K1_30_CB972_REF615_1.gcb_A.LD0.TPGAPC1.Ind2.stV
	VB011	
	VB012	
	VB013	CR_K1_3032_BT3032_REF615.gcb_A.Message Quality bit 0
	VB014	CR_K1_3032_BT3032_REF615.gcb_A.LD0.TPGAPC1.Ind2.st
	VB015	
	VB016	
	VB017	CR_K1_30_CB972_SEL351A.gcb_A.Message Quality bit 0
	VB018	CR_K1_30_CB972_SEL351A.gcb_A.ANN.LVGGIO8.Ind20.stVal bit 0
	VB019	
	VB020	

Figure D-11. GOOSE input section for a single device in Vendor 1 IED tool

Step 2: Remove IED in system and IED tools

There are only a few steps required to remove an active device from an engineering project. First step is to remove it from the IEC 61850 system engineering tool and consequently from the IED configuration tool in case the IED configuration tool holds one project for multiple IEDs. In this project the SEL-351 had to be removed at two locations: In Vendor 2's configuration tool (in this content used as system engineering tool) and in the SEL Architect (IED configuration tool). If an IED would be chosen for removal it would only be required to be deleted once in the Vendor 2's configuration tool as the IED and the IEC 61850 system engineering is handled inside the same tool.

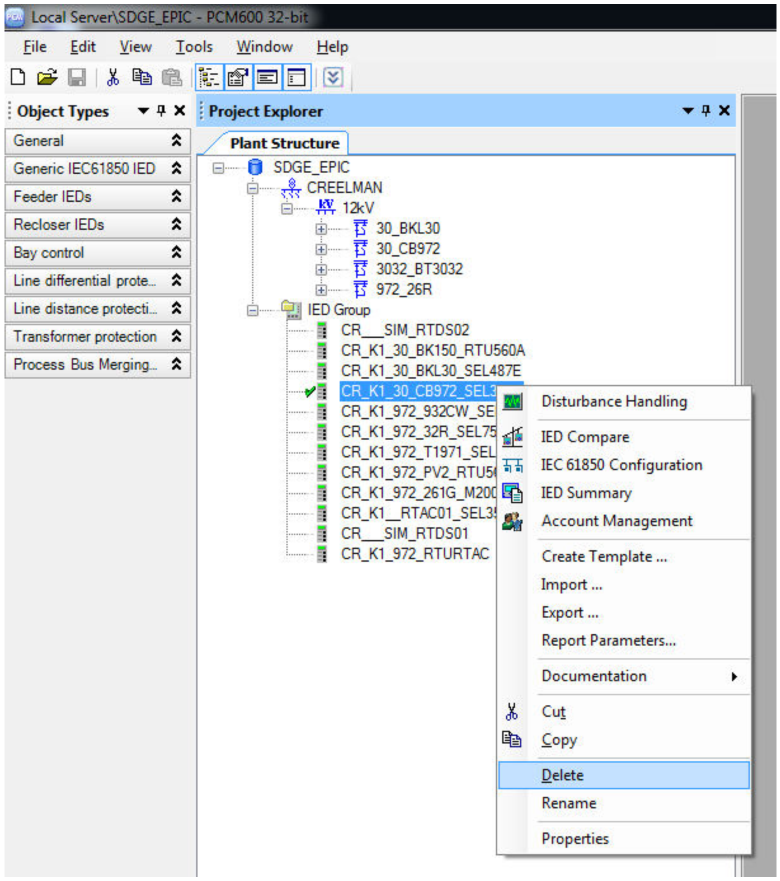


Figure D-12. Deleting and IED in Vendor 2's configuration tool

Step 3: Load all impacted IEDs with new configuration

Finally all impacted IEDs (GOOSE subscribers of the removed IED) need to be loaded with the updated configuration file to make sure they do not subscribe to the GOOSE messages of the removed device anymore.

Beside the IEDs also the MMS client devices such as the station HMI in our set-up need to be loaded with the updated SCD file and related internal data point and graphical elements are removed by manual engineering.

Step 4: Confirm correct configuration and function

The breaker failure function was selected to verify the proper removal of the SEL-351 feeder relay. The SEL-351 is kept in the system and publishes the MMS and GOOSE messages. After removal all data receiver such as GOOSE subscribers will not read the information from the network event thought the message is still there. To prove that a manual trigger in the SEL-351 was used to force the breaker failure

GOOSE message. REC670 the BF GOOSE receiver this not process the information as it was removed as part of the removal engineering process. So correct behavior was proven.

D.1.3 Test Case 3: Replace failed time source device into existing system

The time server is used to synchronize all equipment as part of the system. Four different time sync methods are applied: SNTP, PPS, PTP and IRIG-B. The time master itself does not have an IEC 61850 data model and supervision is in this project kept very simple as it was not a focused area of this project. So it means the reach of the time servers IP address is the main criteria for supervision.

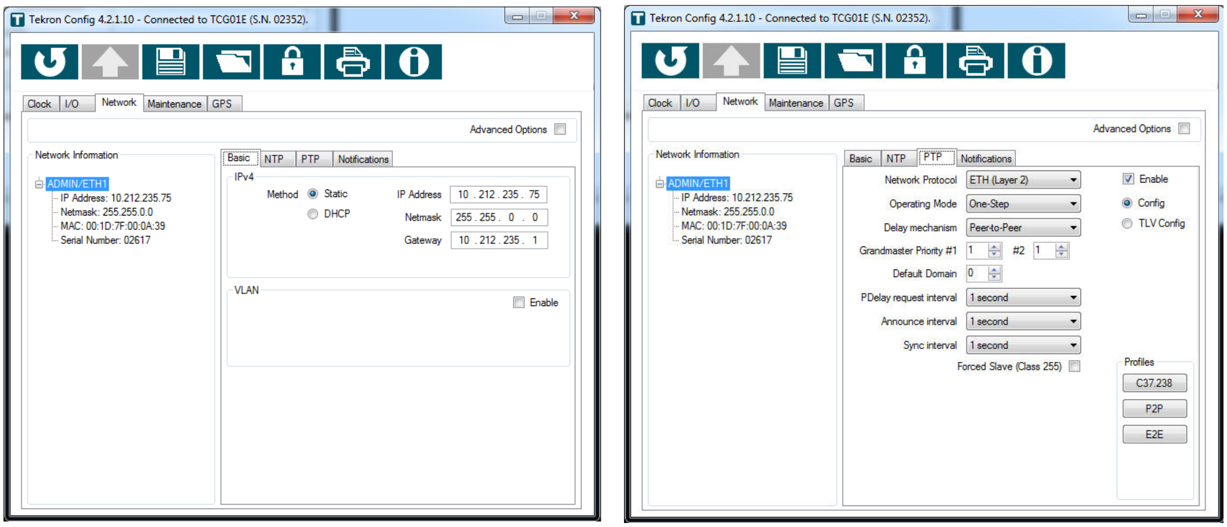


Figure D-13. Tekron Time Server Configuration

In case of a time server failure the operator will be informed about the failure at different levels:

1. System overview picture: An alarm on the time server symbol indicates the failure
2. Alarm list: An active alarm will be shown in the arlarm list
3. Event list: There is also shown an event about the time server failure, and consequently following time tagged events from any IED will be received with a quality flag time faulty that will be shown in the event list with a "T" entry at the beginning of each indivdual event list entry

In practices the faulty time server would be replaced by an equivalent device and the configuration backup is restored to the new time server hardware. There was no need to change any setting for any other device in the system to get time synchronization working again.

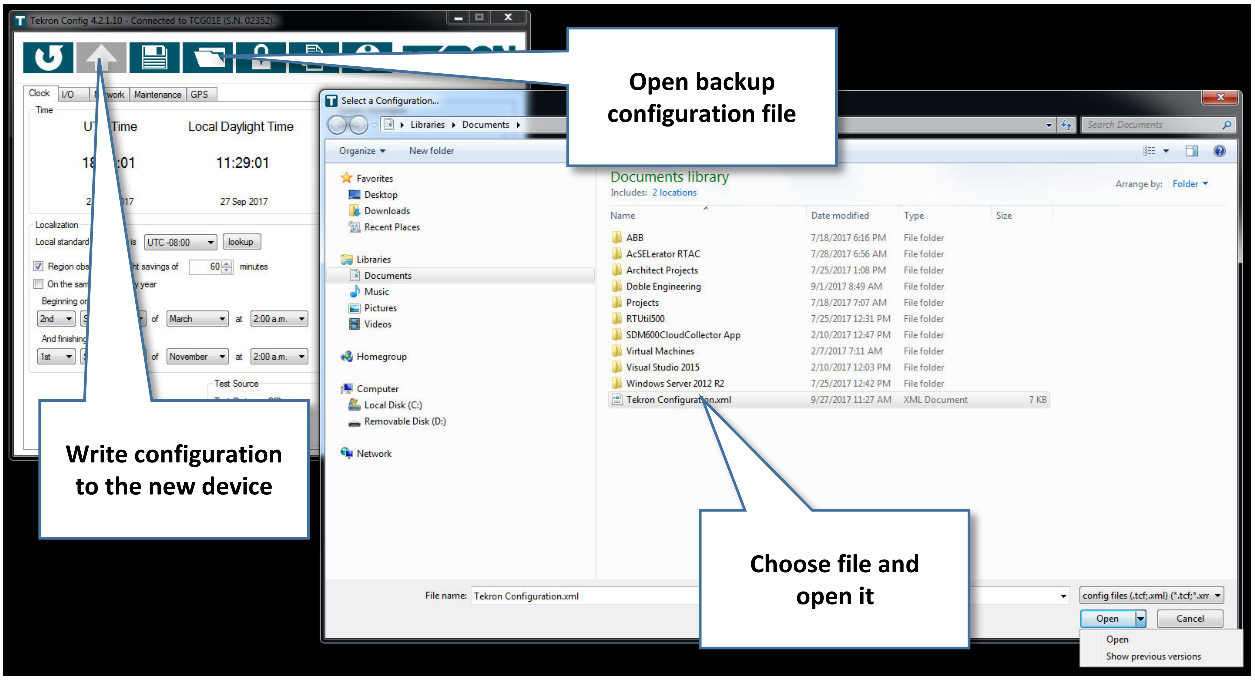


Figure D-14. Open configuration file before downloading to new time master device

Correct working of time synchronization was confirmed by checking the status of the earlier listed three levels of alarm indication.

D.2 Use Case 2: Maintenance testing of IEDs

For this use case the configuration for REC670 and REF615 is changed from IEC 61850 Edition 1 to Edition 2. Table D-1 and Table D-2 provide an overview about the different modes and the behavior according to IEC 61850 Edition 2. Note that blocked mode and behavior had been clarified with a tissue that supersedes the relevant IEC 61850 Edition 2 standard.

Table D-1. Values of mode and behavior according to IEC 61850-7-4 Edition 2

Value	Mode	
1	on	The application represented by the LN works. All communication services work and get updated values
2	on-blocked	The application represented by the LN works. No output data (digital by relays or analogue setting) will be issued to the process. All communication services work and get updated values. Data objects will be transmitted with quality "operatorBlocked". Control commands will be rejected. See note below Table A.1.
3	test	The application represented by the LN works. All communication services work and get updated values. Data objects will be transmitted with quality "test". Control commands with quality test will be accepted only by LNs in "test" or "test-blocked" mode. "Processed as valid" means that the application should react in the manner what is foreseen for "test".
4	test/blocked	The application represented by the LN works. No output data (digital by relays or analogue setting) will be issued to the process. All communication services work and get updated values. Data objects will be transmitted with quality "test". Control commands with quality test will be accepted only by LNs in TEST or TEST-Blocked mode.
5	off	The application represented by the LN doesn't work. No process output is possible. No control command should be acknowledged (negative response). Only the data object Mod and Beh should be accessible by the services.
NOTE The Mod ="blocked" from edition 1 is changed in edition 2 to "on-blocked".		

Table D-2 Tissue values of mode and behavior for blocked

2	blocked	The application represented by the LN works. No (wired) output data (digital by relays or analogue setpoints) will be issued to the process. All communication services work and get updated values. Data objects will be transmitted with a relevant quality. Control commands with Test=false will be accepted. Control commands with Test=true will be rejected (negative acknowledgment with AddCause=Blocked-by-Mode).

Table D-3. Quality bit definition table according IEC 61850-7-3 Edition 2

Quality type definition			
Attribute name	**Attribute type**	**Value/Value range**	**M/O/C**
	PACKED LIST		
validity	CODED ENUM	good | invalid | reserved | questionable	M
detailQual	PACKED LIST		M
overflow	BOOLEAN	DEFAULT FALSE	M
outOfRange	BOOLEAN	DEFAULT FALSE	M
badReference	BOOLEAN	DEFAULT FALSE	M
oscillatory	BOOLEAN	DEFAULT FALSE	M
failure	BOOLEAN	DEFAULT FALSE	M
oldData	BOOLEAN	DEFAULT FALSE	M
inconsistent	BOOLEAN	DEFAULT FALSE	M
inaccurate	BOOLEAN	DEFAULT FALSE	M
source	CODED ENUM	process | substituted DEFAULT process	M
test	BOOLEAN	DEFAULT FALSE	M
operatorBlocked	BOOLEAN	DEFAULT FALSE	M

D.2.1 Test Case 1: IEC 61850 Edition2, Mode: On

This is the normal operation mode for IEDs. The status of the publisher and subscriber is as followed:

Publisher: REF615, Mod/Beh = ON, q = good
Subscriber: REC670, Mod/Beh = ON, q = good

To verify the correct behavior the breaker position of the REF615 is published as GOOSE message. The REC670 subscribes to that GOOSE message.

Step 1: Change mode of the IED

The mode of the IED is changed using Vendor 2's configuration tool of from the IEDs HMI.

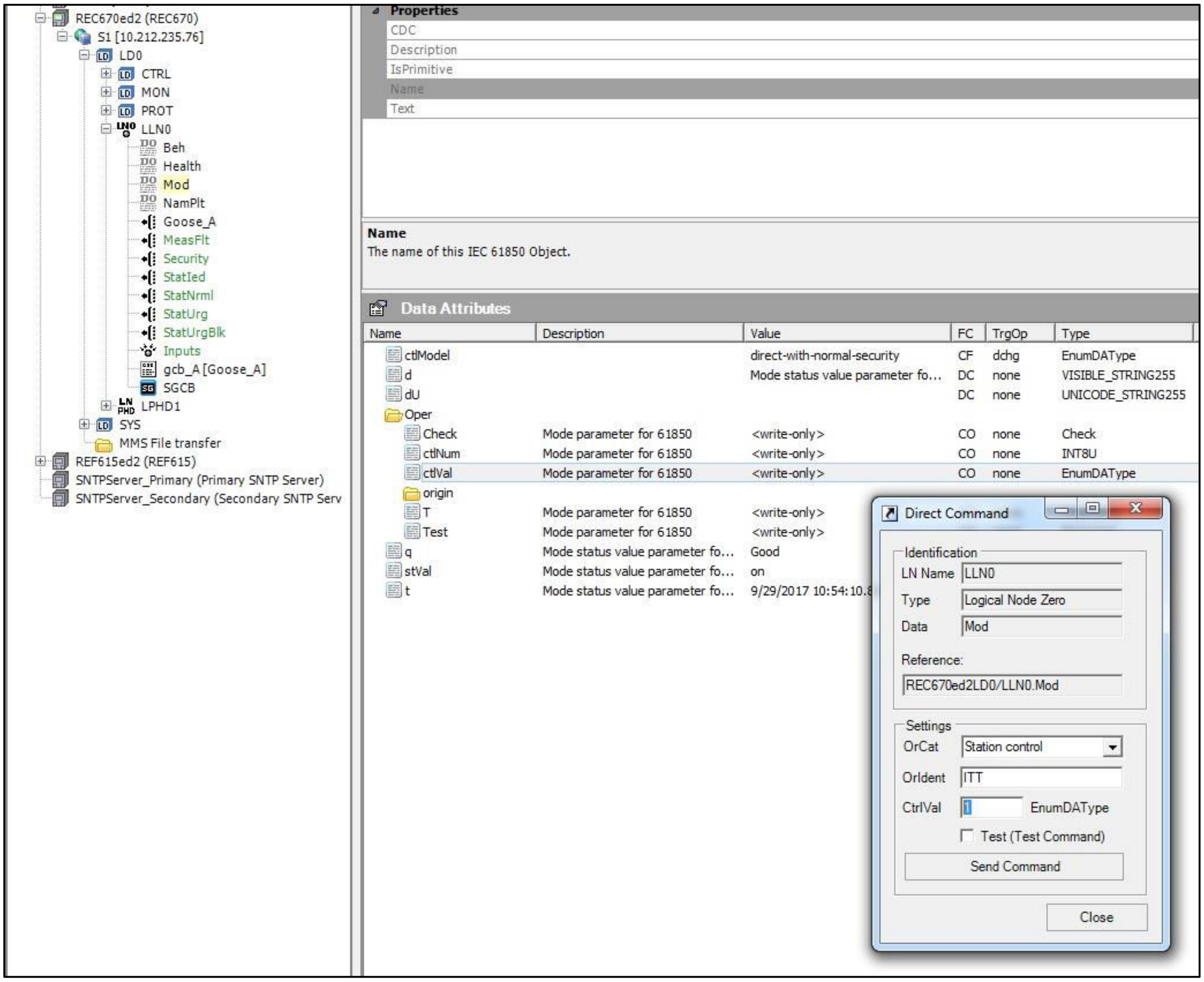


Figure D-15. Setting mode in Vendor 2's configuration tool for REC670

Step 2: Check correct circuit breaker status in subscriber IED

The circuit breaker status at the REF615 was closed. To verify the correctly received value at the REC670 the online status monitoring of the logic residing inside the REC670 is used:

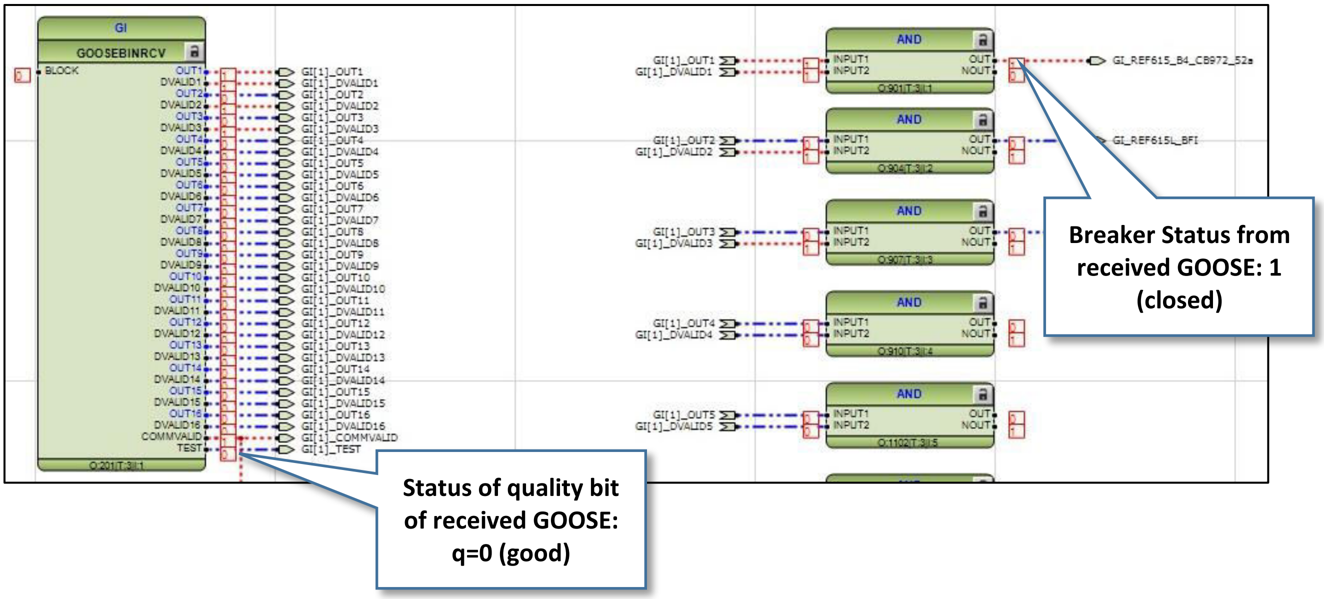


Figure D-16. Online status of received GOOSE (q=good) in REC670 (mode=on)

Step 3: Check captured message on the station bus

The capture of the GOOSE message demonstrates the status change and the quality bit information:

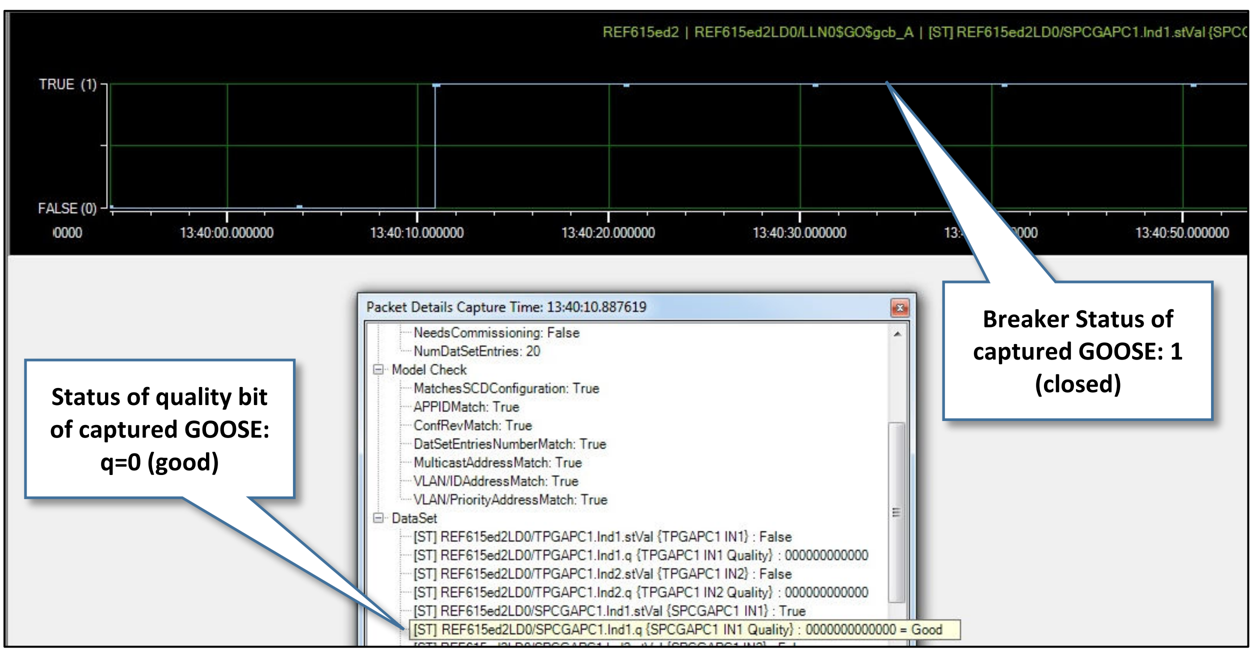


Figure D-17. Captured GOOSE (q=good) message sent by REF615

D.2.2 Test Case 2: IEC 61850 Edition2, Mode: Test

In this situation the IED in mode=test is isolated from IEDs in normal operation. Meaning the IEDs under normal operation will ignore the GOOSE message from the IED in test mode.

Publisher: REF615, Mod/Beh = Test, q=test
Subscriber: REC670, Mod/Beh = ON, q= good

To verify the correct behavior the breaker position of the REF615 is published as GOOSE message. The REC670 subscribes to that GOOSE message. The subscriber should receive the test GOOSE message but not process the status value.

Step 1: Change mode of the IED

The mode of the REF615 is changed using Vendor 2's configuration tool to "test".

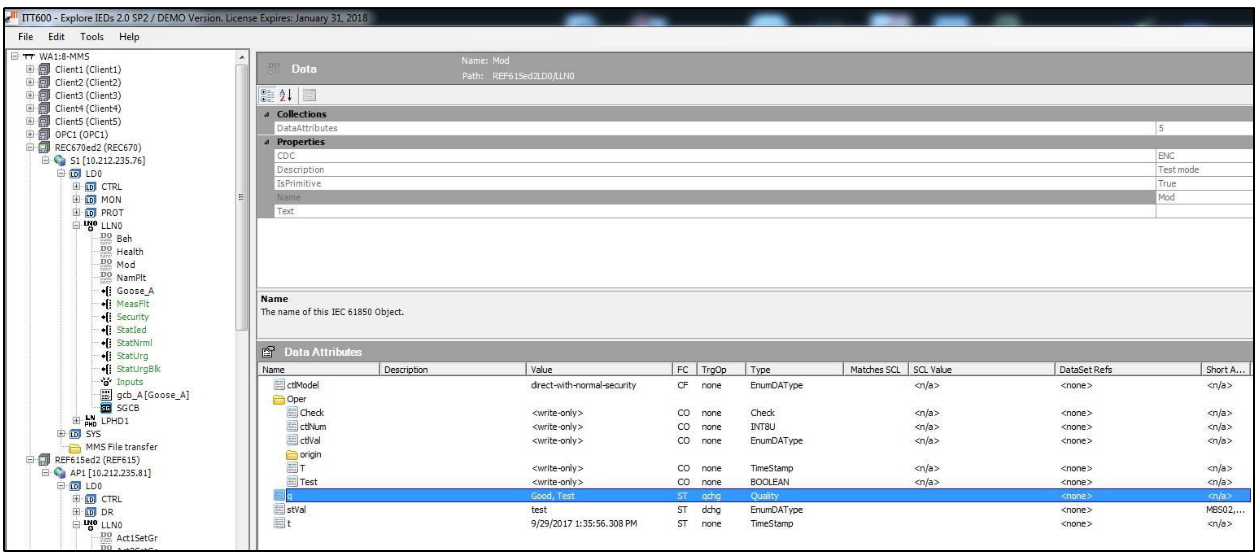


Figure D-18. Setting mode in Vendor 2's configuration tool for REF615

Step 2: Check correct circuit breaker status in the subscriber IED

The circuit breaker status at the REF615 was closed. To verify the correctly received value at the REC670 the online status monitoring of the logic residing inside the REC670 is used:

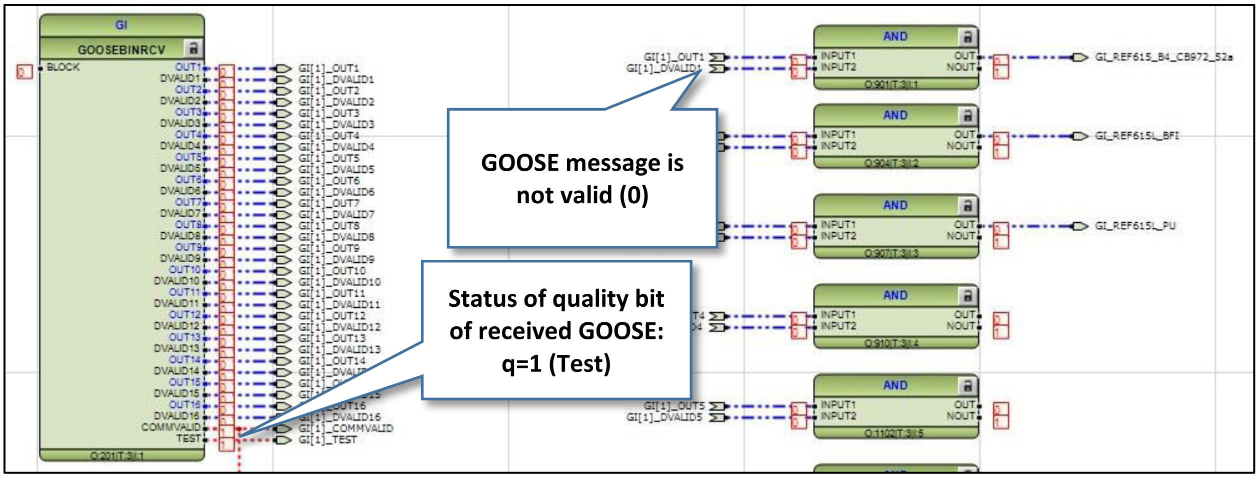


Figure D-19. Online status of received GOOSE (q=test) in REC670 (mode=on)

Step 3: Check captured message on the station bus

The capture of the GOOSE message demonstrates the status change and the quality bit information:

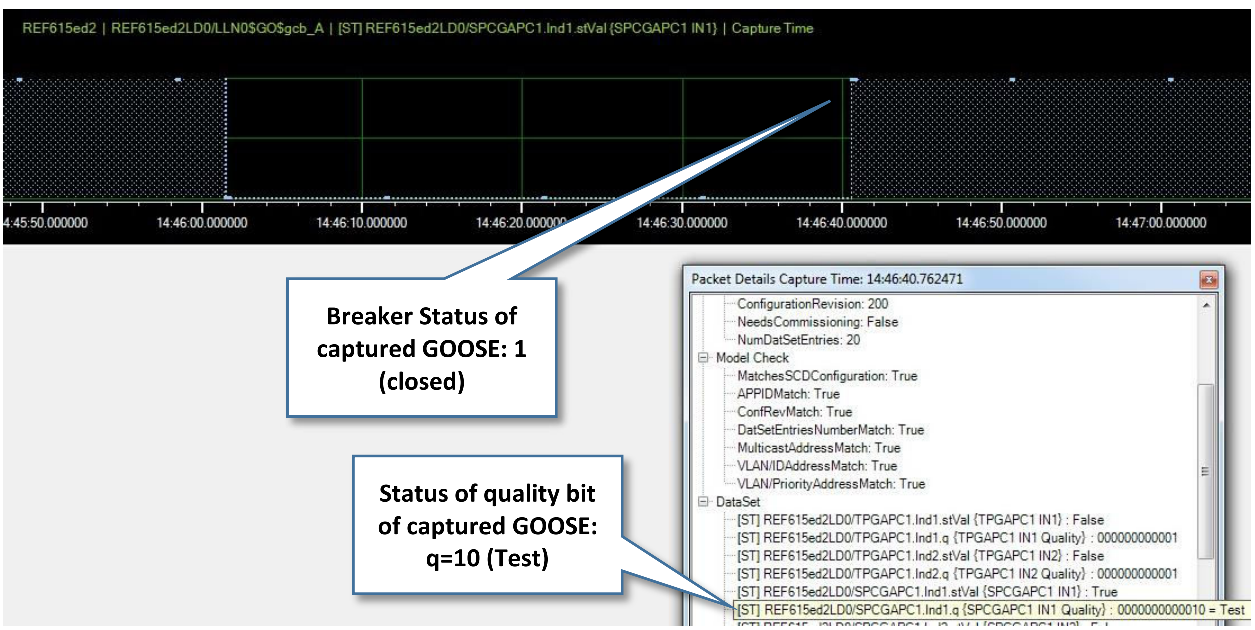


Figure D-20. Captured GOOSE (q=test) message sent by REF615

D.2.3 Test Case 3: IEC 61850 Edition2, Both IEDs Mode: Test

In this situation both IEDs are isolated from the rest of the system as both are set into mode=test. Meaning the both IEDs under test will now accept the GOOSE message from each other.

Publisher: REF615, Mod/Beh = Test, q=test
Subscriber: REC670, Mod/Beh = Test, q= test

To verify the correct behavior the breaker position of the REF615 is published as GOOSE message. The REC670 subscribes to that GOOSE message. The subscriber should receive the test GOOSE message and process it.

Step 1: Change mode of the IED

The mode of the REC670 is changed using Vendor 2's configuration tool to "test". Note the REF615 is already in test mode from the previous test case.

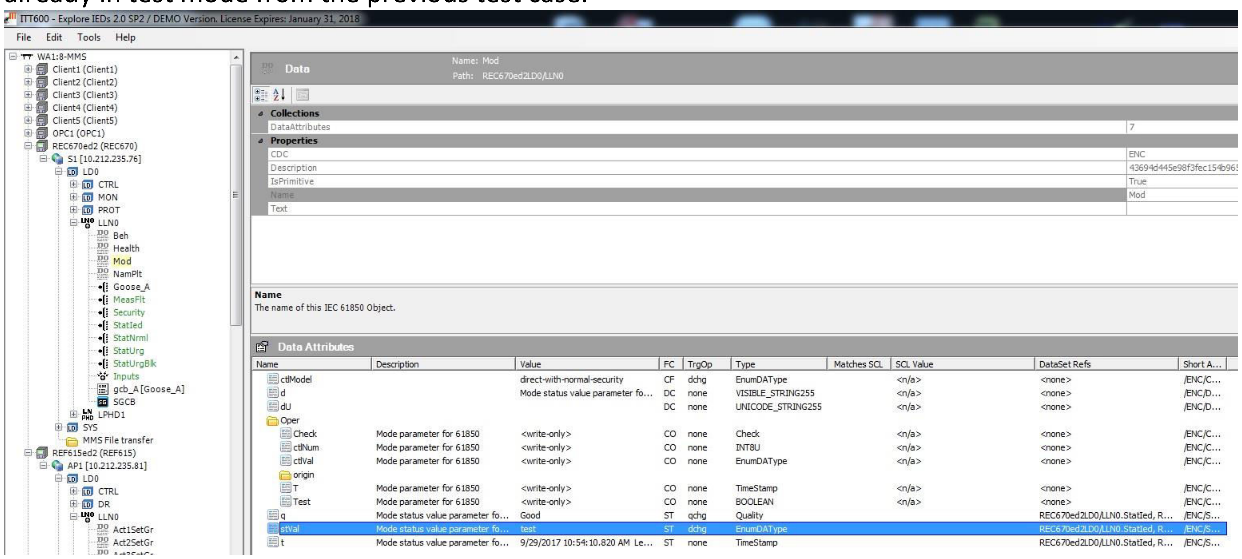


Figure D-21. Setting mode to "test" in Vendor 2's configuration tool for REC670

Step 2: Check correct circuit breaker status in the subscriber IED

The circuit breaker status at the REF615 was opened. To verify the correctly received value at the REC670 the online status monitoring of the logic residing inside the REC670 is used:

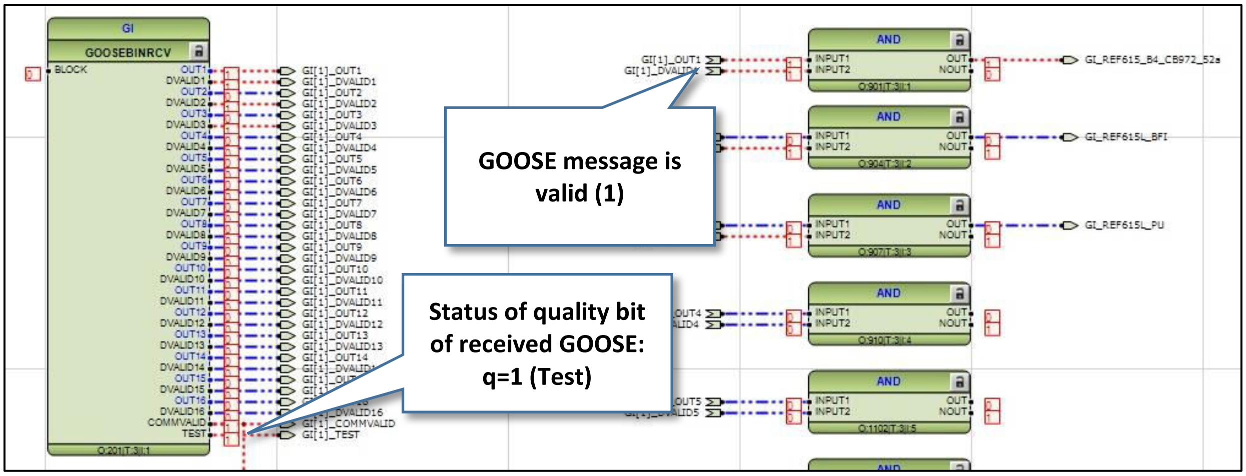


Figure D-22. Online status of received GOOSE (q=test) in REC670 (mode=test)

Step 3: Check captured message on the station bus

The capture of a general trip GOOSE message from REC670 triggered by received SV with q=test from the REF615 demonstrates that both IEDs behave correctly.

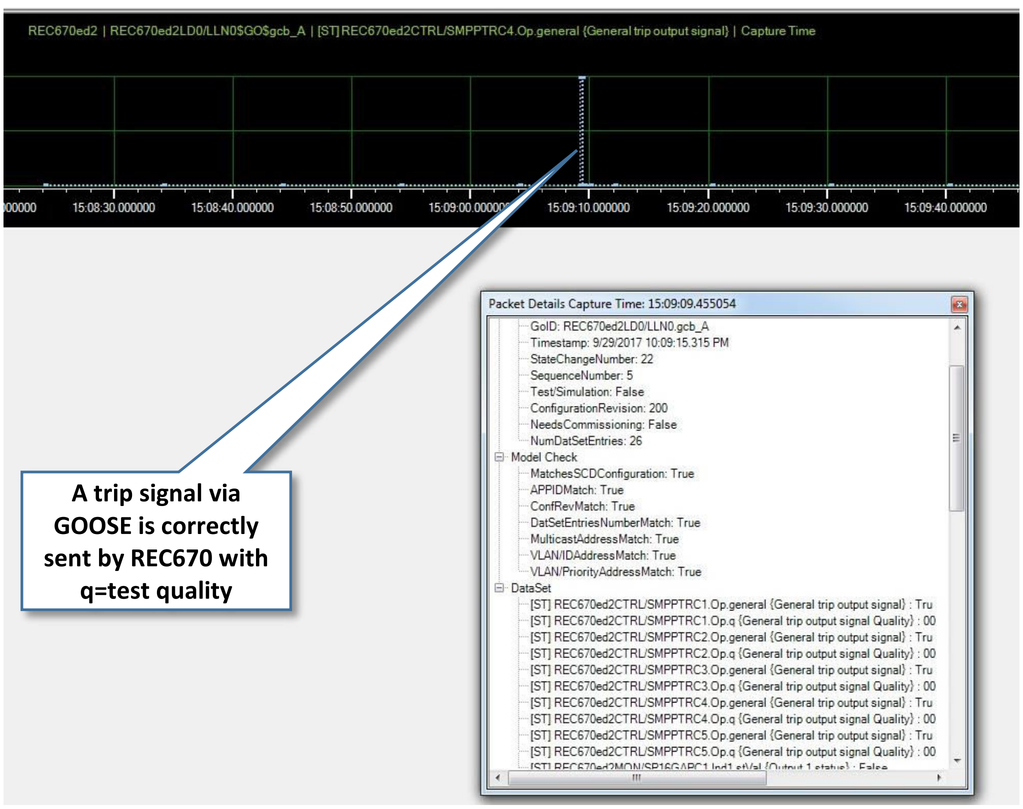


Figure D-23. Captured GOOSE (q=good) message sent by REC670

D.2.4 Test Case 4: IEC 61850 Edition2, Mode: Test/Blocked

In this situation as both IEDs are in test mode they are isolated from IEDs in normal operation. Meaning the IEDs under normal operation will ignore the GOOSE messages from the IEDs in test mode. The subscriber is additionally blocked and shall not control outputs.

Publisher: REF615, Mod/Beh = Test, q=test
Subscriber: REC670, Mod/Beh = Test/Blocked, q= good

Note: In order to not trip the output contact, either the signal needs to be connected to a LN related to a primary equipment such as XCBR or the LN needs to be linked to the block signal.

Step 1: Set REC670 to Test/Block mode, REF615 is already in Test mode from previous test case

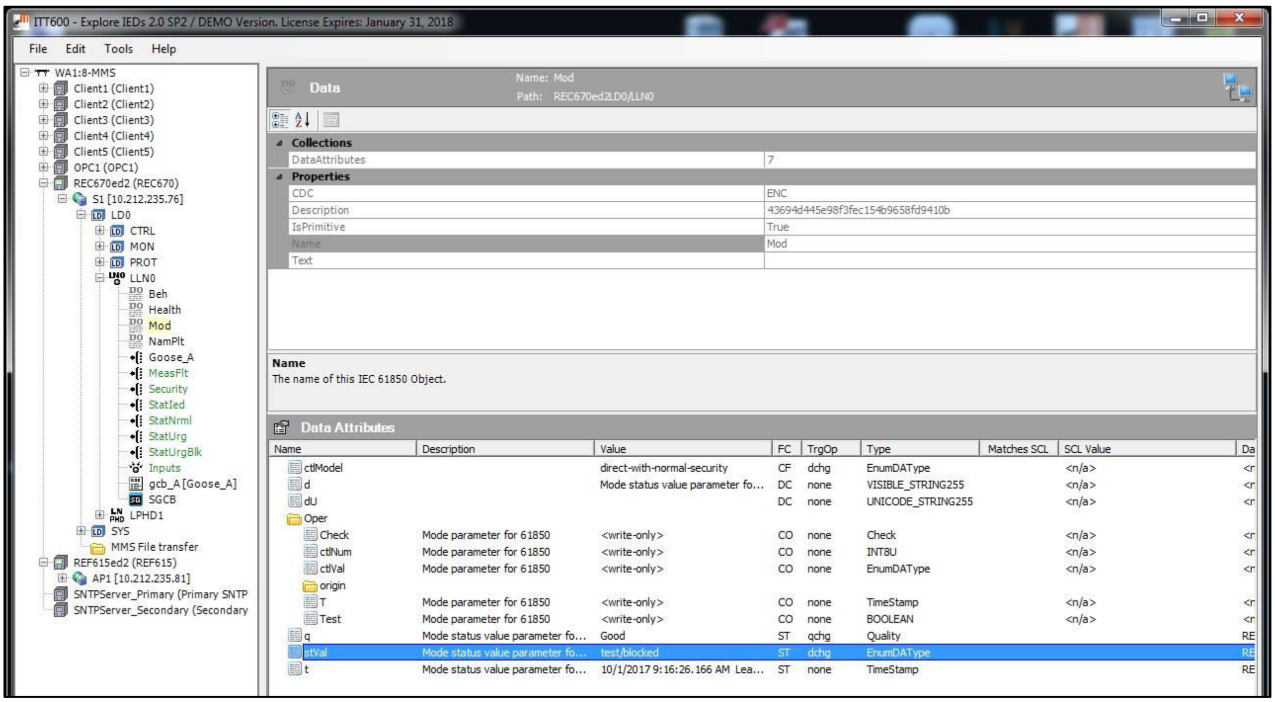


Figure D-24. Setting mode to “test/blocked” in Vendor 2’s configuration tool for REC670

Step 2: Simulate overcurrent situation using RTDS injecting to REF615 and observe correct GOOSE trip message in Vendor 2's configuration tool

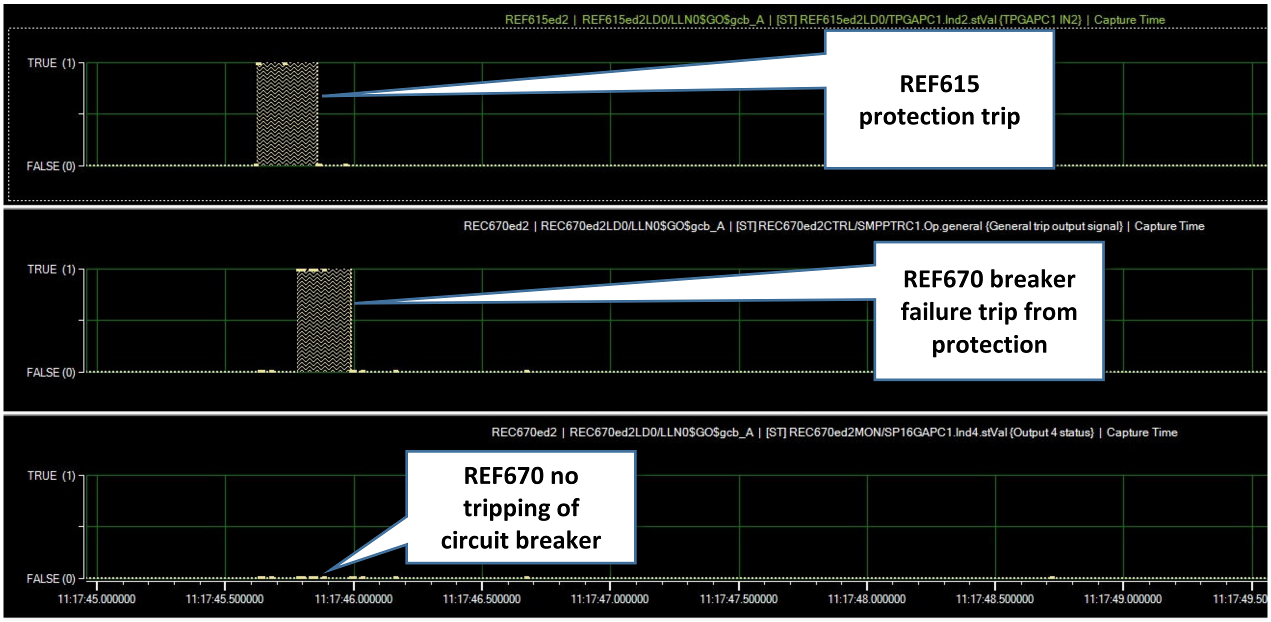
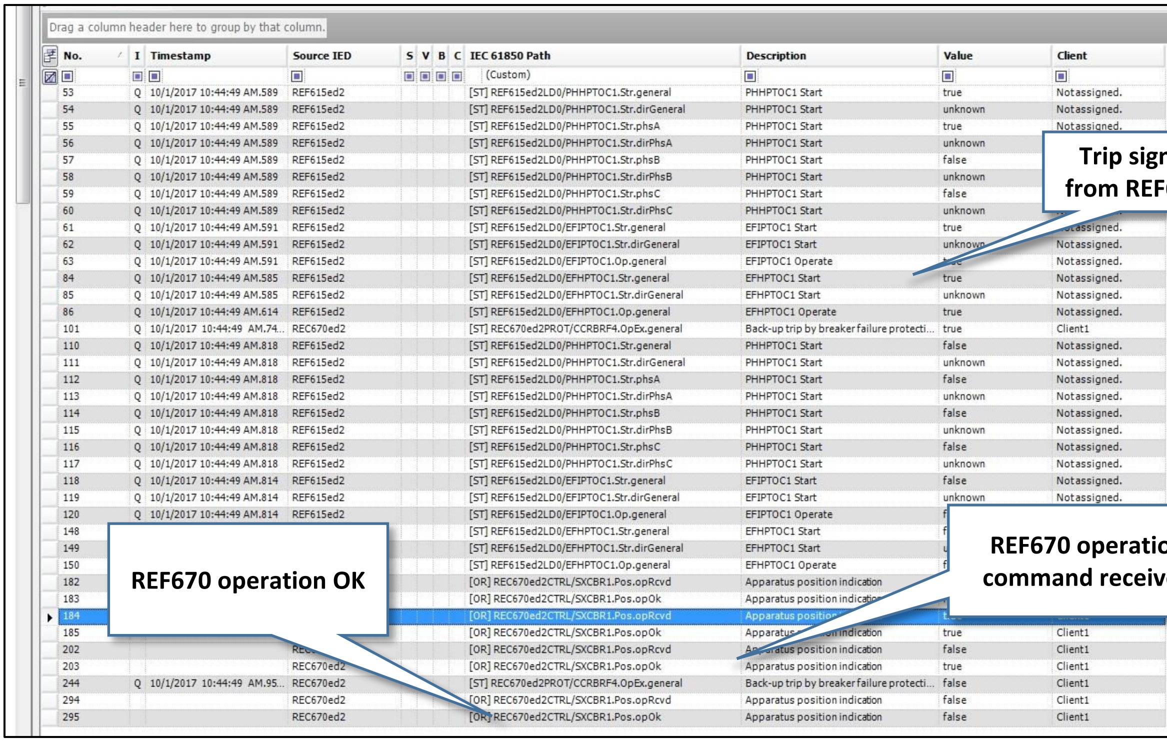


Figure D-25. Captured GOOSE messages with test and test/blocked modes

Step 3: Confirm correct behavior checking relevant events received by Vendor 2's configuration tool as an MMS client to REF615 and REC670.



Drag a column header here to group by that column.

No.	I	Timestamp	Source IED	S	V	B	C	IEC 61850 Path	Description	Value	Client
								(Custom)			
53	Q	10/1/2017 10:44:49 AM.589	REF615ed2					[ST] REF615ed2LD0/PHHPTOC1.Str.general	PHHPTOC1 Start	true	Notassigned.
54	Q	10/1/2017 10:44:49 AM.589	REF615ed2					[ST] REF615ed2LD0/PHHPTOC1.Str.dirGeneral	PHHPTOC1 Start	unknown	Notassigned.
55	Q	10/1/2017 10:44:49 AM.589	REF615ed2					[ST] REF615ed2LD0/PHHPTOC1.Str.phsA	PHHPTOC1 Start	true	Notassigned.
56	Q	10/1/2017 10:44:49 AM.589	REF615ed2					[ST] REF615ed2LD0/PHHPTOC1.Str.dirPhsA	PHHPTOC1 Start	unknown	[illegible]
57	Q	10/1/2017 10:44:49 AM.589	REF615ed2					[ST] REF615ed2LD0/PHHPTOC1.Str.phsB	PHHPTOC1 Start	false	[illegible]
58	Q	10/1/2017 10:44:49 AM.589	REF615ed2					[ST] REF615ed2LD0/PHHPTOC1.Str.dirPhsB	PHHPTOC1 Start	unknown	[illegible]
59	Q	10/1/2017 10:44:49 AM.589	REF615ed2					[ST] REF615ed2LD0/PHHPTOC1.Str.phsC	PHHPTOC1 Start	false	[illegible]
60	Q	10/1/2017 10:44:49 AM.589	REF615ed2					[ST] REF615ed2LD0/PHHPTOC1.Str.dirPhsC	PHHPTOC1 Start	unknown	[illegible]
61	Q	10/1/2017 10:44:49 AM.591	REF615ed2					[ST] REF615ed2LD0/EFIPTOC1.Str.general	EFIPTOC1 Start	true	[illegible]
62	Q	10/1/2017 10:44:49 AM.591	REF615ed2					[ST] REF615ed2LD0/EFIPTOC1.Str.dirGeneral	EFIPTOC1 Start	unknown	Notassigned.
63	Q	10/1/2017 10:44:49 AM.591	REF615ed2					[ST] REF615ed2LD0/EFIPTOC1.Op.general	EFIPTOC1 Operate	[illegible]	Notassigned.
84	Q	10/1/2017 10:44:49 AM.585	REF615ed2					[ST] REF615ed2LD0/EFHPTOC1.Str.general	EFHPTOC1 Start	true	Notassigned.
85	Q	10/1/2017 10:44:49 AM.585	REF615ed2					[ST] REF615ed2LD0/EFHPTOC1.Str.dirGeneral	EFHPTOC1 Start	unknown	Notassigned.
86	Q	10/1/2017 10:44:49 AM.614	REF615ed2					[ST] REF615ed2LD0/EFHPTOC1.Op.general	EFHPTOC1 Operate	true	Notassigned.
101	Q	10/1/2017 10:44:49 AM.74...	REC670ed2					[ST] REC670ed2PROT/CCRBRF4.OpEx.general	Back-up trip by breaker failure protecti...	true	Client1
110	Q	10/1/2017 10:44:49 AM.818	REF615ed2					[ST] REF615ed2LD0/PHHPTOC1.Str.general	PHHPTOC1 Start	false	Notassigned.
111	Q	10/1/2017 10:44:49 AM.818	REF615ed2					[ST] REF615ed2LD0/PHHPTOC1.Str.dirGeneral	PHHPTOC1 Start	unknown	Notassigned.
112	Q	10/1/2017 10:44:49 AM.818	REF615ed2					[ST] REF615ed2LD0/PHHPTOC1.Str.phsA	PHHPTOC1 Start	false	Notassigned.
113	Q	10/1/2017 10:44:49 AM.818	REF615ed2					[ST] REF615ed2LD0/PHHPTOC1.Str.dirPhsA	PHHPTOC1 Start	unknown	Notassigned.
114	Q	10/1/2017 10:44:49 AM.818	REF615ed2					[ST] REF615ed2LD0/PHHPTOC1.Str.phsB	PHHPTOC1 Start	false	Notassigned.
115	Q	10/1/2017 10:44:49 AM.818	REF615ed2					[ST] REF615ed2LD0/PHHPTOC1.Str.dirPhsB	PHHPTOC1 Start	unknown	Notassigned.
116	Q	10/1/2017 10:44:49 AM.818	REF615ed2					[ST] REF615ed2LD0/PHHPTOC1.Str.phsC	PHHPTOC1 Start	false	Notassigned.
117	Q	10/1/2017 10:44:49 AM.818	REF615ed2					[ST] REF615ed2LD0/PHHPTOC1.Str.dirPhsC	PHHPTOC1 Start	unknown	Notassigned.
118	Q	10/1/2017 10:44:49 AM.814	REF615ed2					[ST] REF615ed2LD0/EFIPTOC1.Str.general	EFIPTOC1 Start	false	Notassigned.
119	Q	10/1/2017 10:44:49 AM.814	REF615ed2					[ST] REF615ed2LD0/EFIPTOC1.Str.dirGeneral	EFIPTOC1 Start	unknown	Notassigned.
120	Q	10/1/2017 10:44:49 AM.814	REF615ed2					[ST] REF615ed2LD0/EFIPTOC1.Op.general	EFIPTOC1 Operate	[illegible]	[illegible]
148	[illegible]	[illegible]	[illegible]					[ST] REF615ed2LD0/EFHPTOC1.Str.general	EFHPTOC1 Start	[illegible]	[illegible]
149	[illegible]	[illegible]	[illegible]					[ST] REF615ed2LD0/EFHPTOC1.Str.dirGeneral	EFHPTOC1 Start	[illegible]	[illegible]
150	[illegible]	[illegible]	[illegible]					[ST] REF615ed2LD0/EFHPTOC1.Op.general	EFHPTOC1 Operate	[illegible]	[illegible]
182	[illegible]	[illegible]	[illegible]					[OR] REC670ed2CTRL/SXCBR1.Pos.opRcvd	Apparatus position indication	[illegible]	[illegible]
183	[illegible]	[illegible]	[illegible]					[OR] REC670ed2CTRL/SXCBR1.Pos.opOk	Apparatus position indication	[illegible]	[illegible]
184	[illegible]	[illegible]	[illegible]					[OR] REC670ed2CTRL/SXCBR1.Pos.opRcvd	Apparatus position [illegible]	[illegible]	[illegible]
185	[illegible]	[illegible]	[illegible]					[OR] REC670ed2CTRL/SXCBR1.Pos.opOk	Apparatus [illegible] indication	true	Client1
202			[illegible]					[OR] REC670ed2CTRL/SXCBR1.Pos.opRcvd	Apparatus position indication	false	Client1
203			REC670ed2					[OR] REC670ed2CTRL/SXCBR1.Pos.opOk	Apparatus position indication	true	Client1
244	Q	10/1/2017 10:44:49 AM.95...	REC670ed2					[ST] REC670ed2PROT/CCRBRF4.OpEx.general	Back-up trip by breaker failure protecti...	false	Client1
294			REC670ed2					[OR] REC670ed2CTRL/SXCBR1.Pos.opRcvd	Apparatus position indication	false	Client1
295			REC670ed2					[OR] REC670ed2CTRL/SXCBR1.Pos.opOk	Apparatus position indication	false	Client1

Figure D-26. Captured events from REC670 and REF615

Step 4: Confirm the correct operation in case both REC670 and REF615 are in test mode

In this scenario the GOOSE message connected to the REC670 XCBR position should be published with q=test compared to the situation in step 2 where it is not published because REC670 was in test/blocked mode.

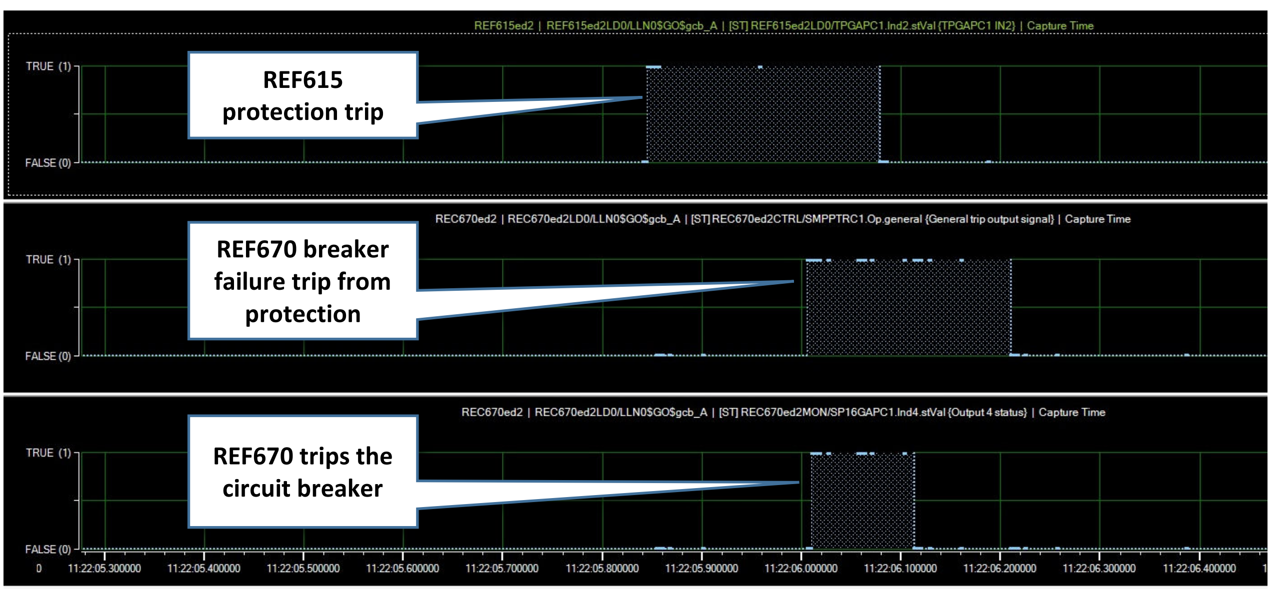


Figure D-27. Captured GOOSE messages with test and test modes

D.2.5 Test Case 5: IEC 61850 Edition2, Simulation: Off

This is the normal operation mode for IEDs. The status of the publisher and subscriber is as followed:

Publisher: Omicron CMC850, Simulation = OFF
Subscriber: REC670 - BKL30, LPHD.Sim = off

To verify the correct behavior the measurement on the REC670 HMI is compared to the value submitted by SAM600 and injected by RTDS.

D.2.6 Test Case 6: IEC 61850 Edition2, Simulation: On

This is the situation where test-set is connected and the IED subscribes to the measurements from the test-set.

Publisher: Omicron CMC850, Simulation = On
Subscriber: REC670 - BKL30, LPHD.Sim = On

To verify the correct behavior the measurement on the REC670 HMI is compared to the value injected by the test-set.

Step 1: Connect test-set and inject simulated sampled values

Before starting simulation in the omicron test-set, the simulation flag is set to simulated.

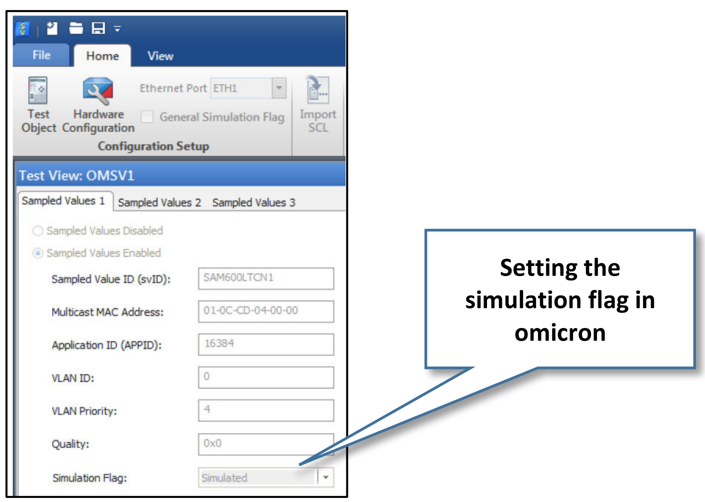


Figure D-28. Setting Simulation Flag in Omicron Tool

Step 2: The following values are injected to the process bus:

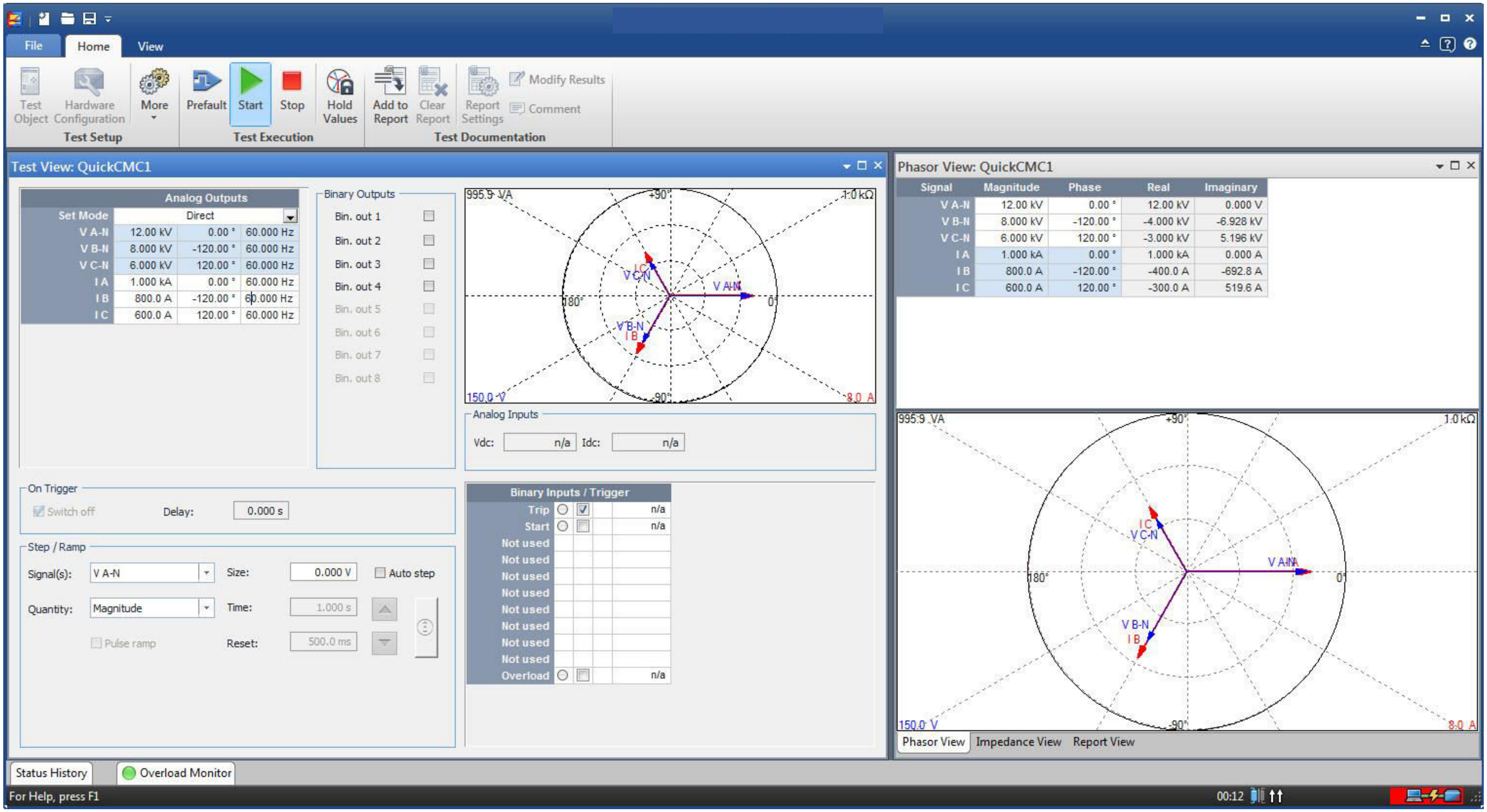
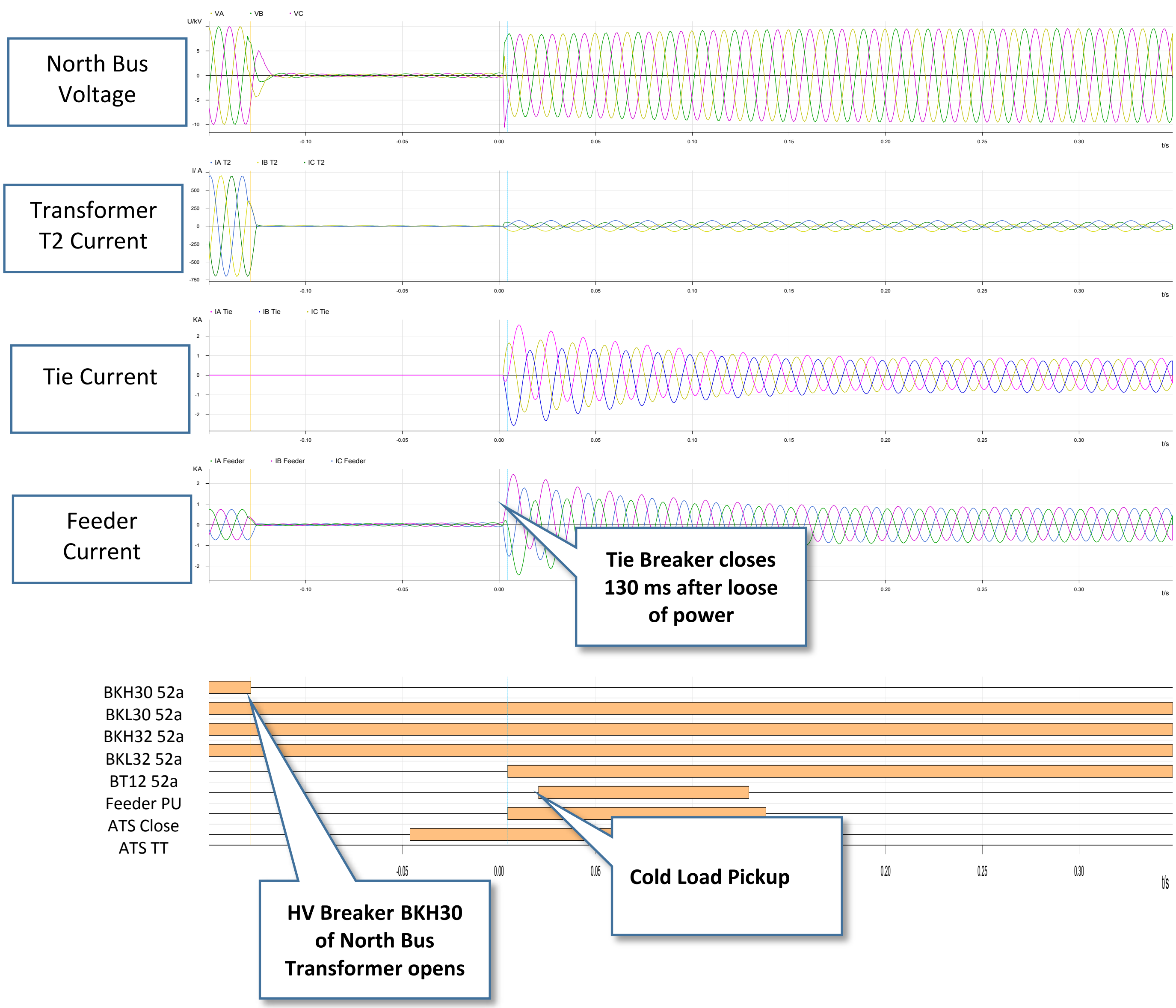


Figure D-29. Omicron Tool: Simulated SV streams

D.3 Use Case 4: Automatic transfer scheme

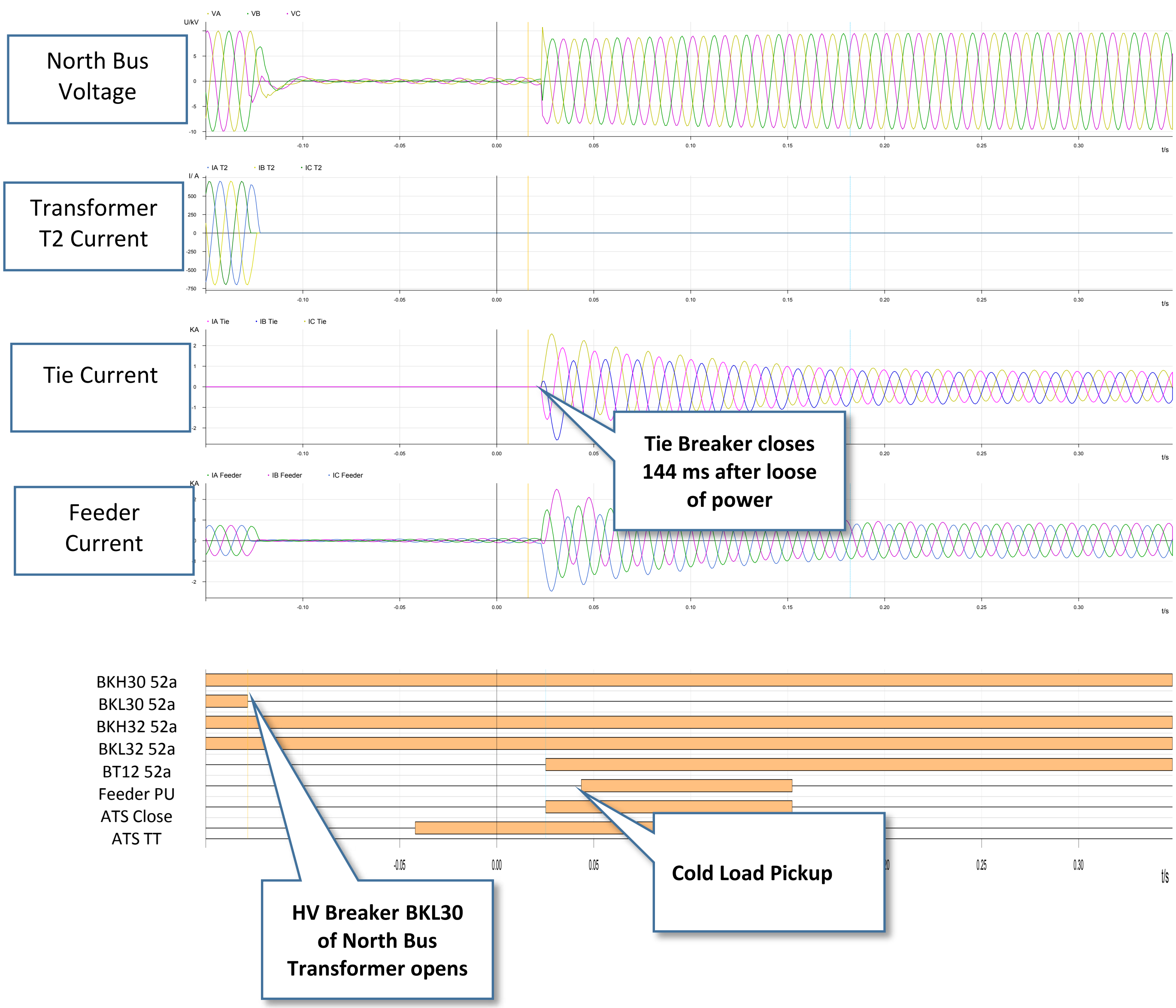
D.3.1 Test Case 1: HV-Side north bus transformer breaker opens

Case	Test Case	Description	Results IEC 61850 Design
1	HV-side North Bus transformer breaker BKH30 opens	• All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized • Disconnect source by opening HV breaker of North Bus transformer T2 (BKH30) • Automatic transfer scheme is started • Check correct operation • Capture measurements and events using DFR	Scheme transferred correctly after 130 ms



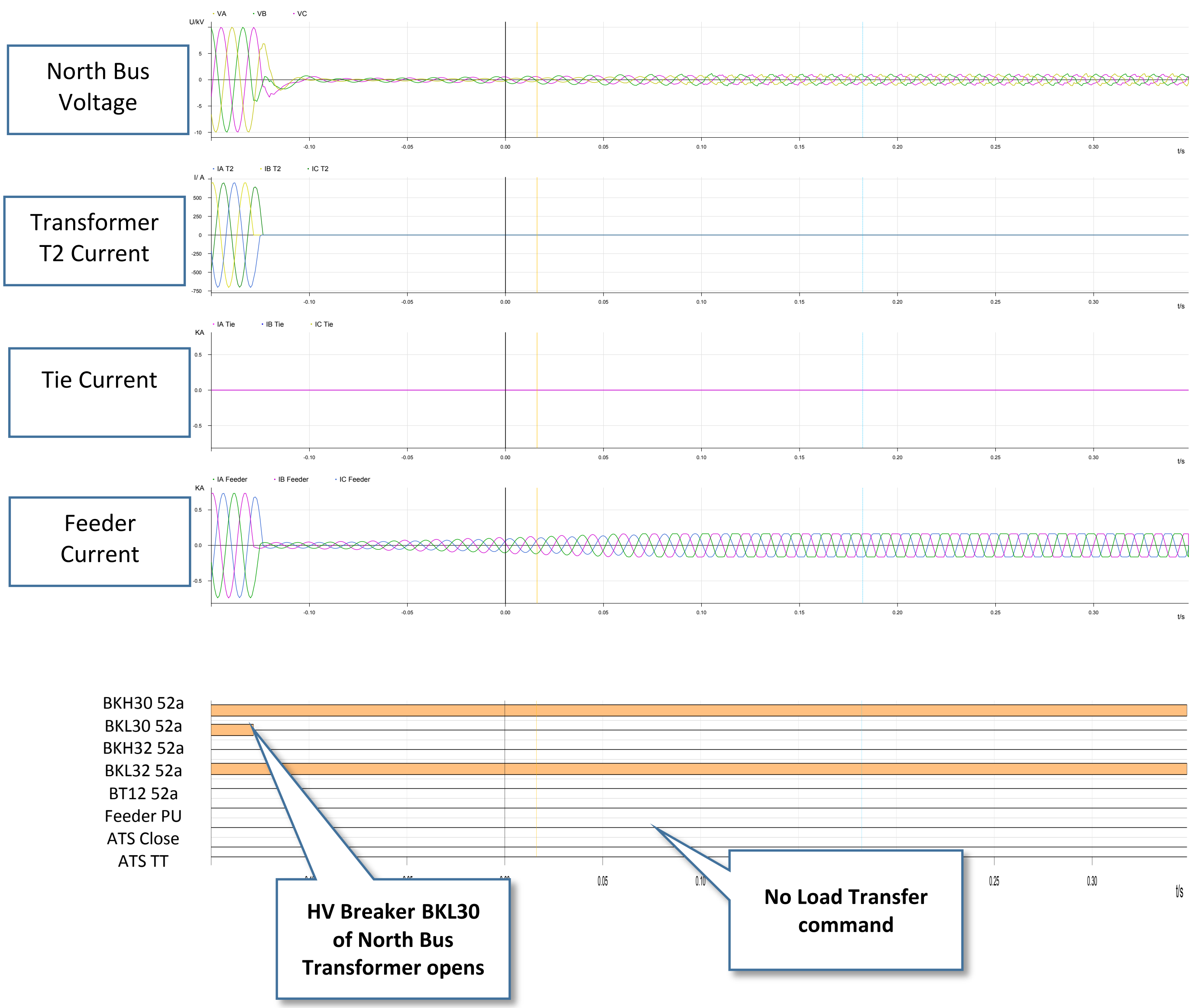
D.3.2 Test Case 2: MV side north bus transformer breaker opens

Case	Test Case	Description	Results IEC 61850 Design
2	MV-side North Bus transformer breaker BKL30 opens	• All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized • Disconnect source by opening MV breaker of North Bus transformer T2 (BKL30) • Automatic transfer scheme is started • Check correct operation • Capture measurements and events using DFR	Scheme transferred correctly after 144 ms



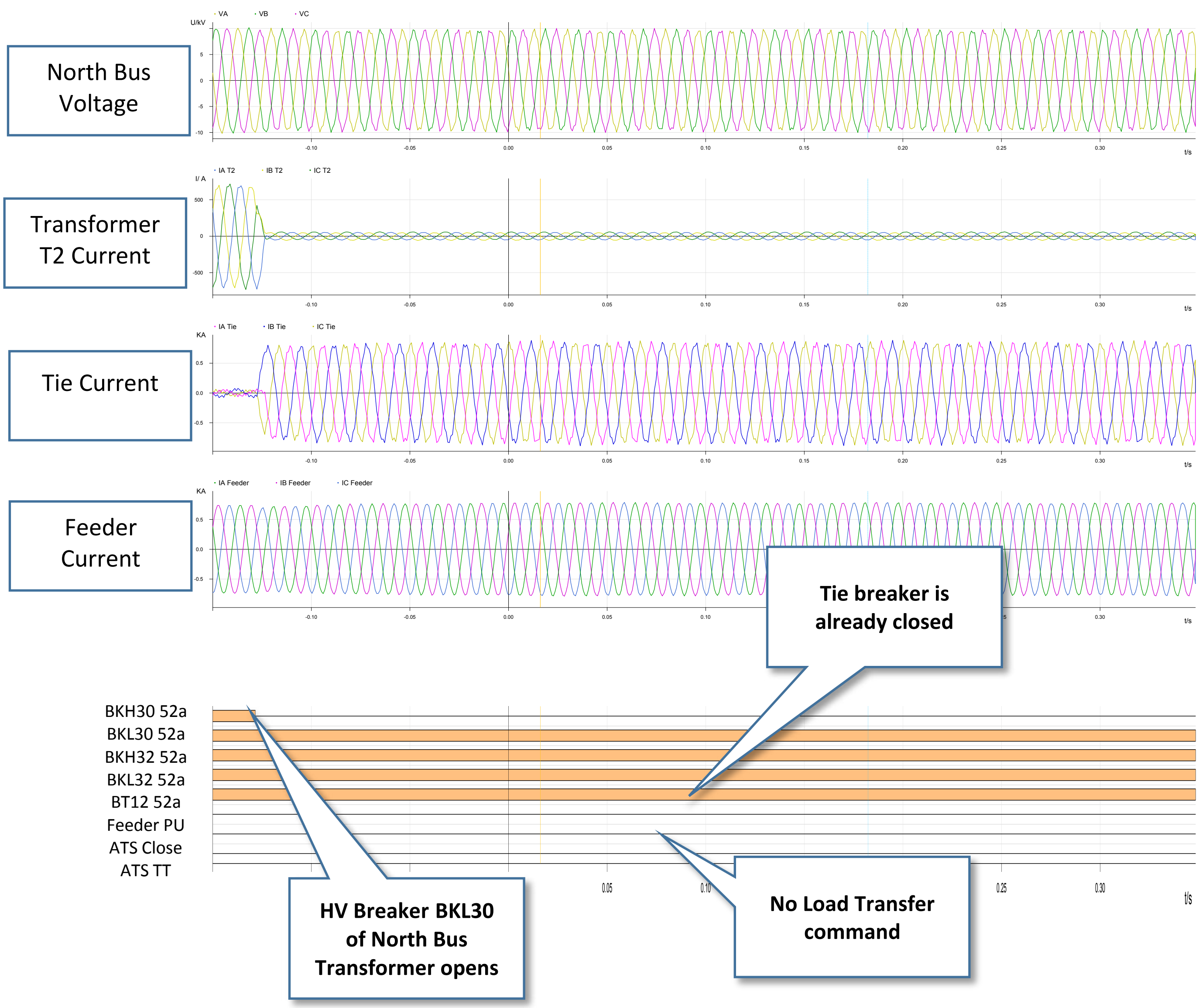
D.3.3 Test Case 3: South bus is de-energized when north bus transformer breaker opens

Case	Test Case	Description	Results IEC 61850 Design
3	South Bus is de-energized when North Bus transformer breaker opens	• South Bus High Side breaker BKH32 is open, all other transformer breakers (BKH30, BKL30BKL32) closed, and only North Bus is energized • Disconnect source by opening MV breaker of North Bus transformer T2 (BKL30) • Automatic transfer scheme is not started • Check correct operation	Scheme did not initiate a load transfer (correct operation)



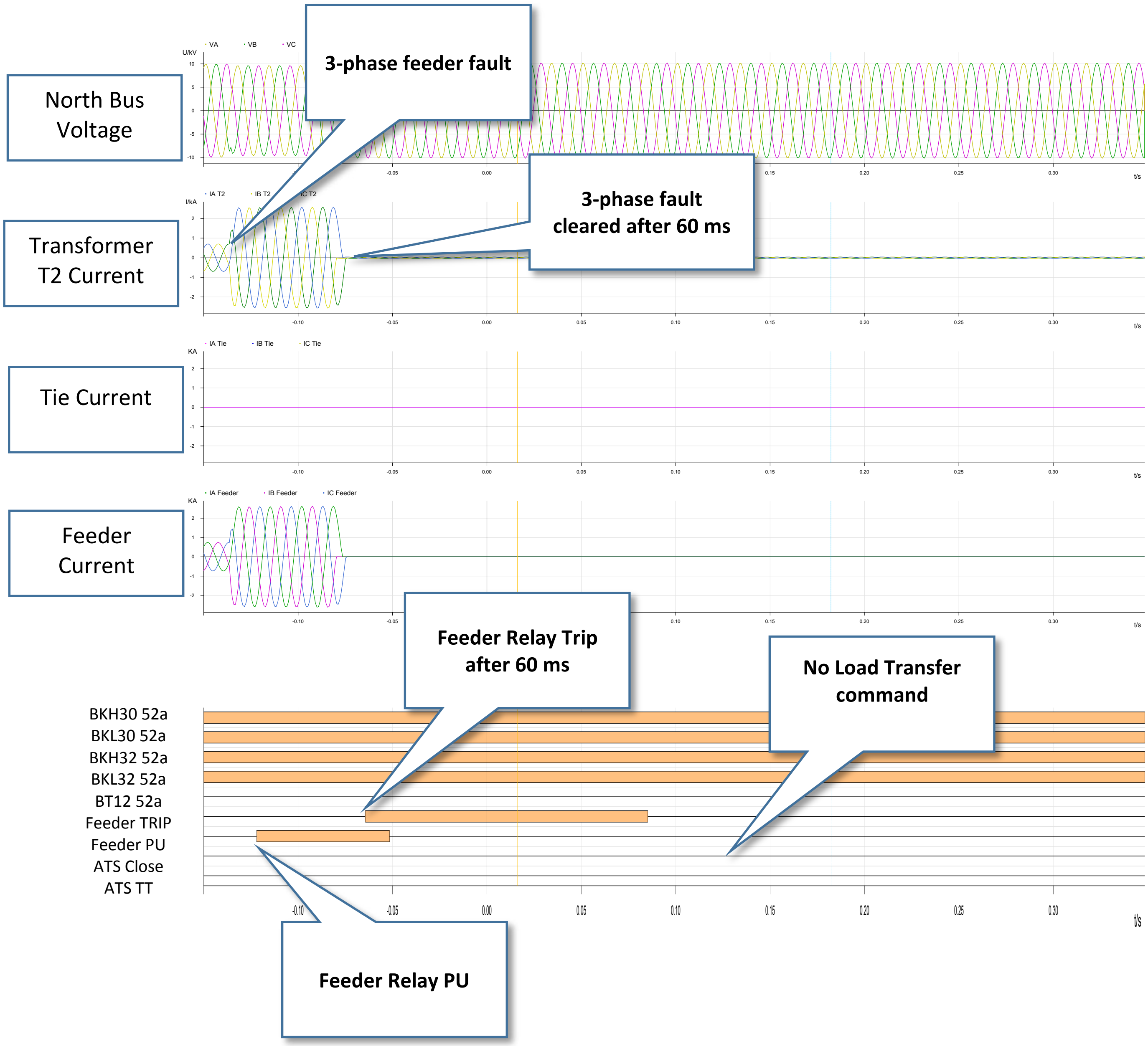
D.3.4 Test Case 4: Tie breaker is already closed when north bus transformer breaker opens

Case	Test Case	Description	Results IEC 61850 Design
4	Tie breaker is already closed when HV North Bus breaker opens	• All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized • Tie breaker (BT12) is closed • Disconnect source by opening HV breaker of North Bus transformer T2 (BKH30) • Automatic transfer scheme is started • Check correct operation	Scheme did not initiate a load transfer (correct operation)



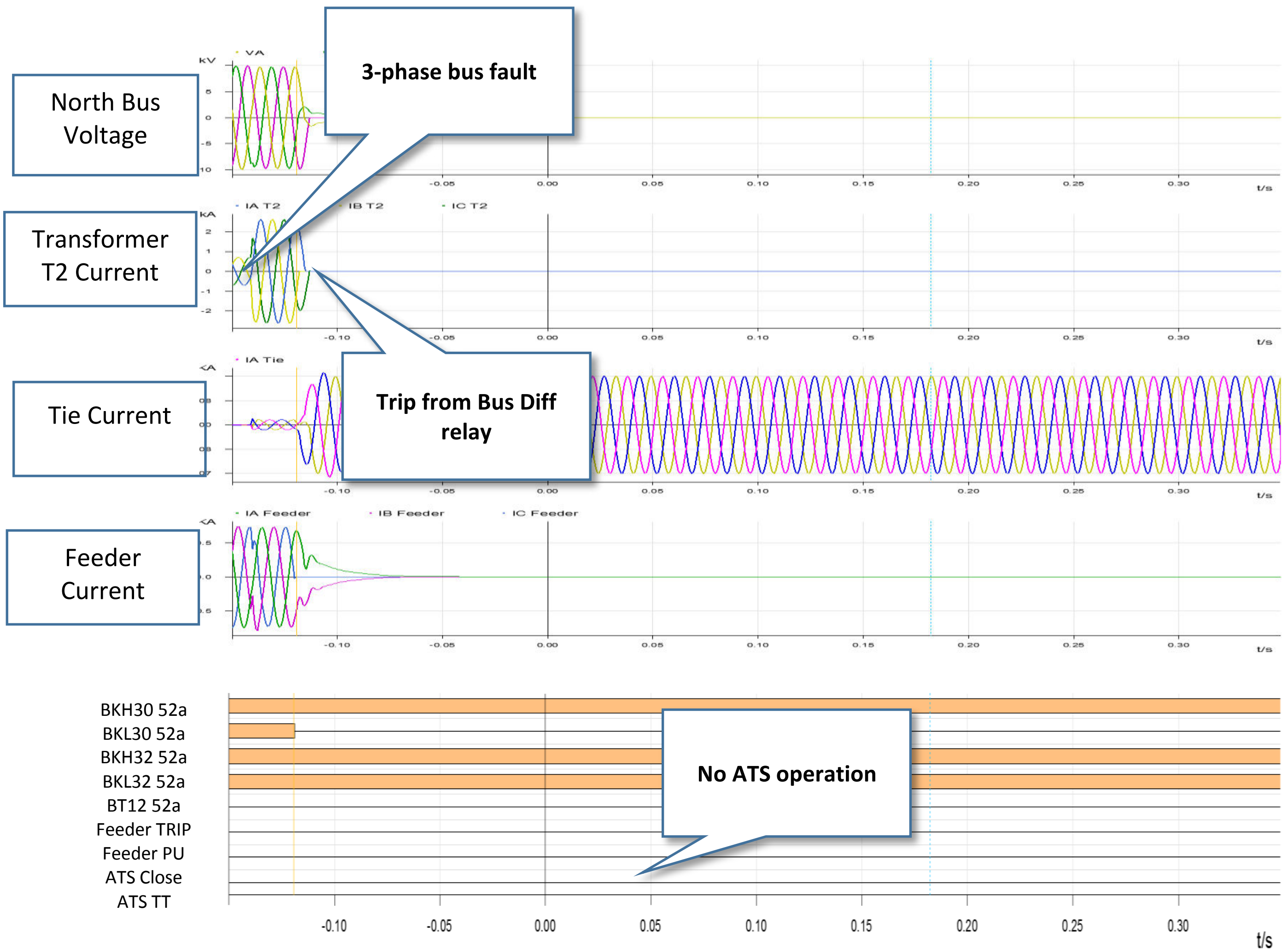
D.3.5 Test Case 5: Close-in feeder fault

Case	Test Case	Description	Results IEC 61850 Design
5	Close-In feeder fault	• All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized • Apply close-in feeder fault (on Bus 301) • Automatic transfer scheme is not started • Check correct operation	Scheme did not initiate a load transfer (correct operation)



D.3.6 Test Case 6: North bus de-energization after bus fault

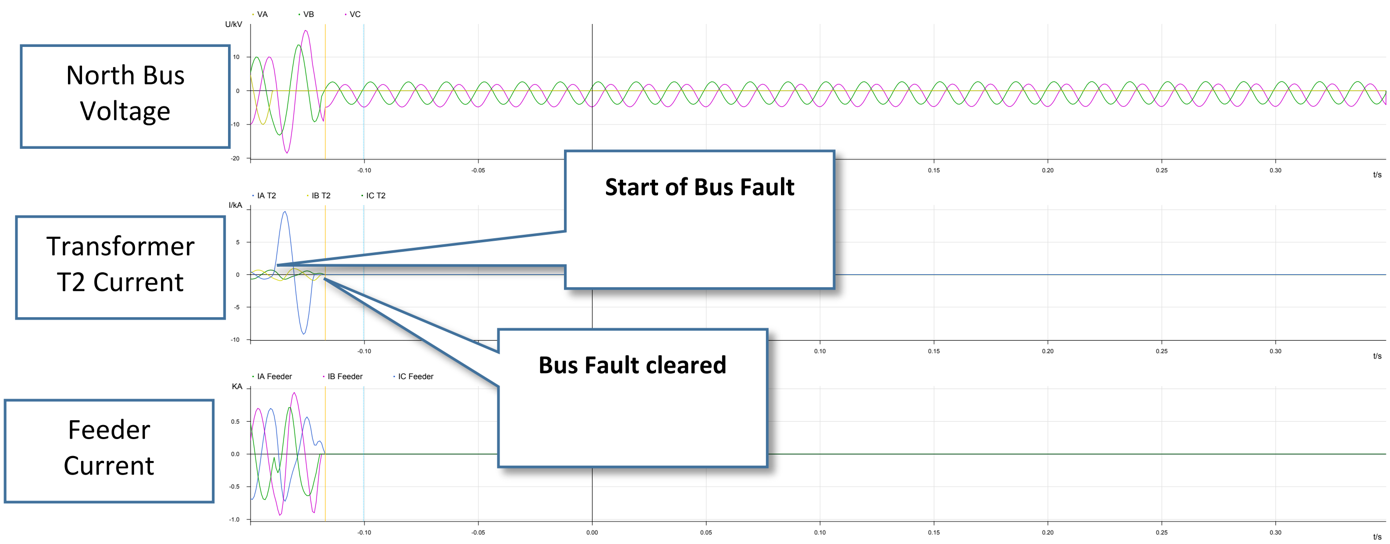
Case	Test Case	Description	Results IEC 61850 Design
6	North Bus de-energization after Bus Fault	• All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized • Apply 3-phase fault on North Bus • Automatic transfer scheme is not started • Check correct operation	Scheme did not initiate a load transfer (correct operation)

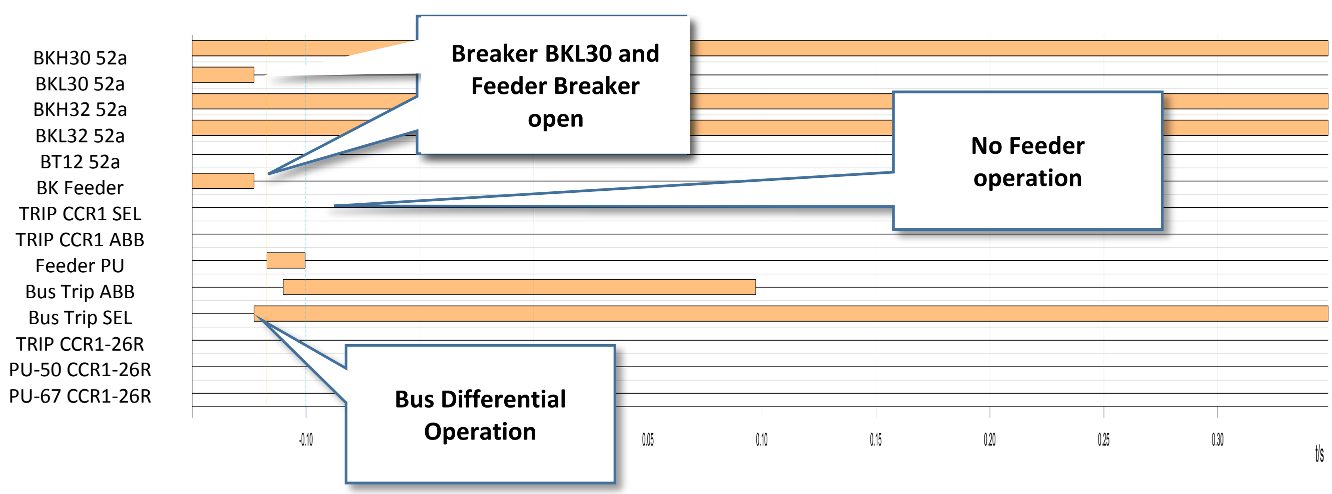


D.4 Use Case 5: Improved protection coordination

D.4.1 Test Case 1: Scheme response for bus fault

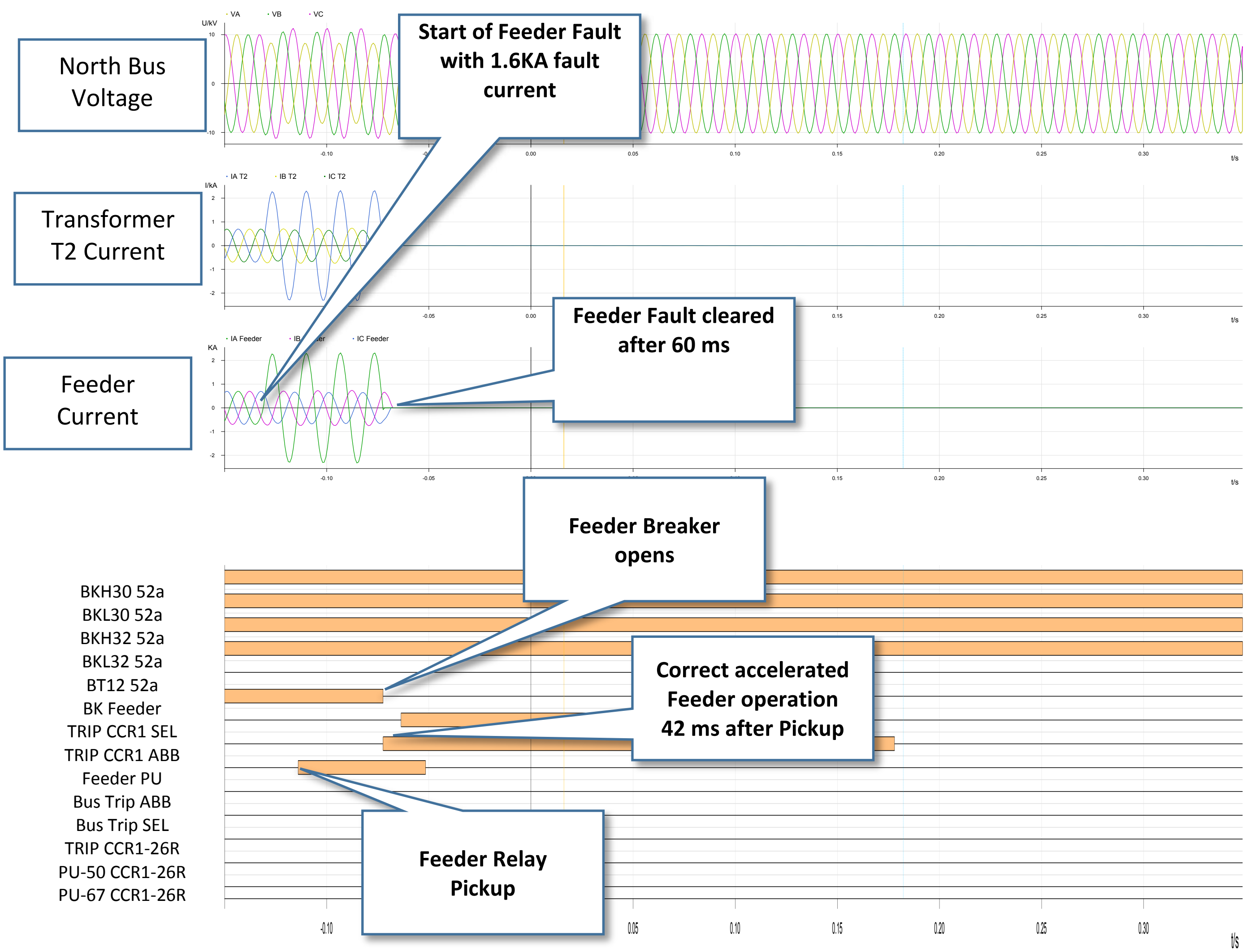
Test #	Test case	Description	Results Conventional Design	Results IEC 61850 Design
1	Substation bus fault	• South Bus and North Bus energized and all feeder breakers closed • Inject A-G Fault on North Bus • Bus protection trips all bus breakers	Instantaneous bus fault clearing by bus differential relay	Instantaneous bus fault clearing by bus differential relay





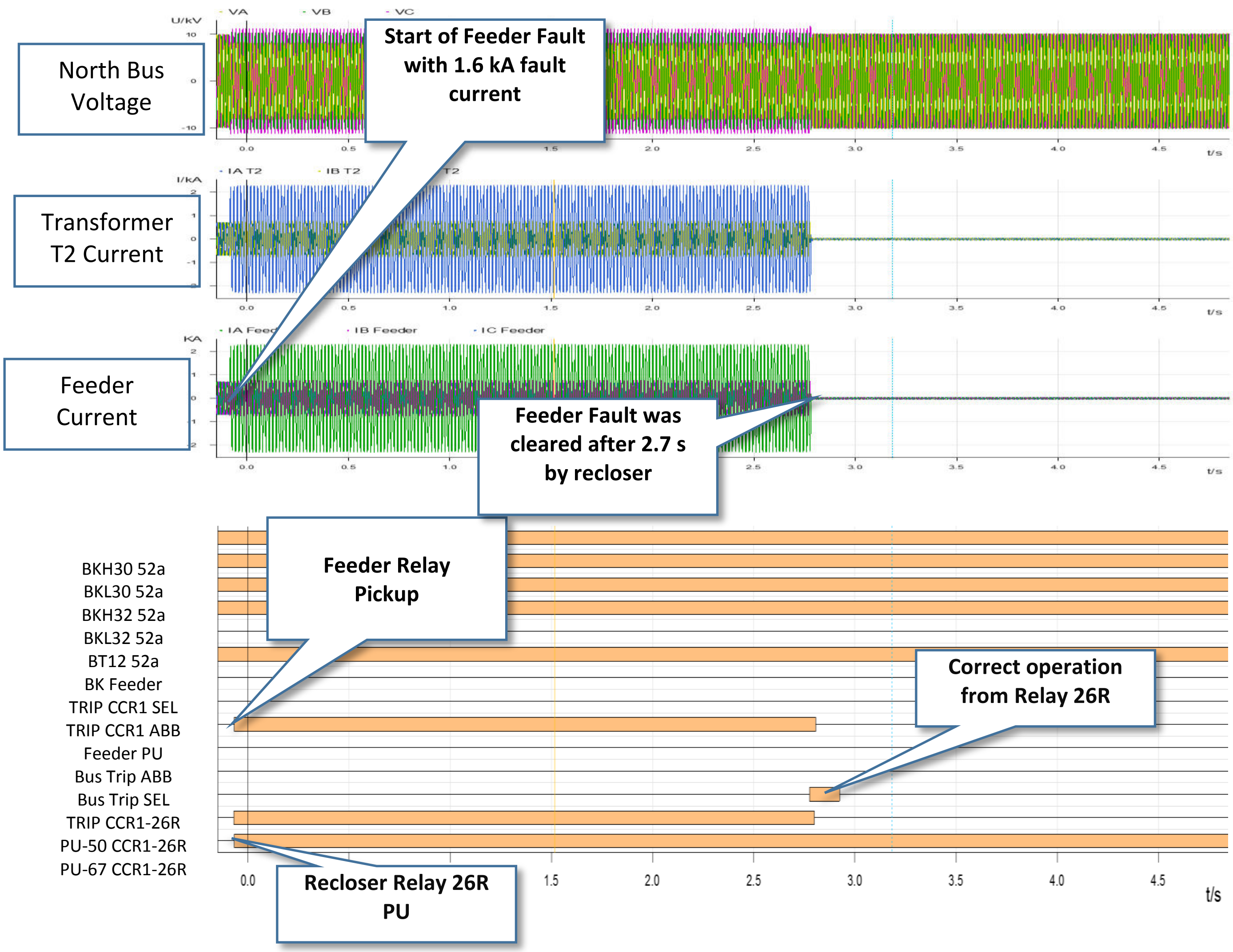
D.4.2 Test Case 2: Scheme response for close-in feeder fault

Test #	Test case	Description	Results Conventional Design	Results IEC 61850 Design
2	Close-In Feeder Fault	• North Bus is energized and target feeder is connected • Inject a A-G Close-In Feeder Fault (on Bus 301) with 5 Ohm • Feeder relay issues an instantaneous trip as it will not receive blocking signal from remote recloser	Element 51 in the feeder relay cleared the fault after 1.5 s due to 1.6 kA fault current	Fast fault clearing after 60 ms by advanced protection scheme



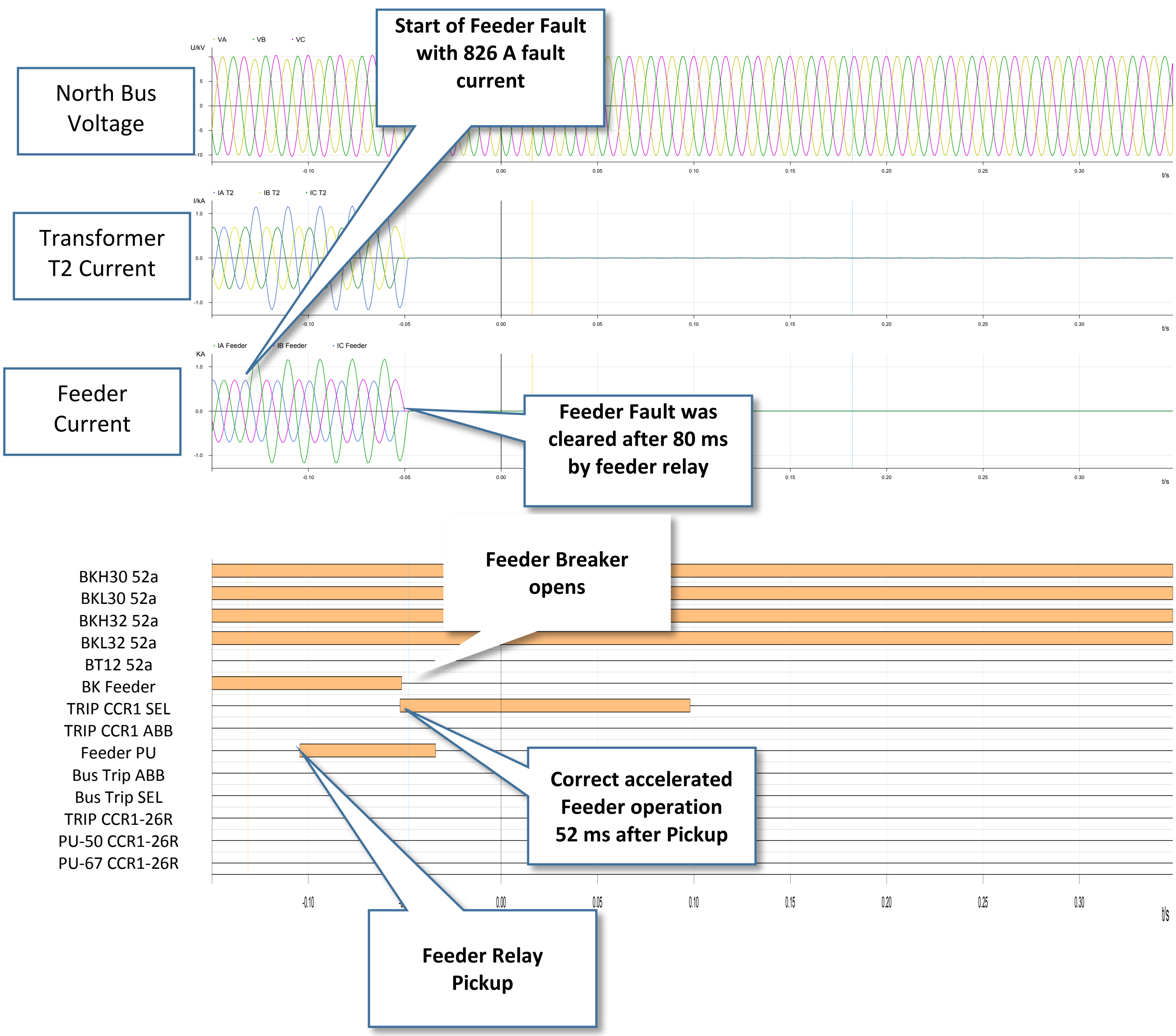
D.4.3 Test Case 3: Scheme response for feeder fault behind next recloser

Test #	Test case	Description	Results Conventional Design	Results IEC 61850 Design
3	Feeder Fault behind next Recloser	• North Bus is energized and target feeder is connected • Inject a A-G Feeder Fault (on Bus 302) with 5 Ohm • Recloser will trip fault and block CCR2 relay in Substation	Element 51 in the 26R recloser cleared fault after 1.2s due to 1.6 kA fault current	Element 51 in the 26R recloser cleared fault after 1.2 s due to 1.6 kA fault current



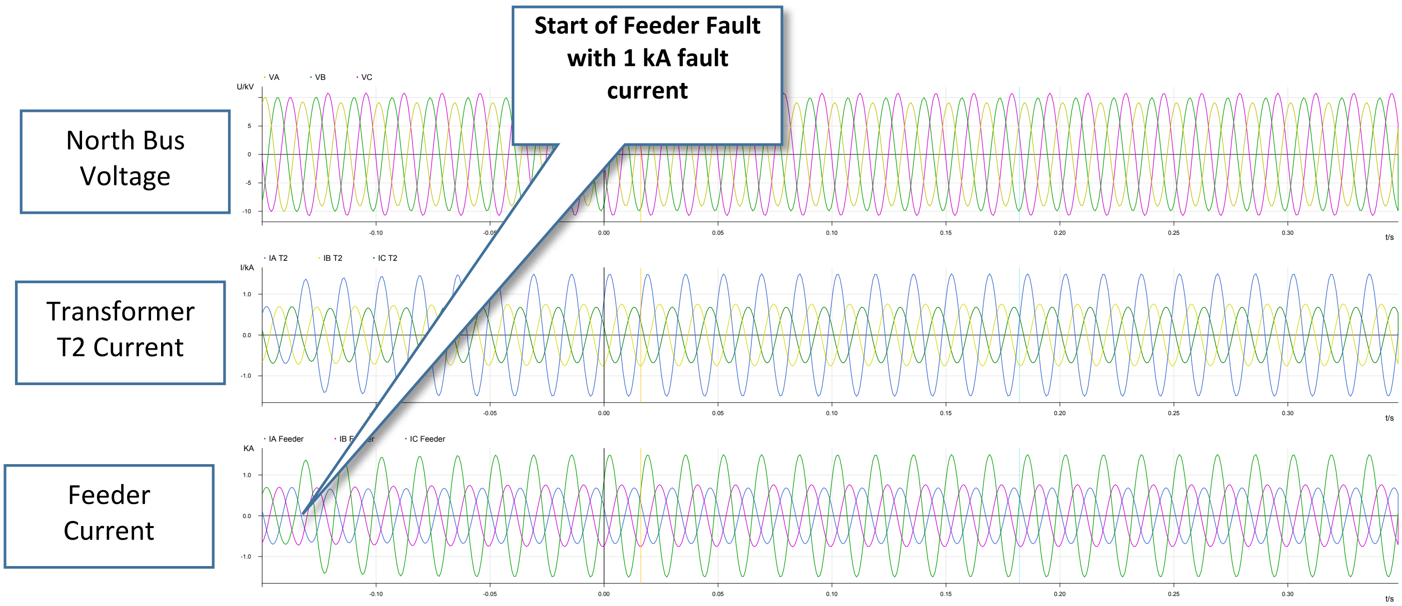
D.4.4 Test Case 4: High resistive close-in feeder fault

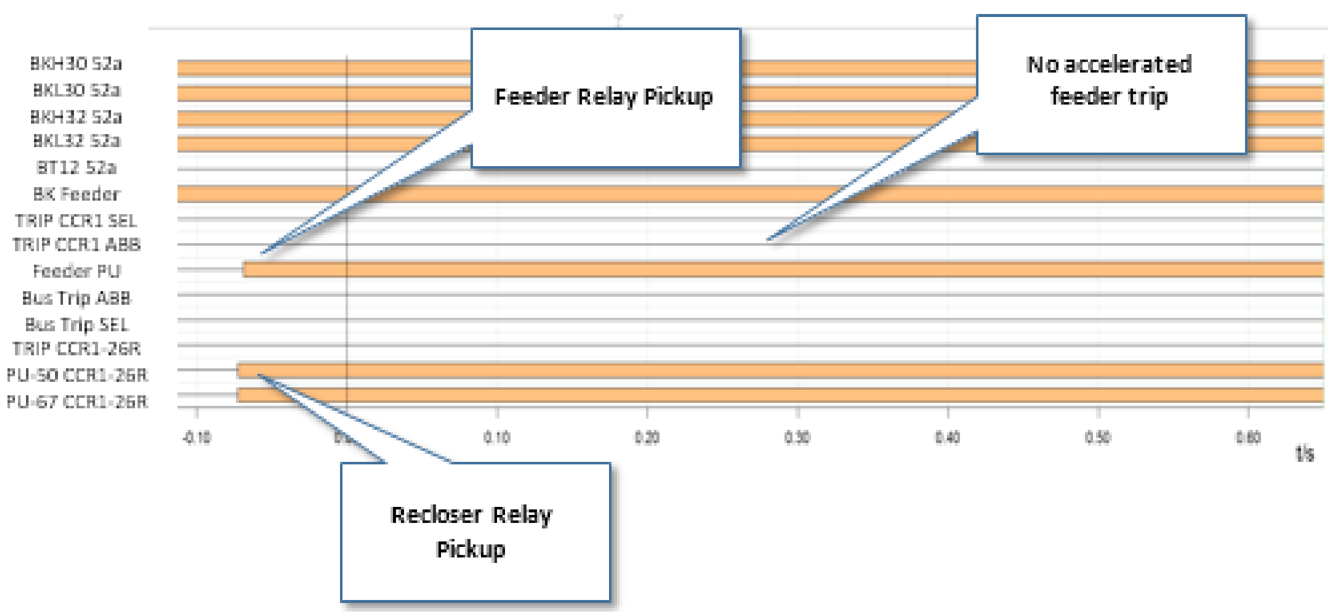
Test #	Test case	Description	Results Conventional Design	Results IEC 61850 Design
4	High Resistive Close-In Feeder Fault	• North Bus is energized and target feeder is connected • Inject a A-G Close-In Feeder Fault (on Bus 301) with 20 Ohm • Feeder relay issues an instantaneously trip as it will not receive blocking signal from remote recloser	Element 51 in the feeder relay cleared the fault after 3.5s due to 830 A fault current	Fast fault clearing after 80 ms by advanced protection scheme



D.4.5 Test Case 5: Feeder end-of-line fault

Test #	Test case	Description	Results Conventional Design	Results IEC 61850 Design
5	Feeder End-of-Line Fault	• North Bus is energized and target feeder is connected • Inject a A-G Feeder End-of-Line Fault (on Bus 305) • Recloser 32R will trip fault	Fault cleared by 32R recloser after 1.2 s based on fault current	Fault cleared by 32R recloser after 1.2 s based on fault current





D.5 Use Case 6: DER control test results

D.5.1 PV 2 Results (SMA Inverter)

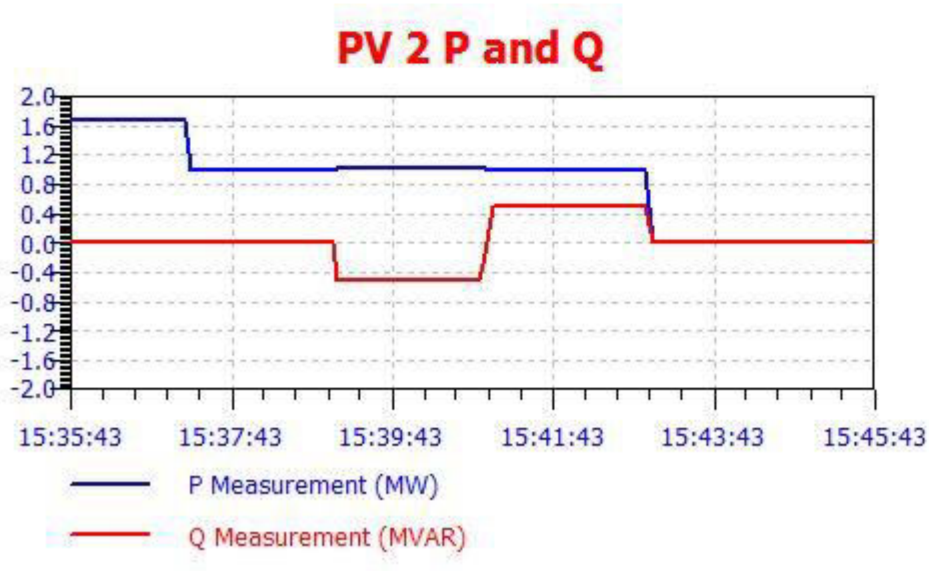


Figure D-30. Reponses of the SMA inverter in Control Mode 1

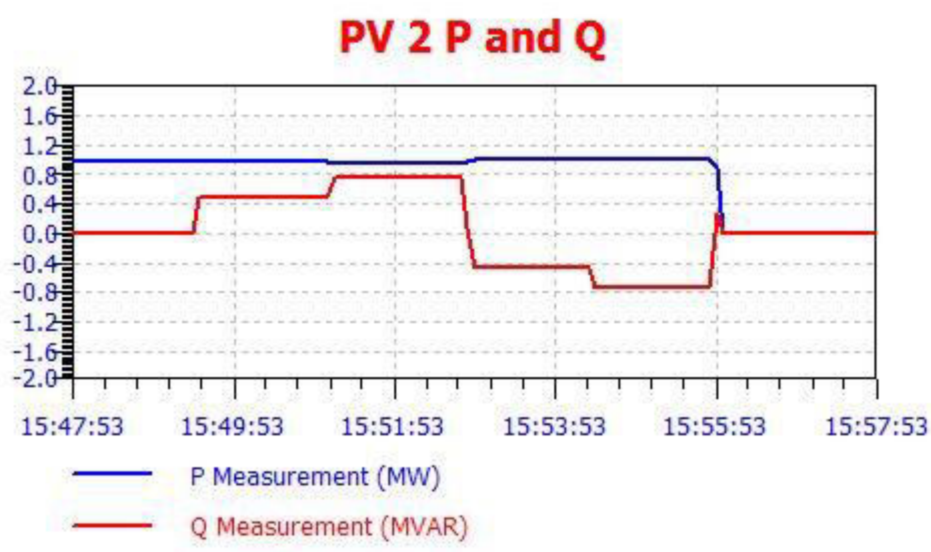


Figure D-31. Reponses of the SMA inverter in Control Mode 2

D.5.2 BESS 2 Results (Simulated)

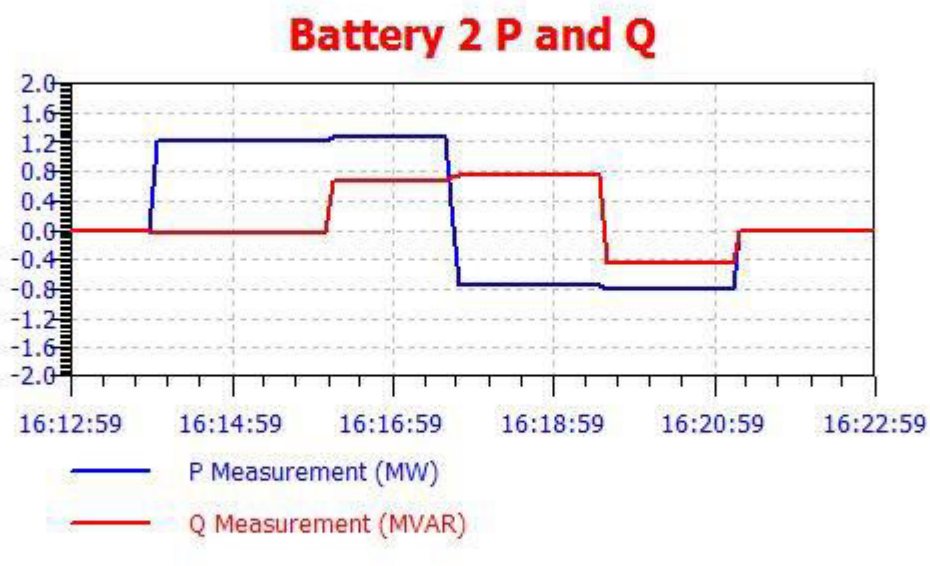


Figure D-32. Response of BESS 2 in Control Mode 1

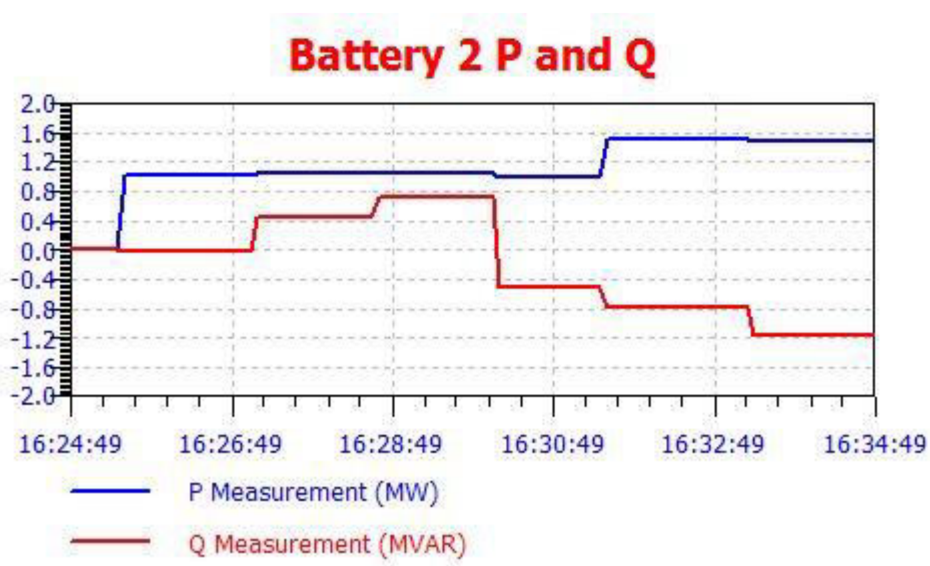


Figure D-33. Response of BESS 2 in Control Mode 2

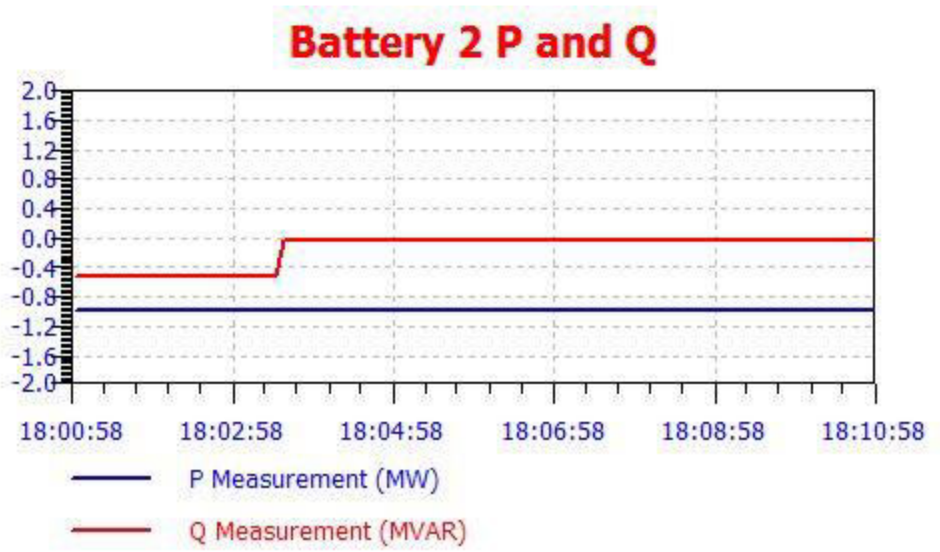


Figure D-34. Response of BESS 2 in Control Mode 3 (output power)

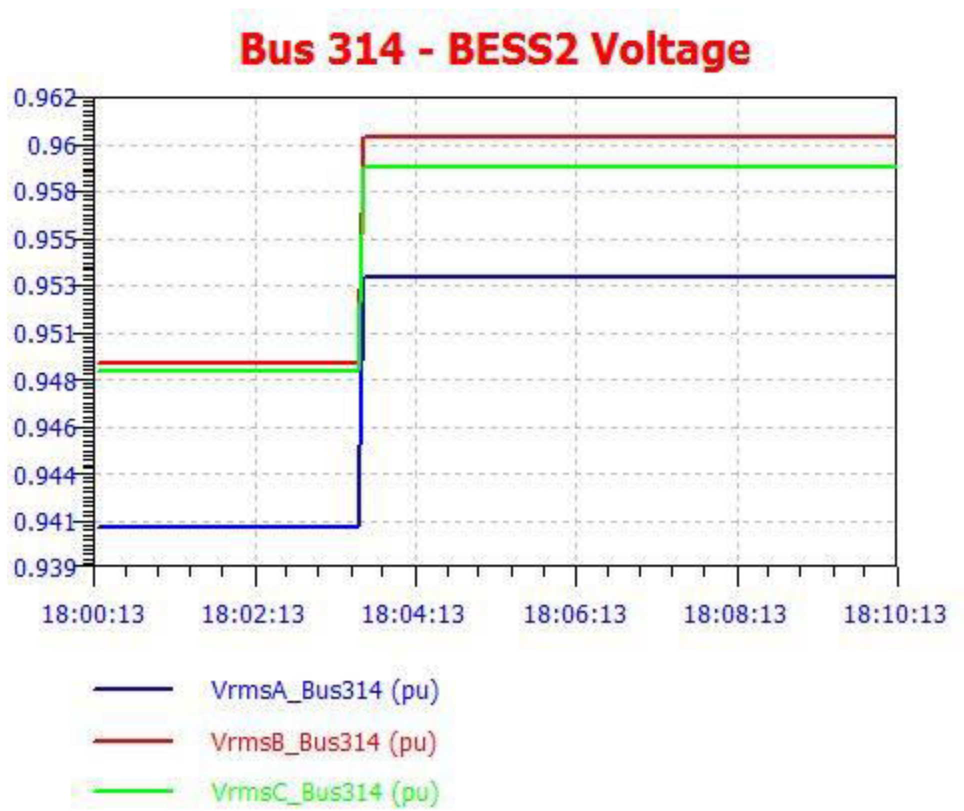


Figure D-35. Response of BESS 2 in Control Mode 1 (terminal voltage)

D.6 Use Case 7: Grid support using DERs

D.6.1 Test Case 7.1 Results

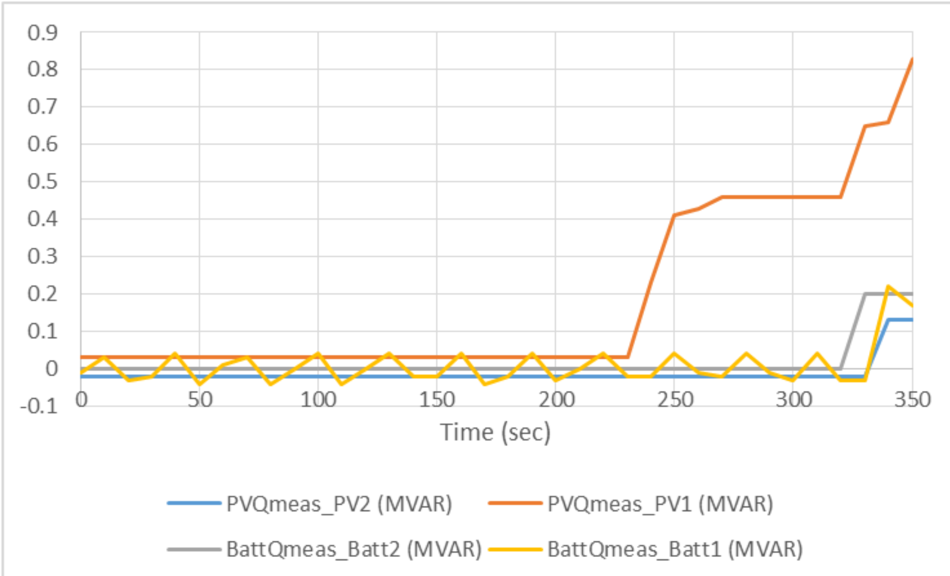


Figure D-36. DER reactive power measurements (Mvar)

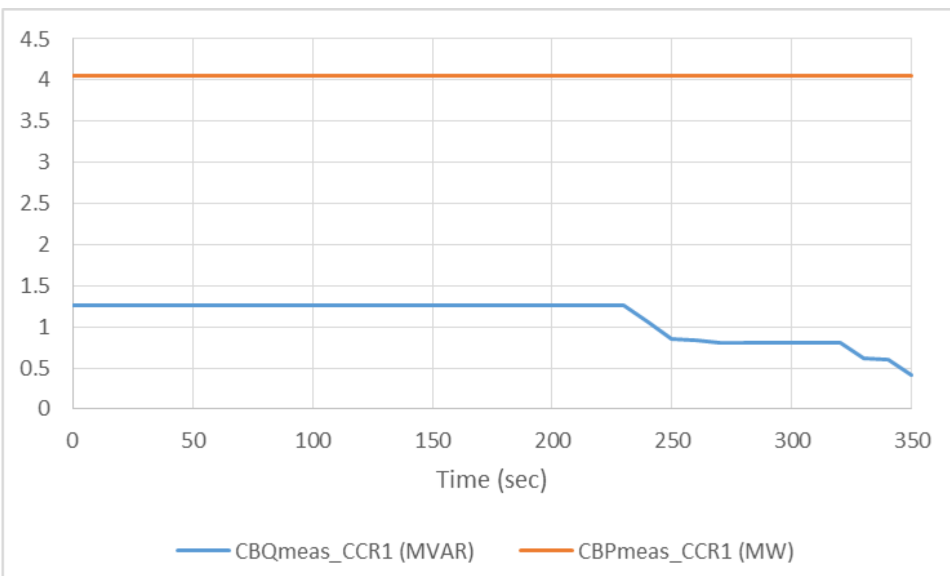


Figure D-37. CCR1 power flow measurement (MW & Mvar)

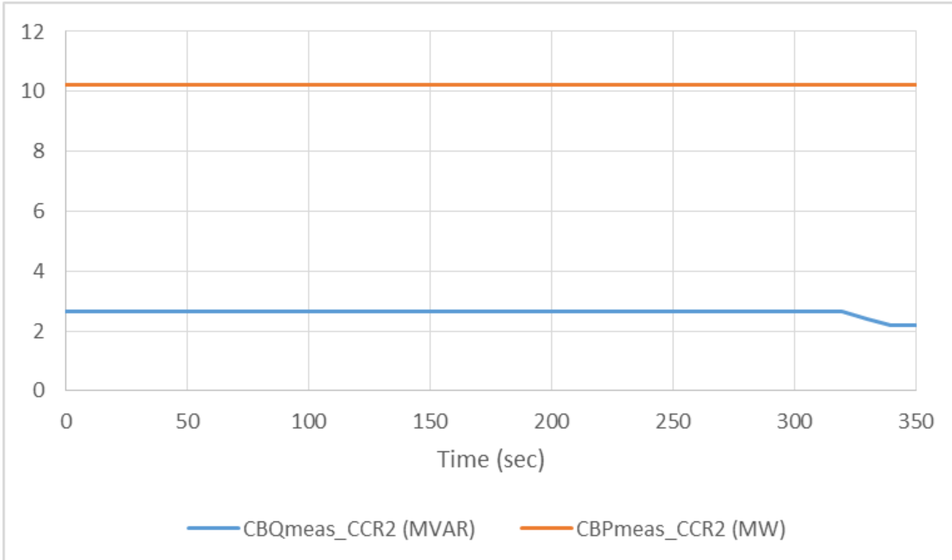


Figure D-38. CCR2 power flow measurement (MW & Mvar)

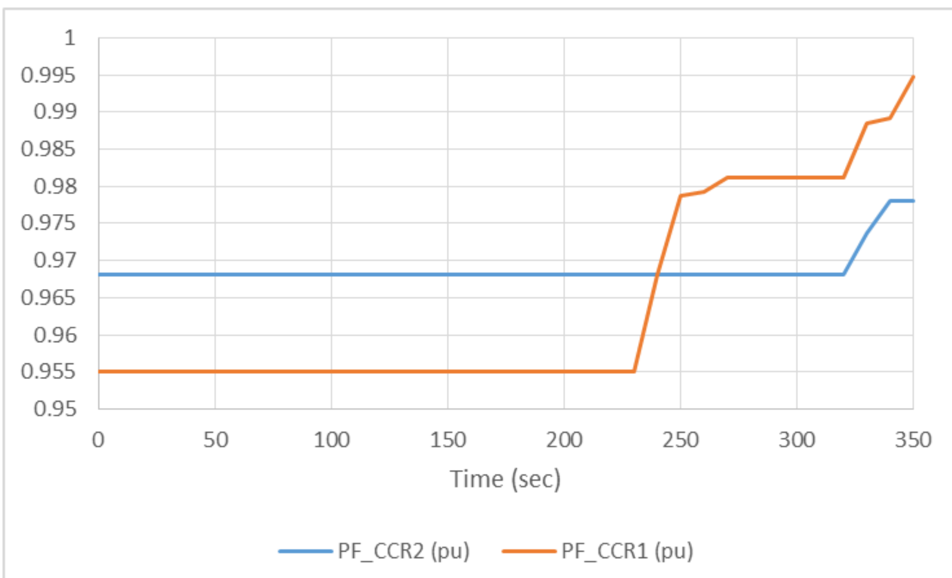


Figure D-39. CCR1 & CCR2 power factor measurement (pu)

D.6.2 Test Case 7.2 Results

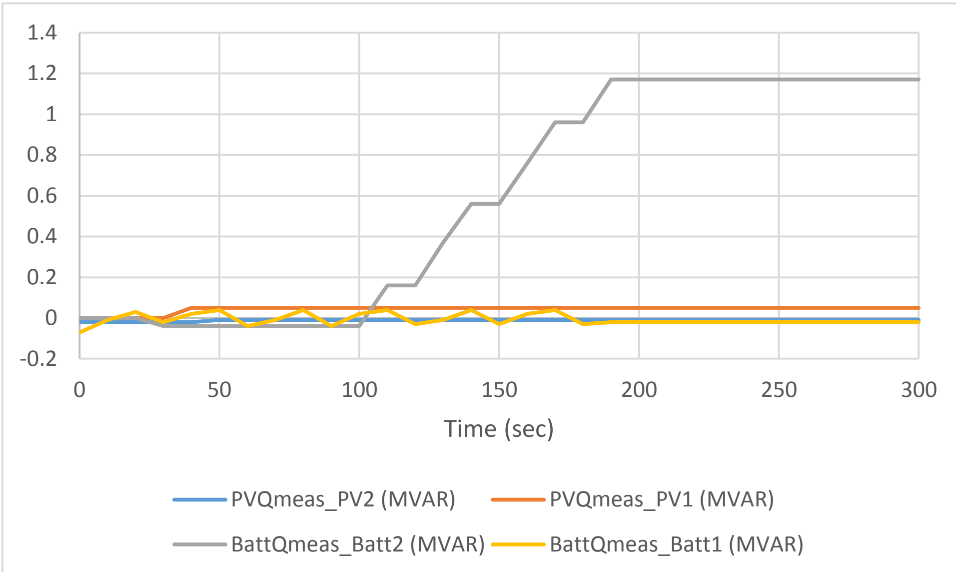


Figure D-40. DER reactive power measurements (Mvar)

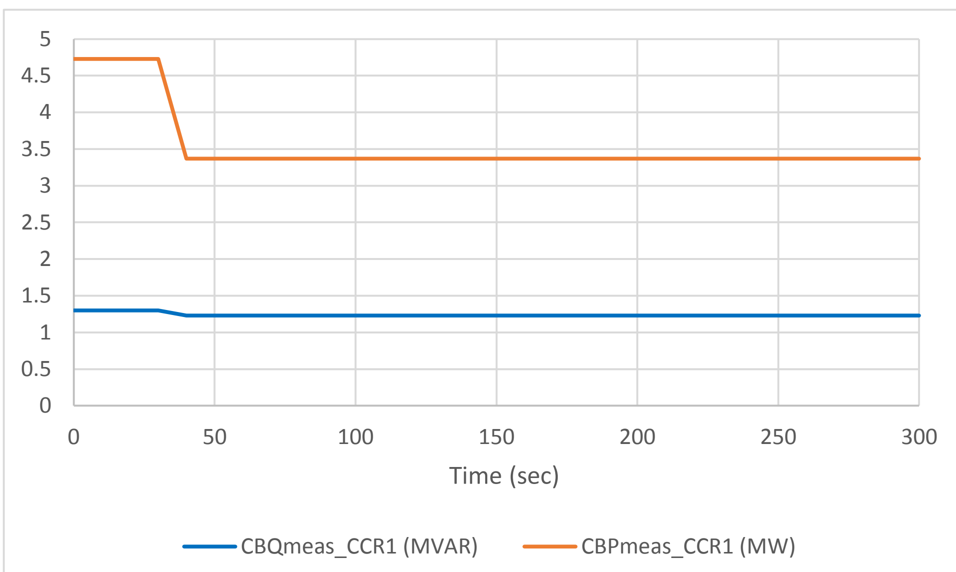


Figure D-41. CCR1 power flow measurement (MW & Mvar)

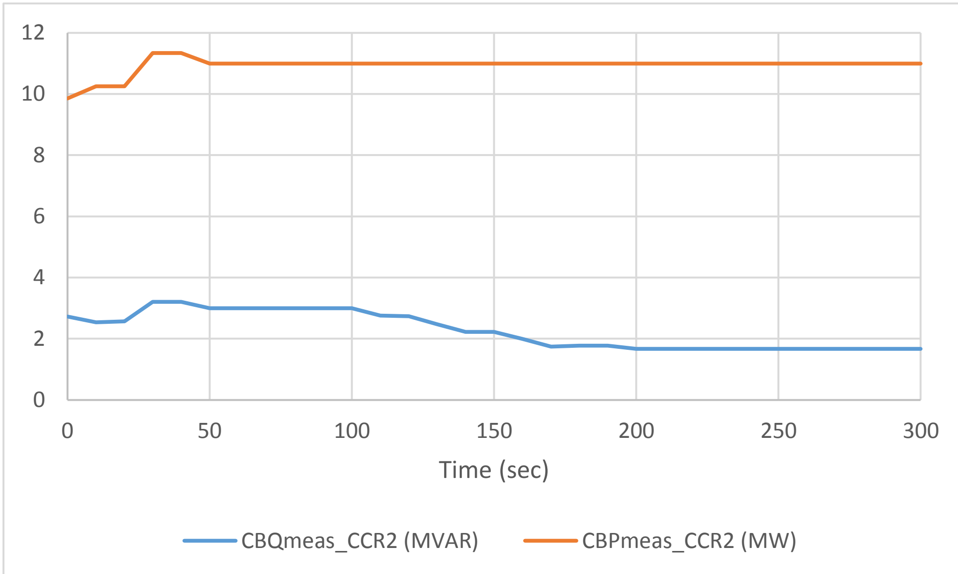


Figure D-42. CCR2 power flow measurement (MW & Mvar)

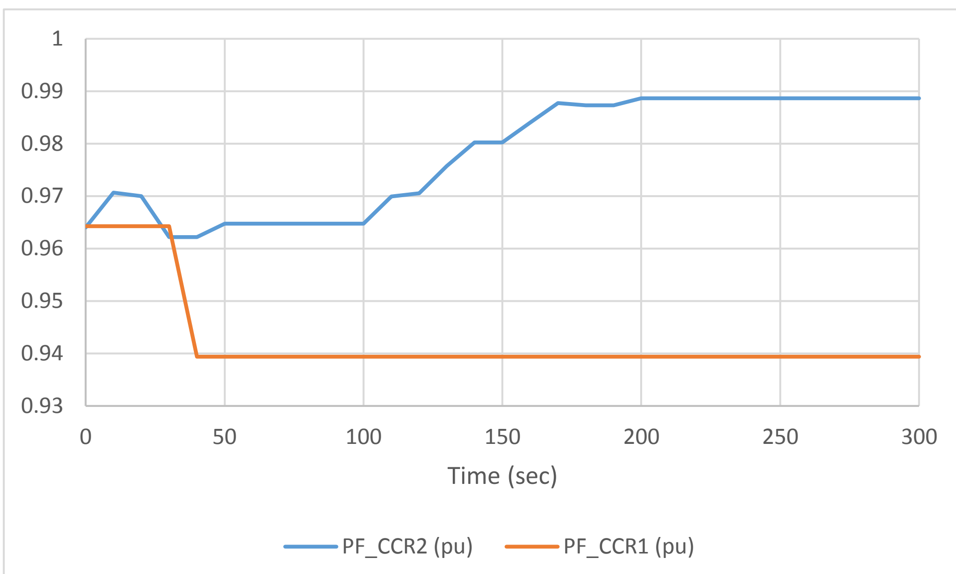


Figure D-43. CCR1 & CCR2 power factor measurement (pu)

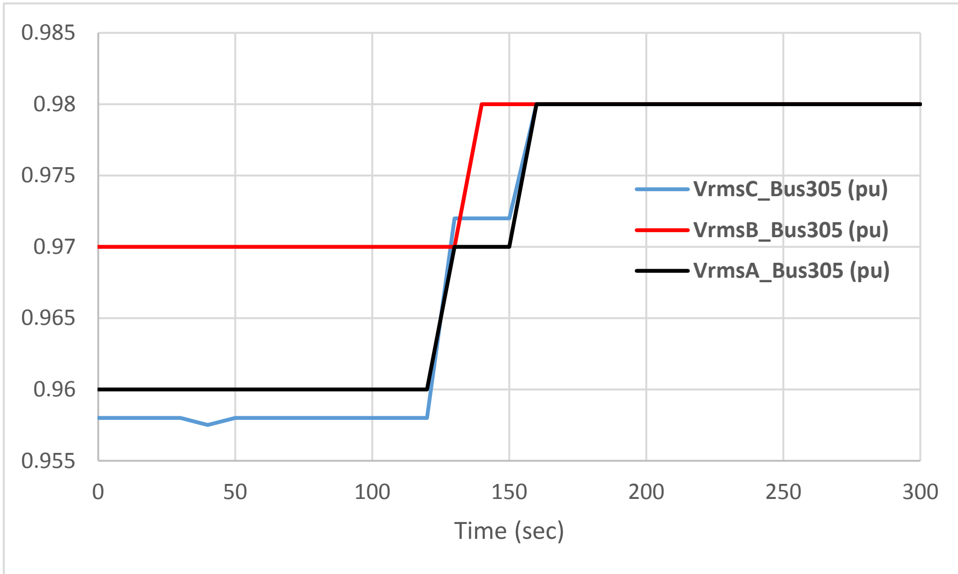


Figure D-44. RMS voltage at bus #305 (pu)

D.6.3 Test Case 7.3 Results

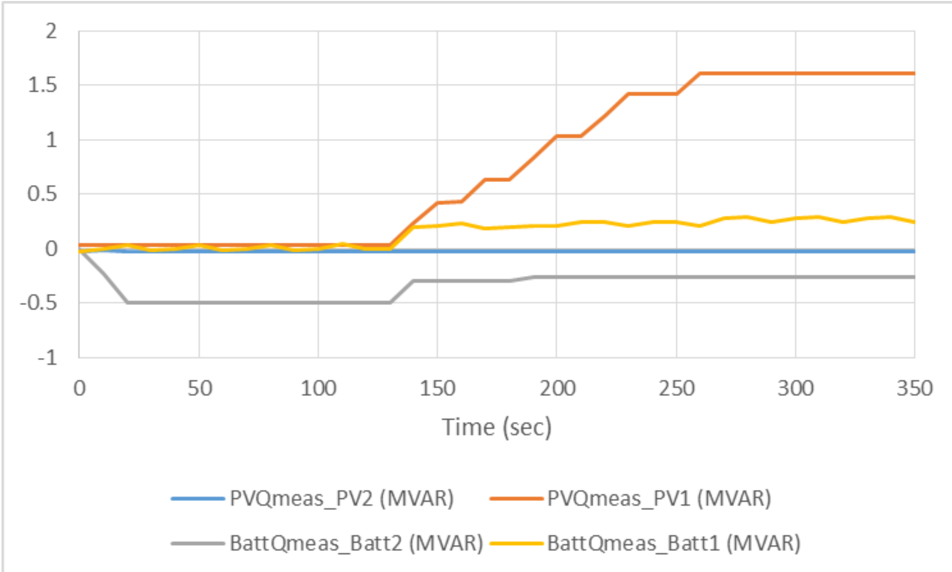


Figure D-45. DER reactive power measurements (Mvar)

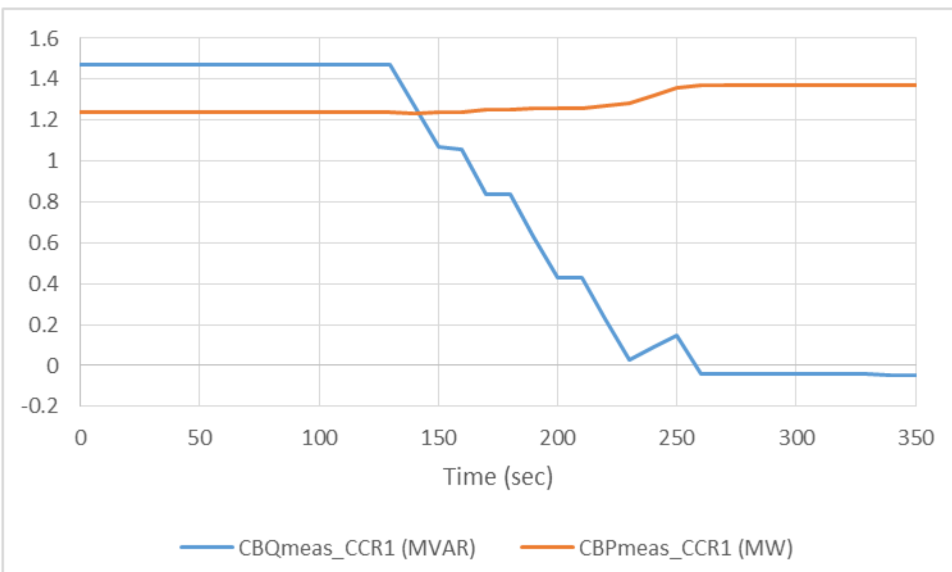


Figure D-46. CCR1 power flow measurement (MW & Mvar)

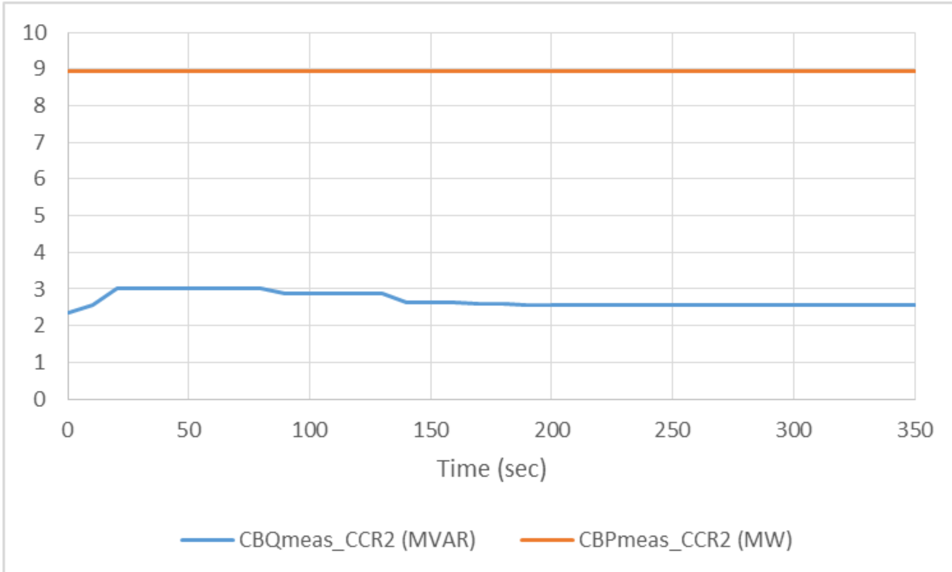


Figure D-47. CCR2 power flow measurement (MW & Mvar)

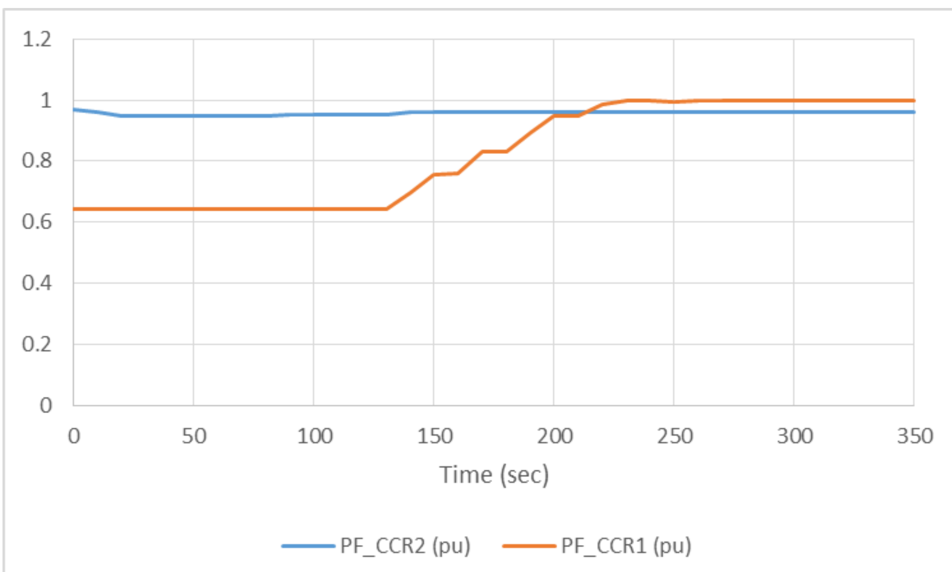


Figure D-48. CCR1 & CCR2 power factor measurement (pu)

D.6.4 Test Case 7.4 Results

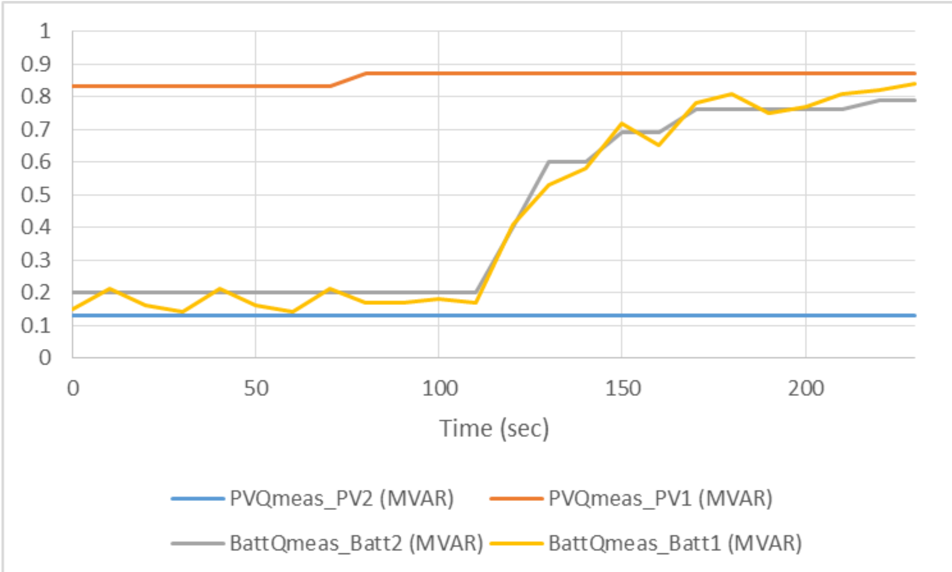


Figure D-49. DER reactive power measurements (Mvar)

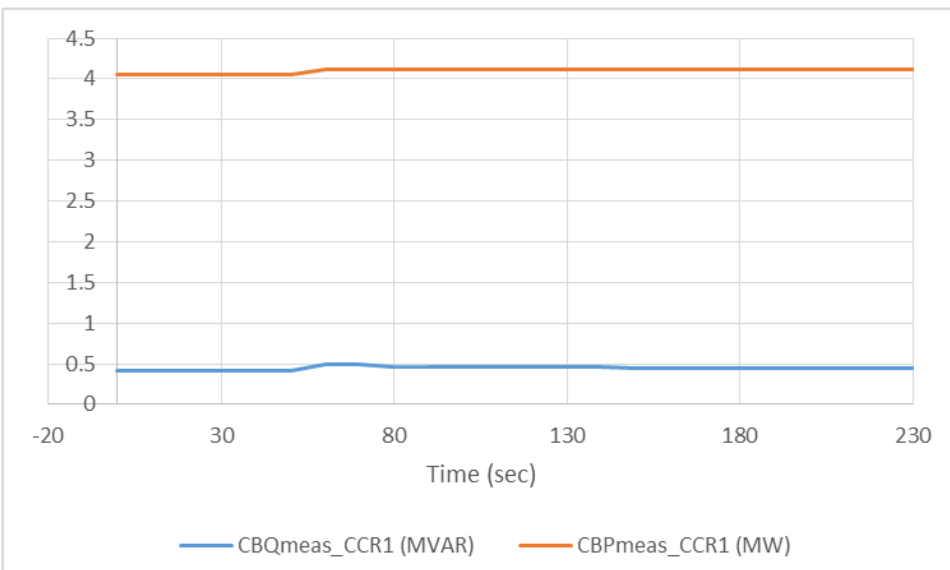


Figure D-50. CCR1 power flow measurement (MW & Mvar)

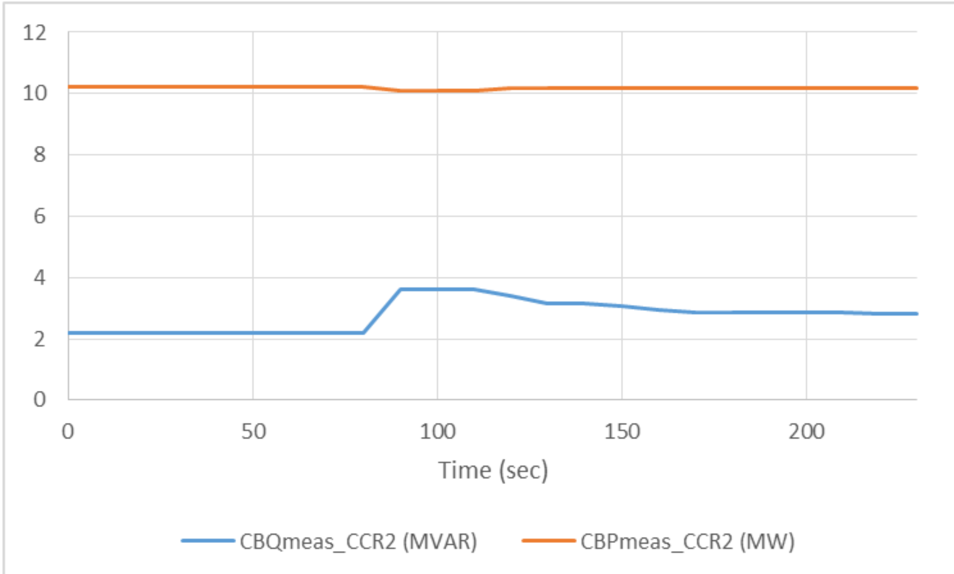


Figure D-51. CCR2 power flow measurement (MW & Mvar)

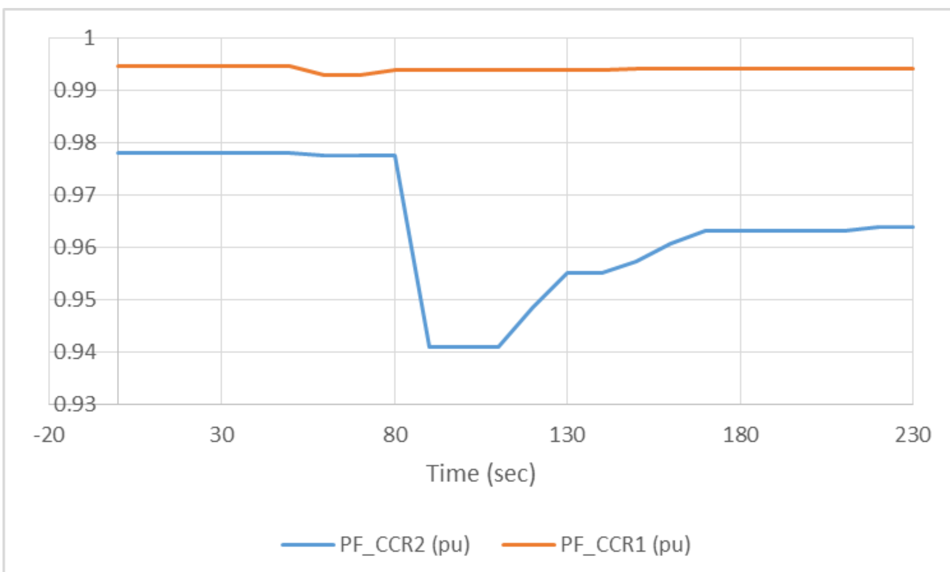


Figure D-52. CCR1 & CCR2 power factor measurement (pu)

D.6.5 Test Case 7.5 Results

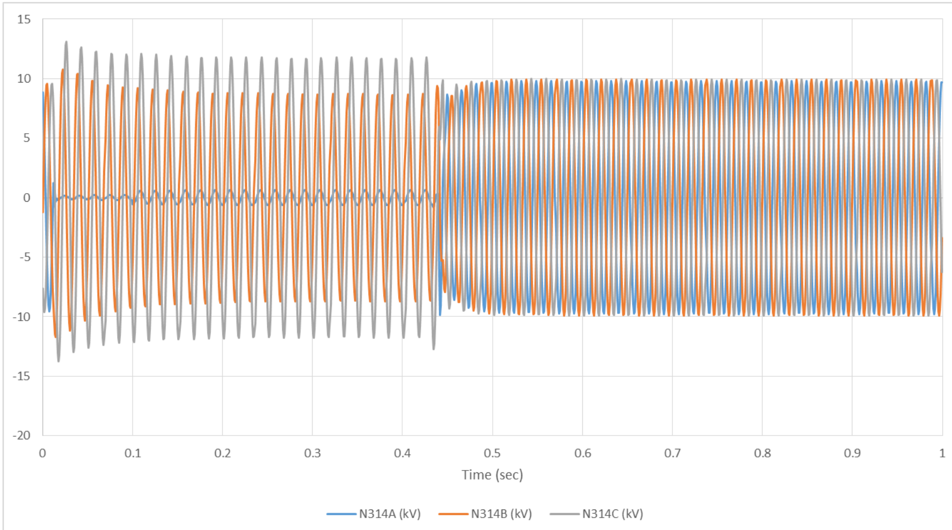


Figure D-53. Battery instantaneous voltage (kV) - High voltage side

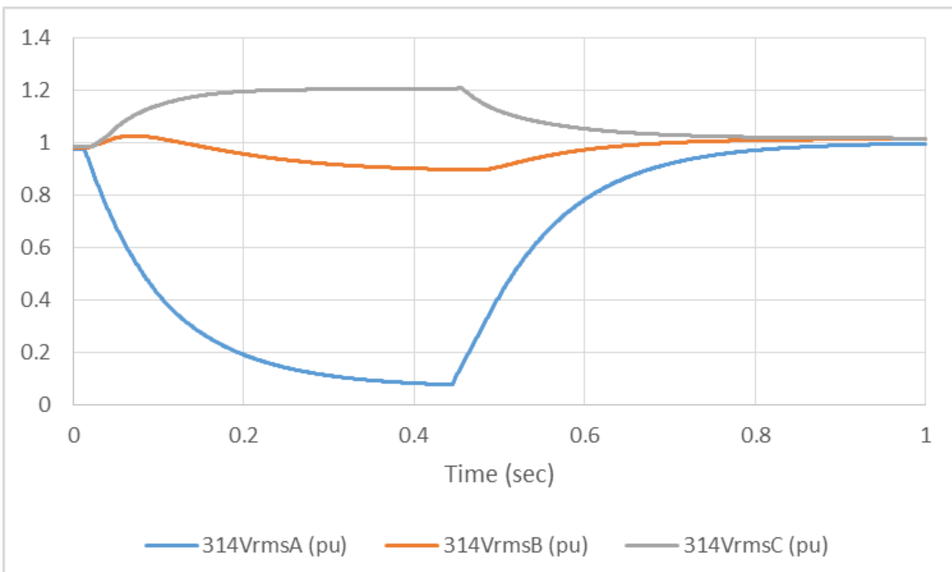


Figure D-54. Battery rms voltage (pu) - High voltage side

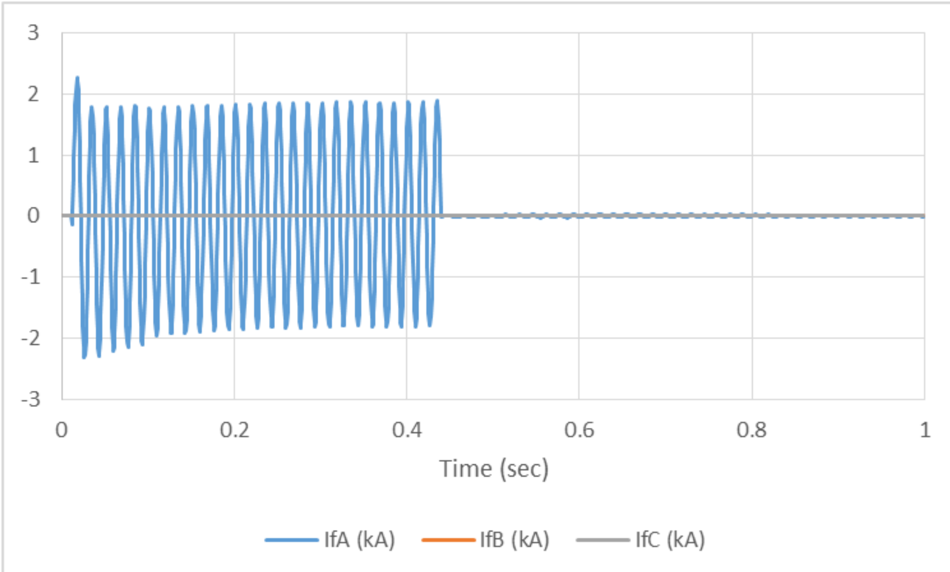


Figure D-55. Fault current at Bus #305 (kA)

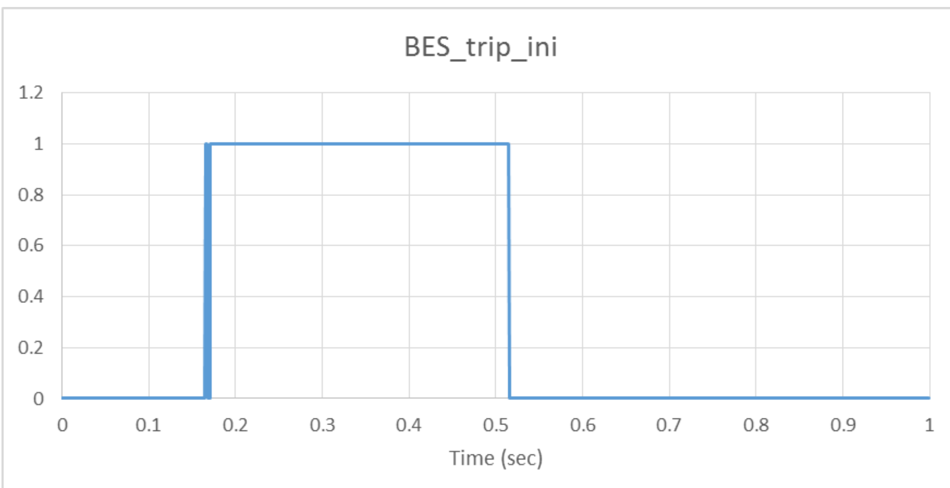


Figure D-56. Battery initial trip signal

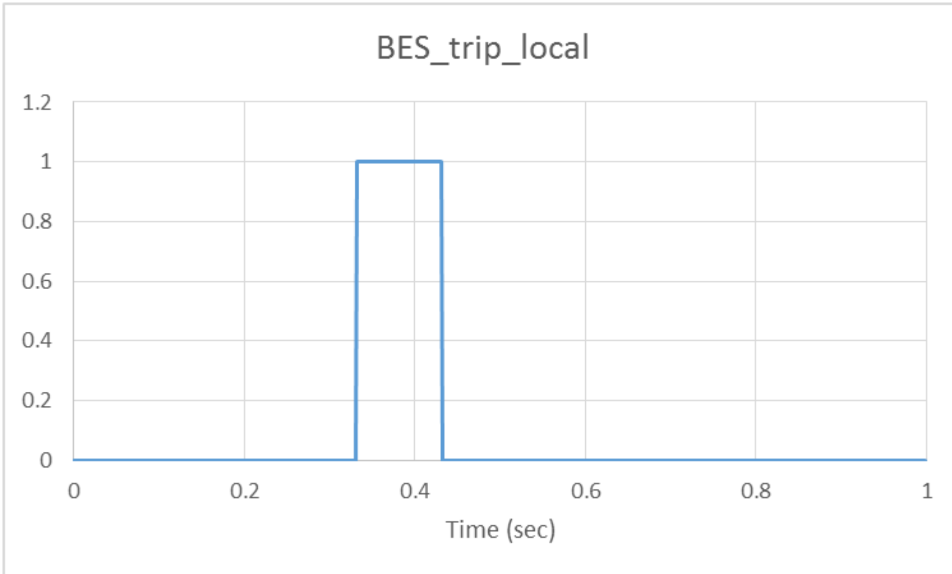


Figure D-57. Battery local trip signal

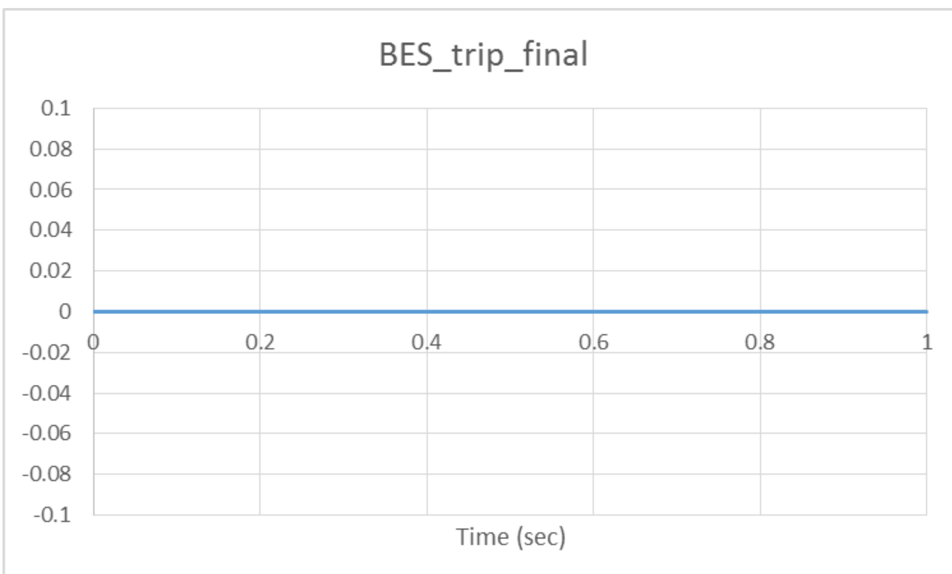


Figure D-58. Battery final trip signal

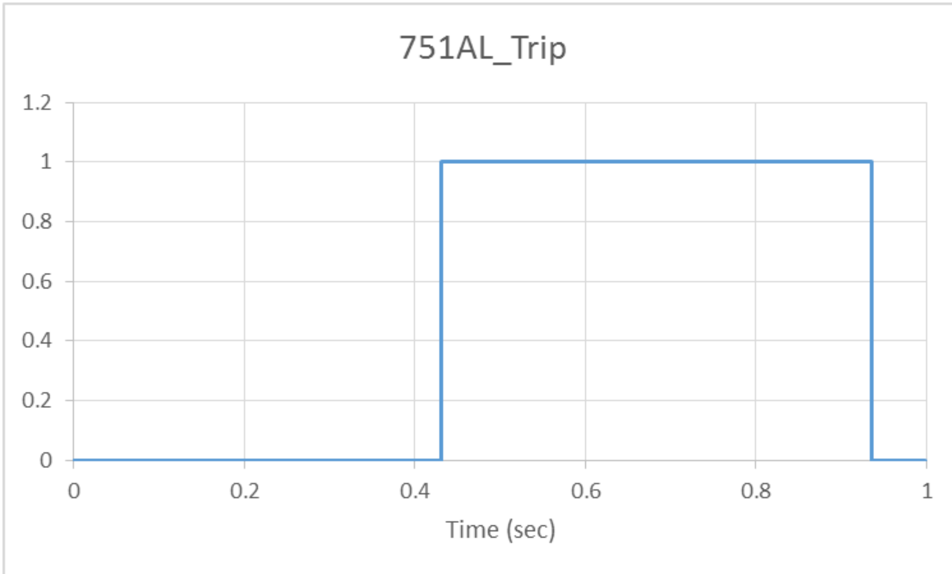


Figure D-59. 751 relay trip signal

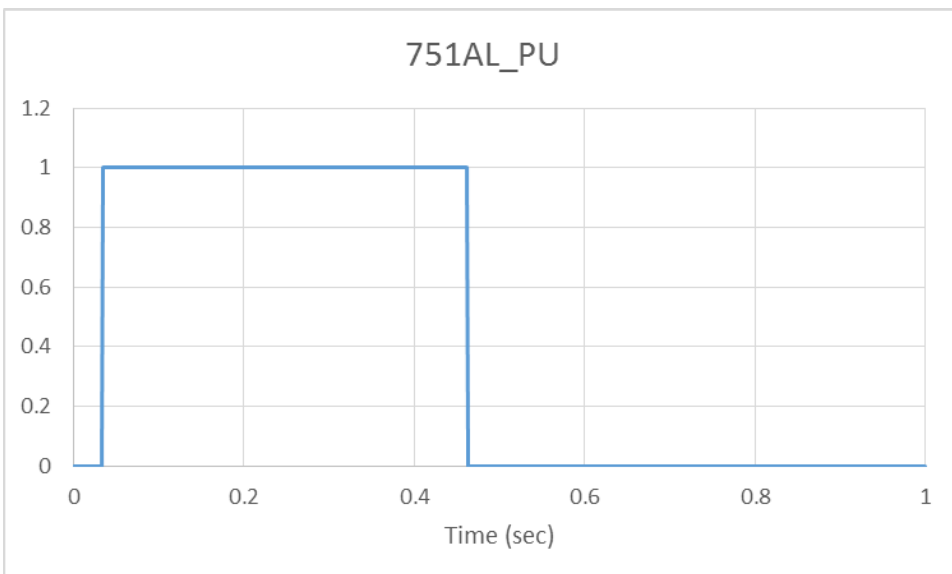


Figure D-60. 751 relay pickup signal

D.6.6 Test Case 7.6 Results

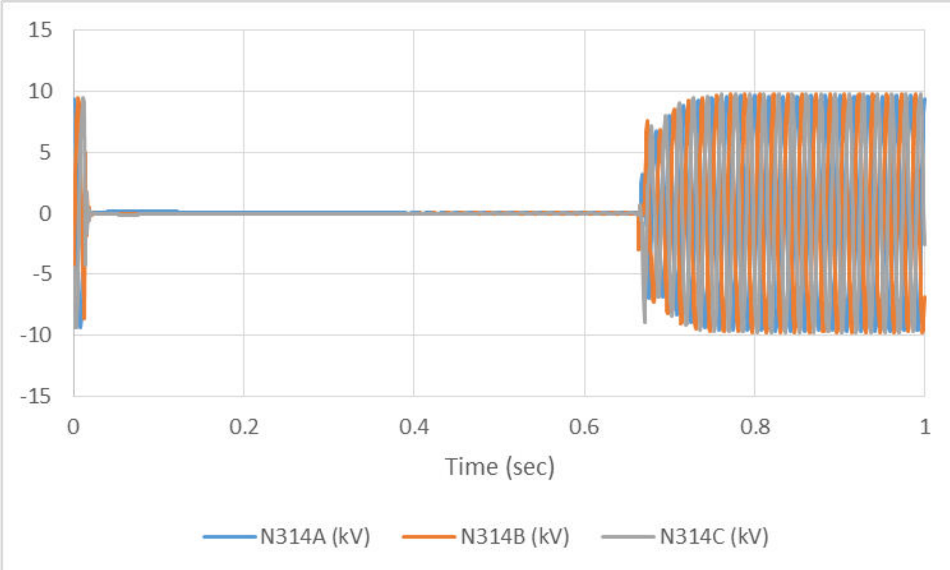


Figure D-61. Battery instantaneous voltage (kV) - High voltage side

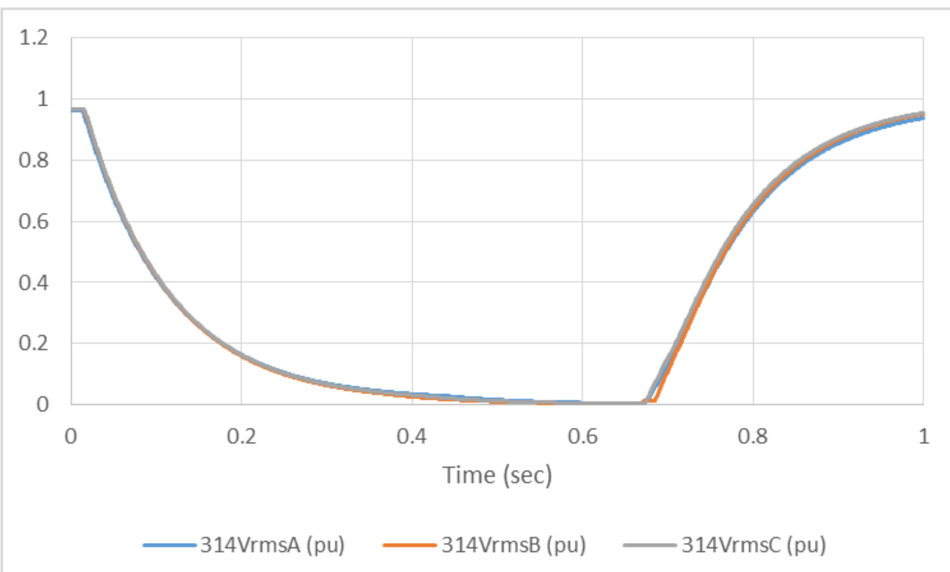


Figure D-62 Battery rms voltage (pu) - High voltage side

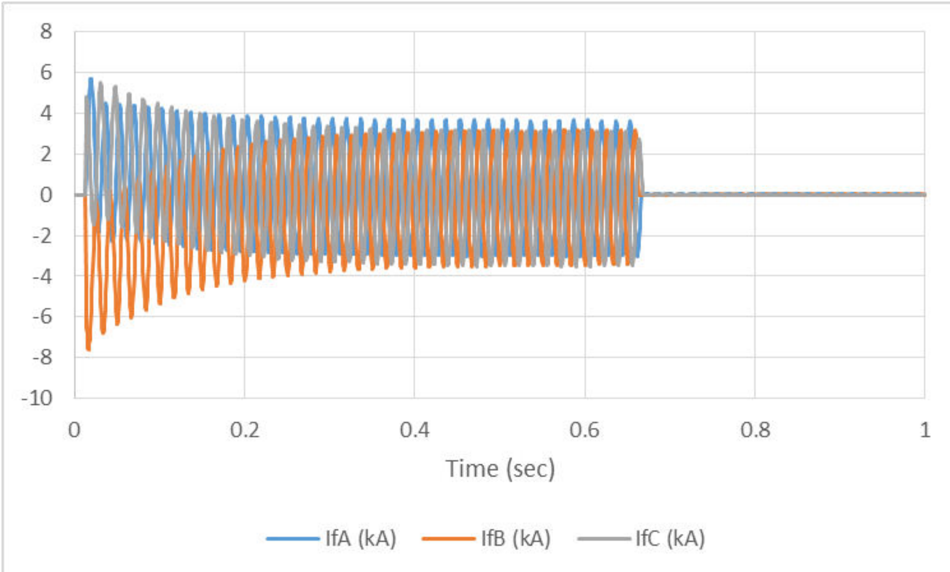


Figure D-63. Fault current at Bus #305 (kA)

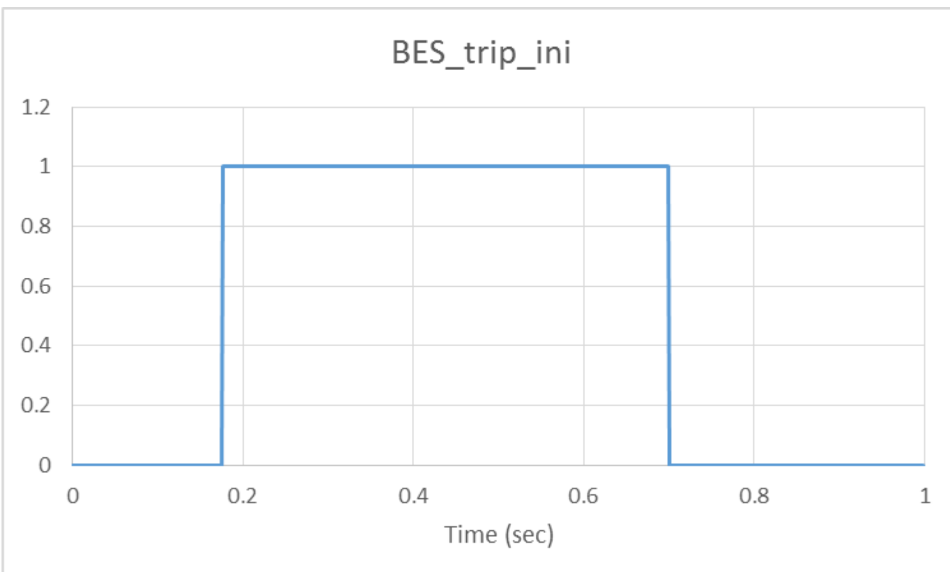


Figure D-64. Battery initial trip signal

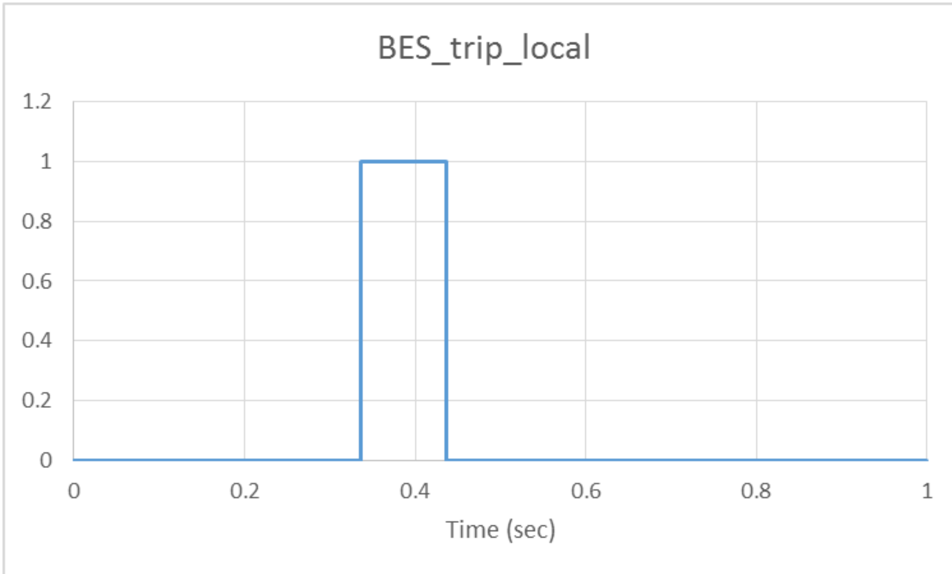


Figure D-65. Battery local trip signal

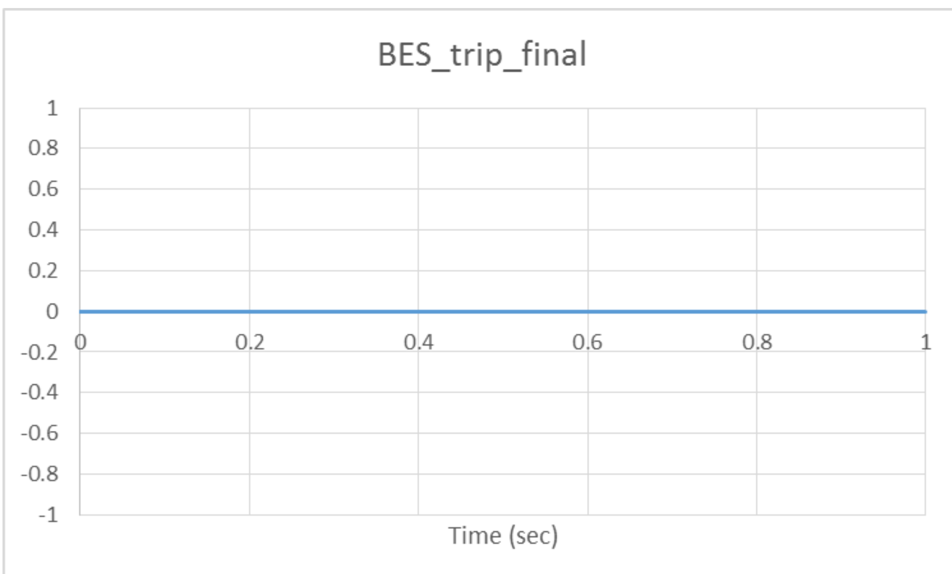


Figure D-66. Battery final trip signal

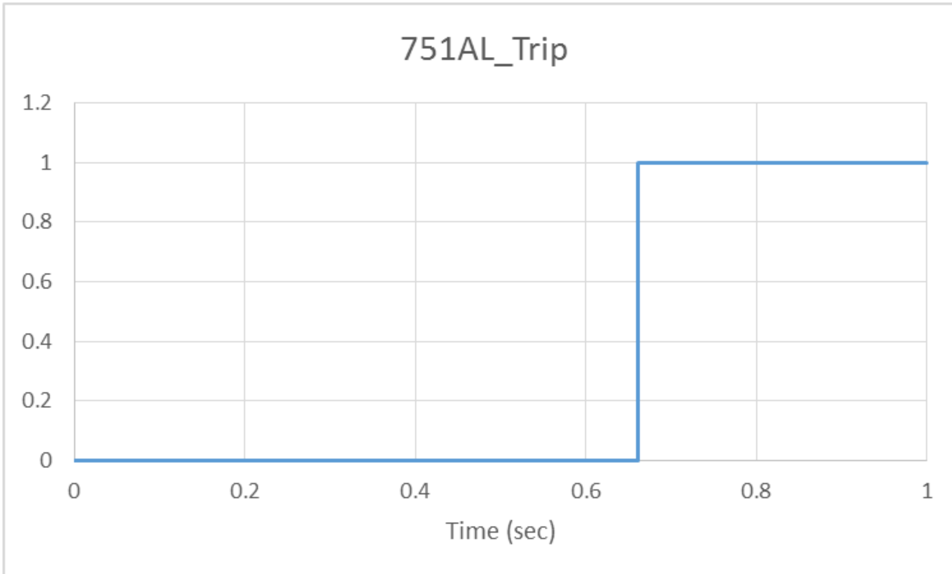


Figure D-67. 751 relay trip signal

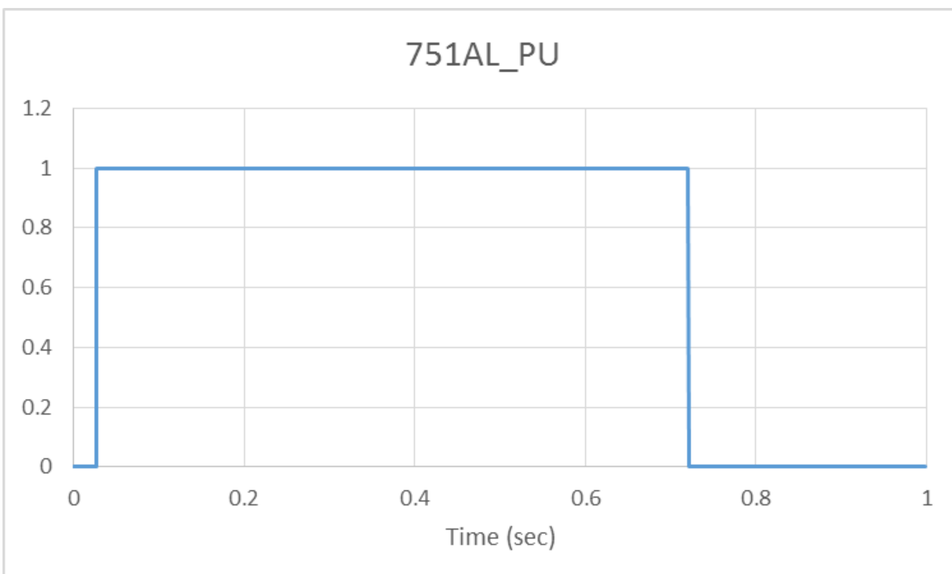


Figure D-68. 751 relay pickup signal

D.6.7 Test Case 7.7 Results

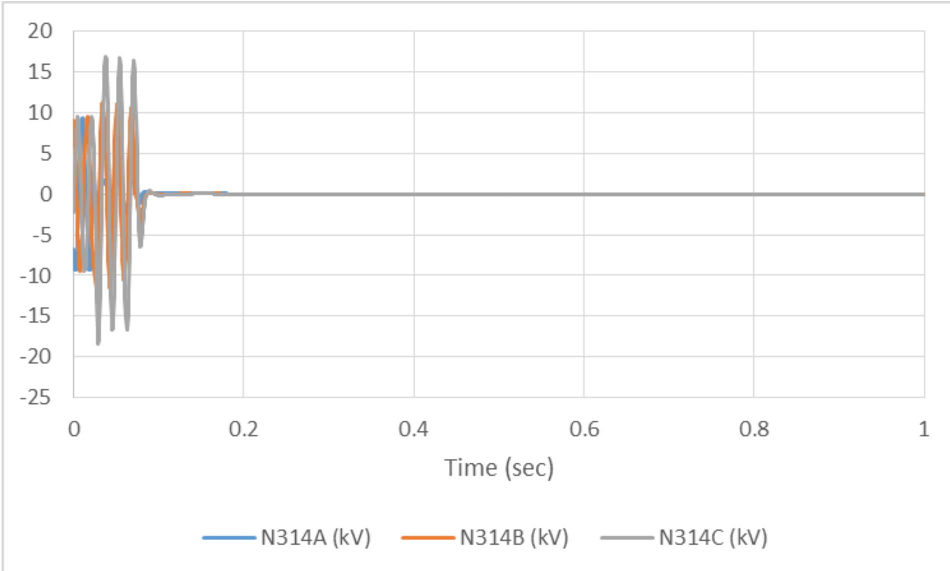


Figure D-69. Battery instantaneous voltage (kV) - High voltage side

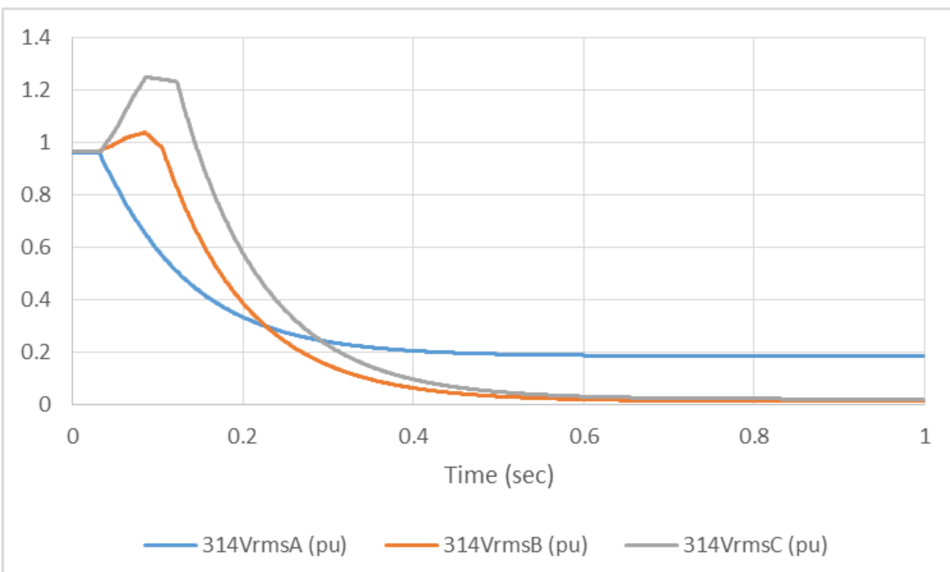


Figure D-70. Battery rms voltage (pu) - High voltage side

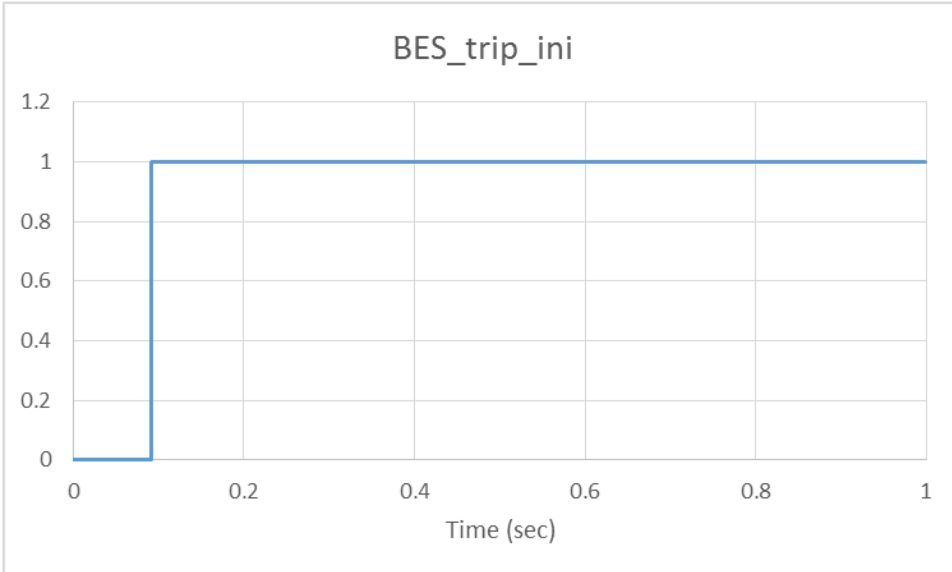


Figure D-71. Battery initial trip signal

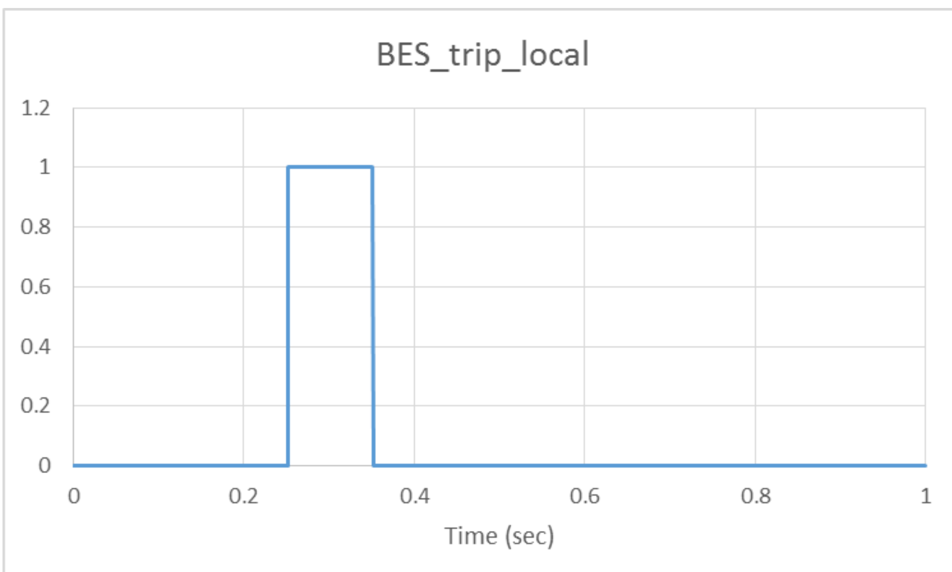


Figure D-72. Battery local trip signal

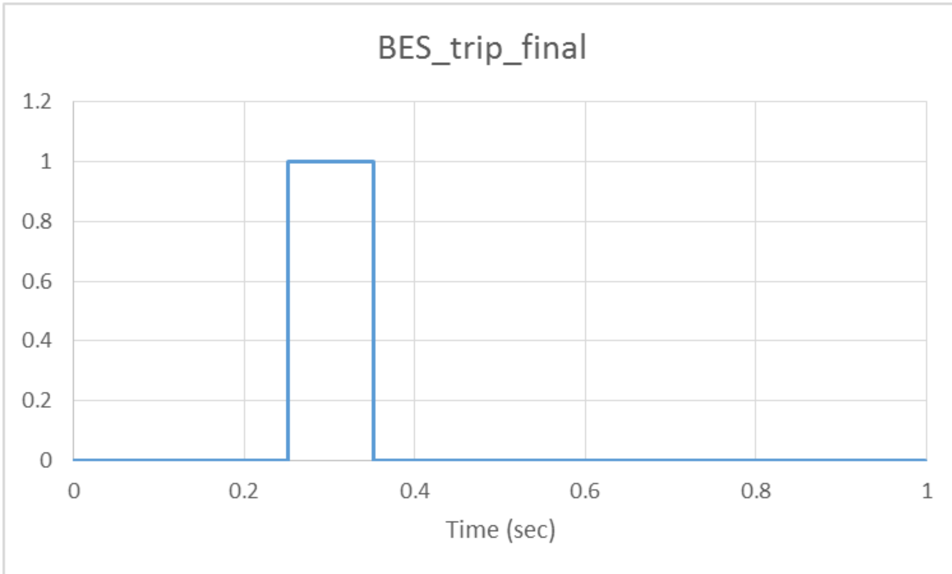


Figure D-73. Battery final trip signal

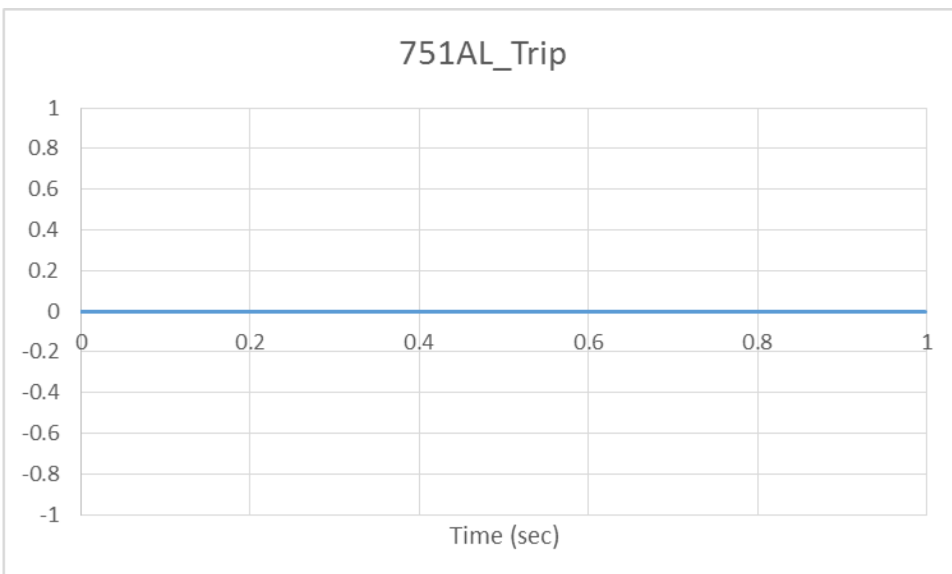


Figure D-74. 751 relay trip signal

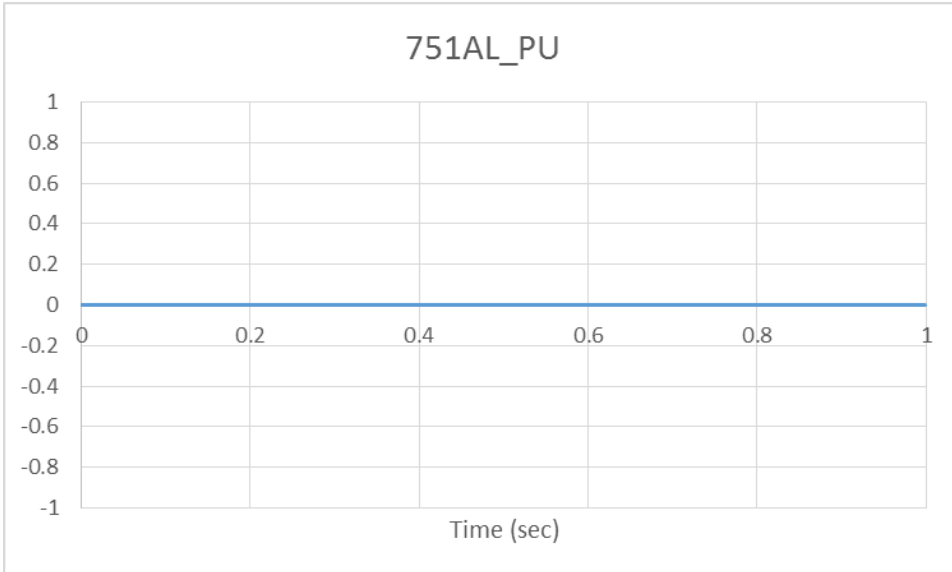


Figure D-75. 751 relay pickup signal

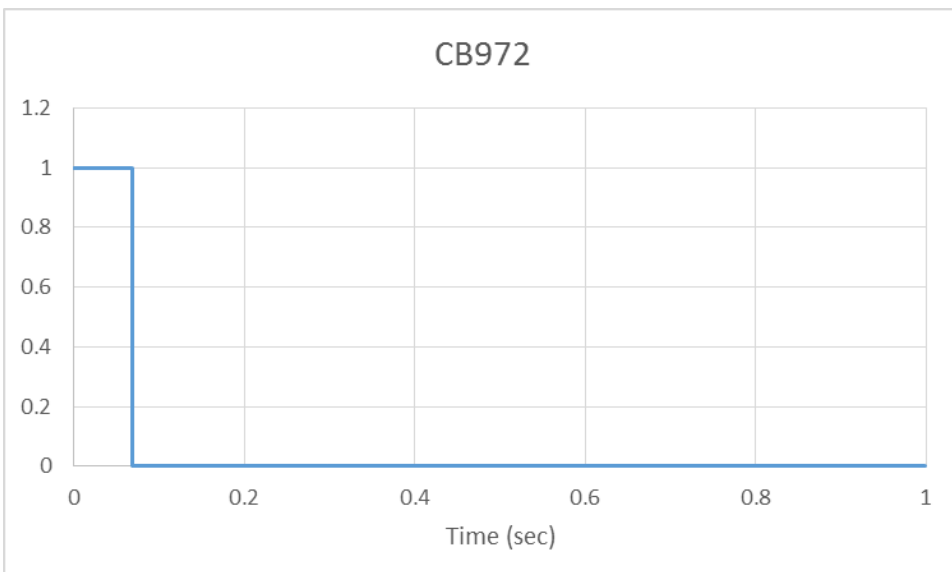


Figure D-76. CBCCR2 status signal

D.6.8 Test Case 7.8 Results

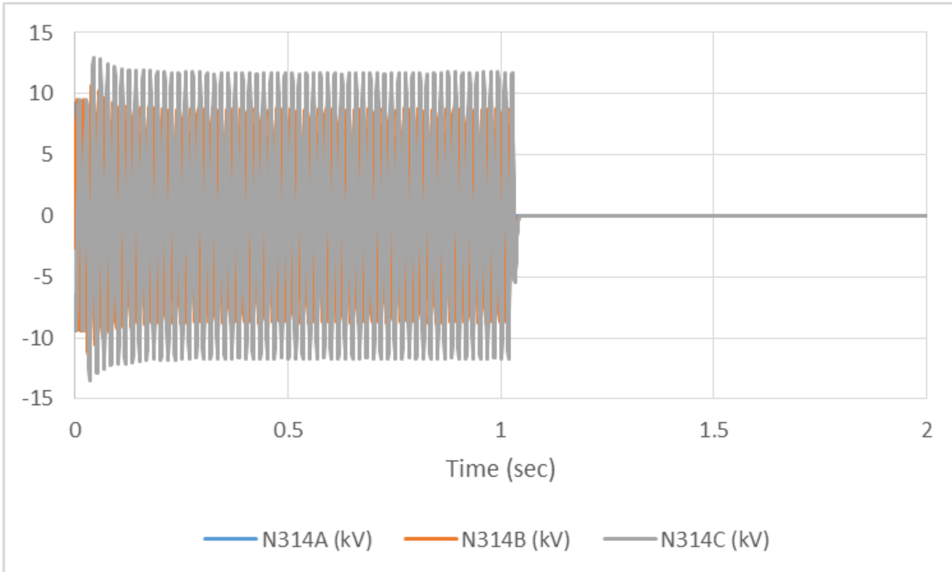


Figure D-77. Battery instantaneous voltage (kV) - High voltage side

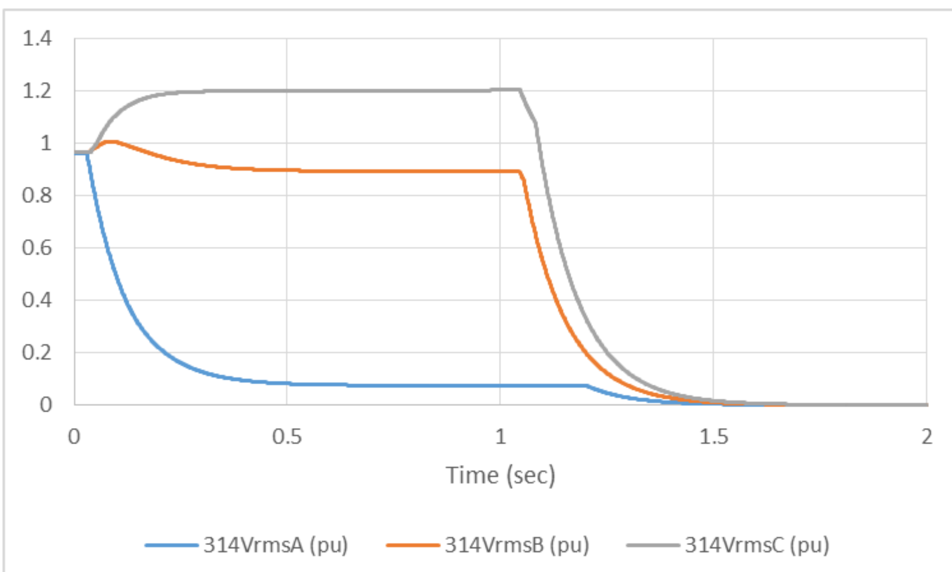


Figure D-78. Battery rms voltage (pu) - High voltage side

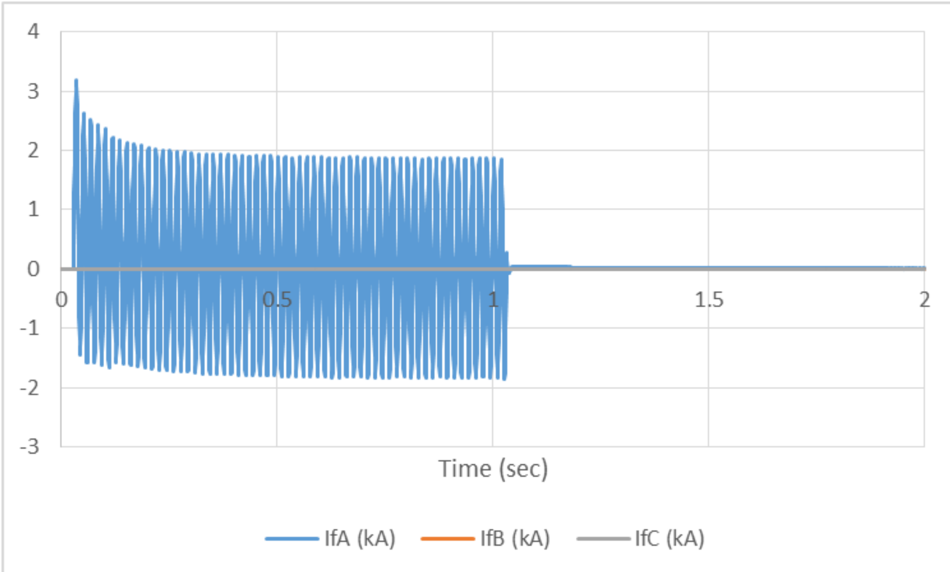


Figure D-79. Fault current at Bus #305 (kA)

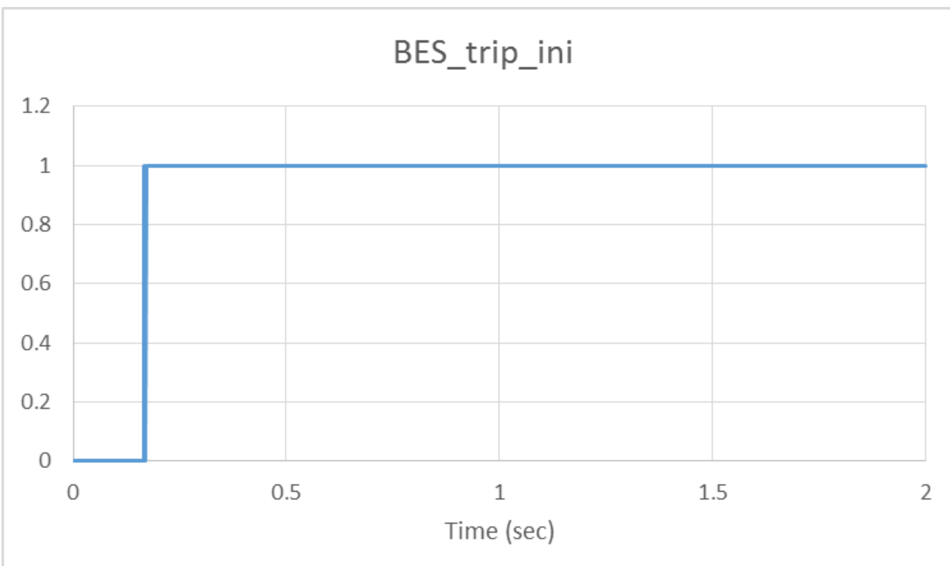


Figure D-80. Battery initial trip signal

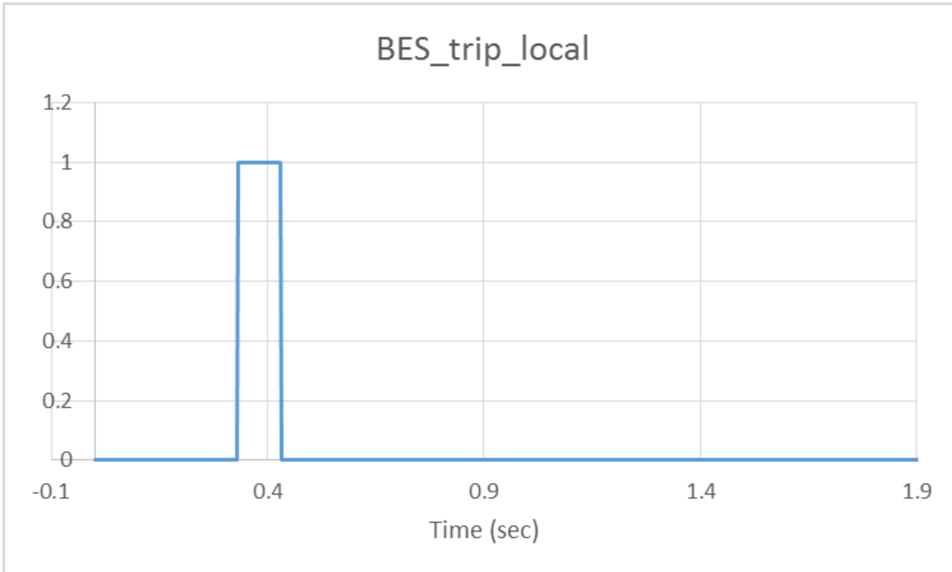


Figure D-81. Battery local trip signal

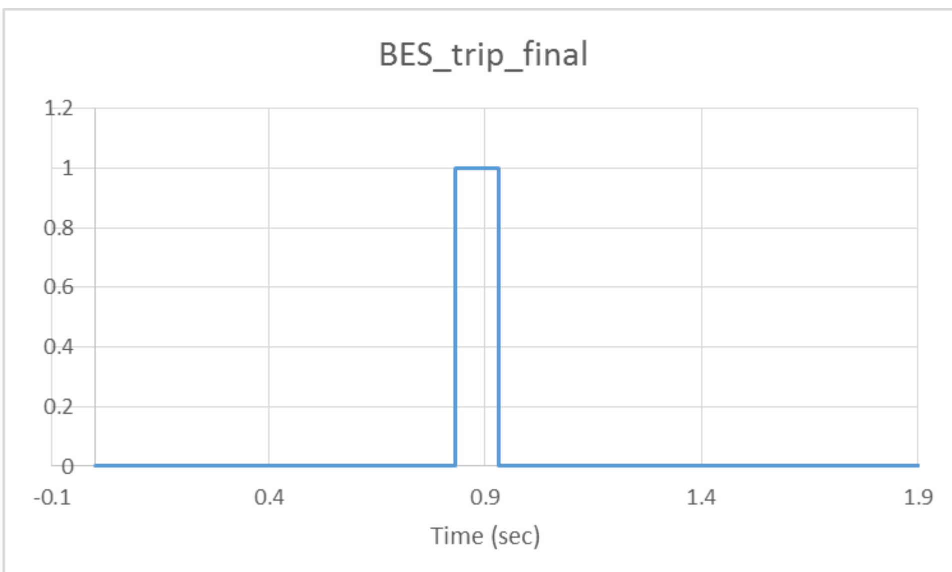


Figure D-82. Battery final trip signal

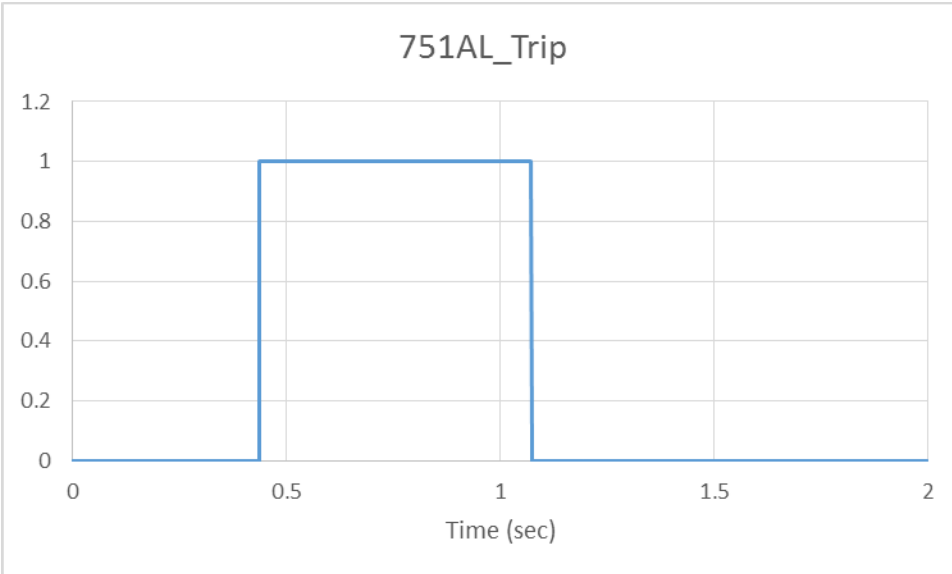


Figure D-83. 751 relay trip signal

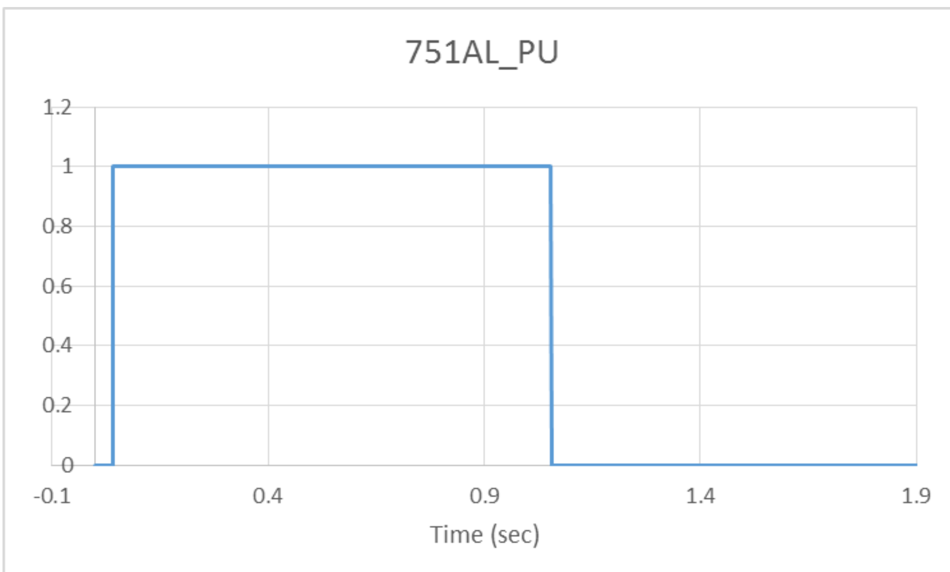


Figure D-84. 751 relay pickup signal

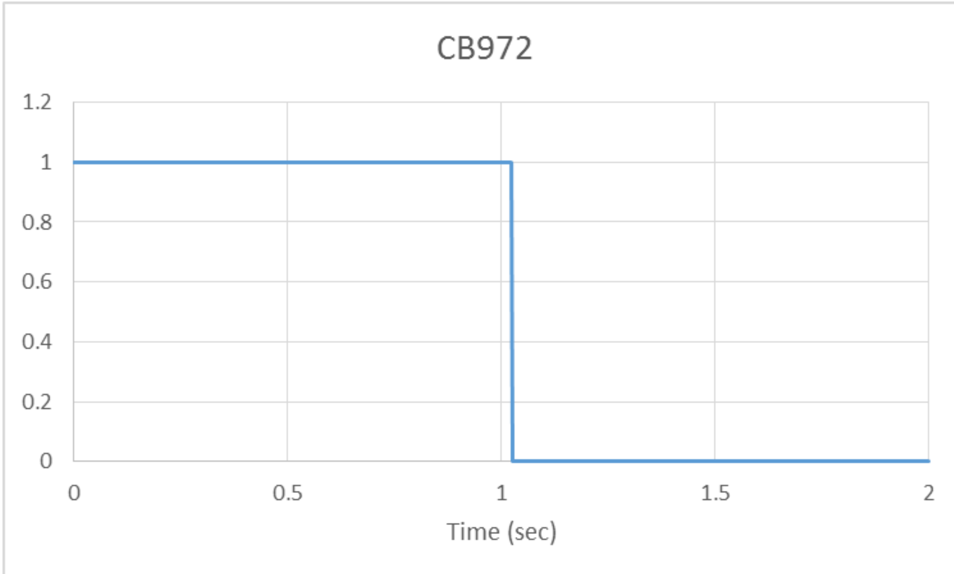


Figure D-85. CBCCR2 status signal

D.6.9 Test Case 7.9 Results

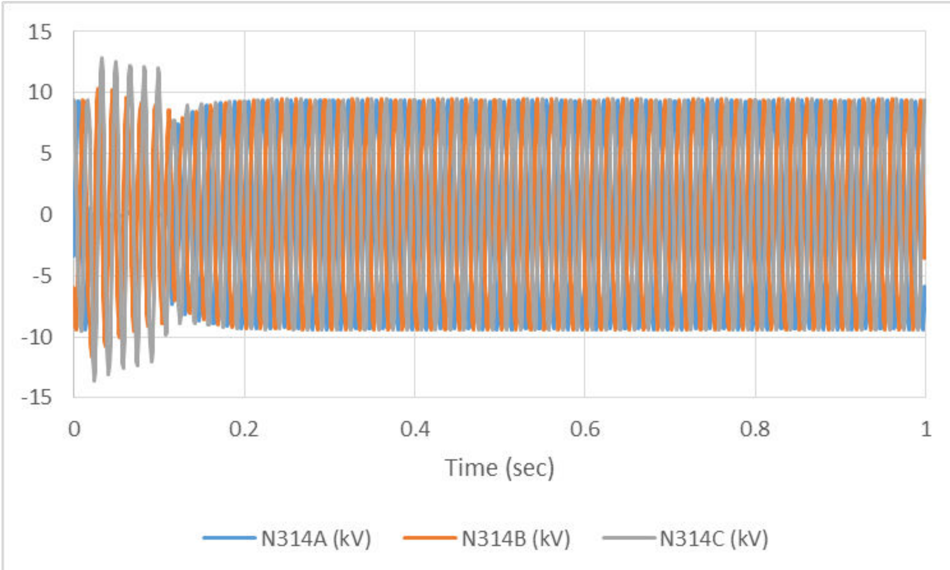


Figure D-86. Battery instantaneous voltage (kV) - High voltage side

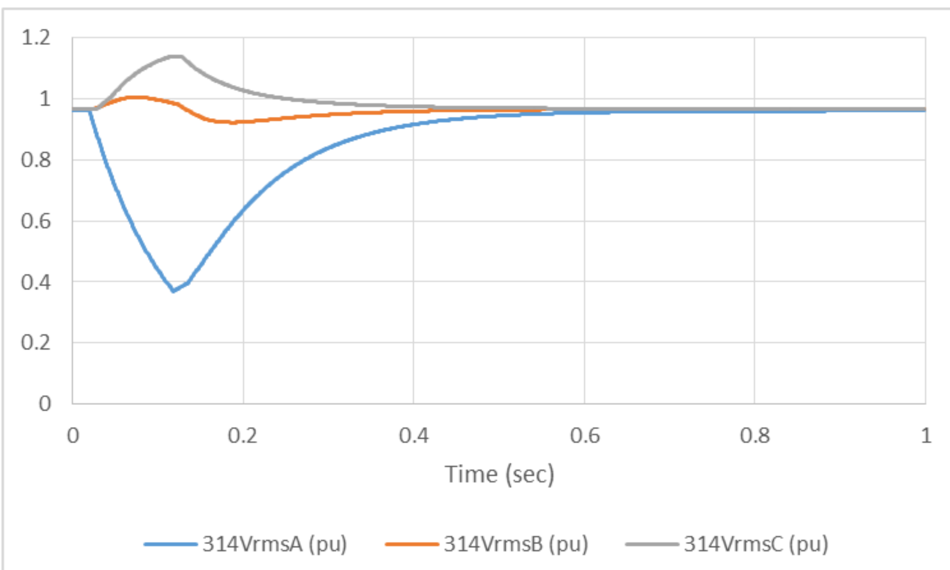


Figure D-87. Battery rms voltage (pu) - High voltage side

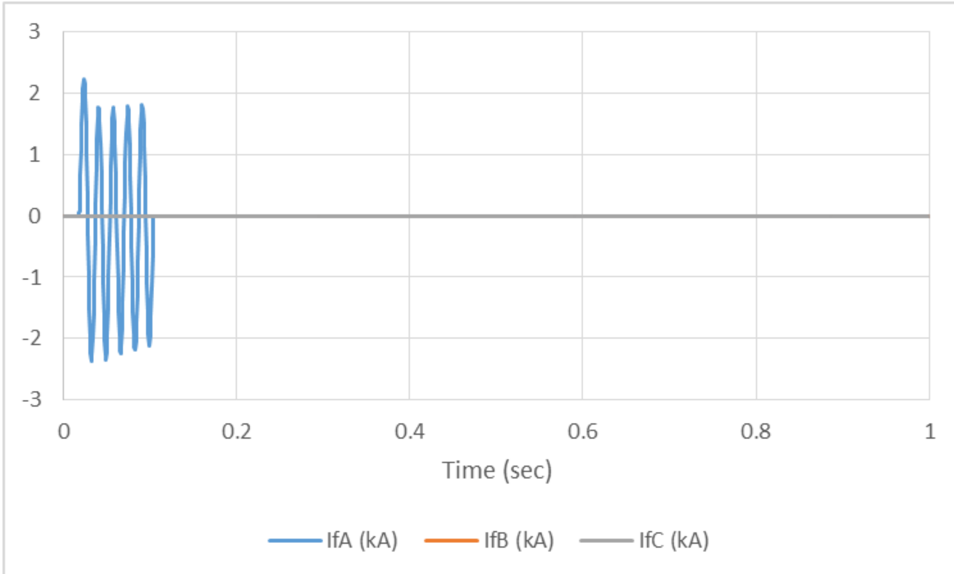


Figure D-88. Fault current at Bus #305 (kA)

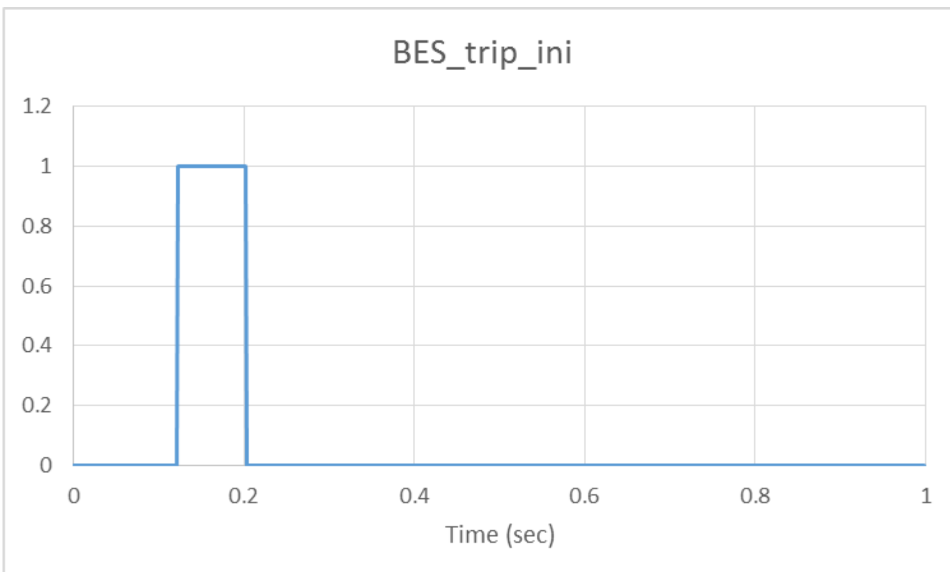


Figure D-89. Battery initial trip signal

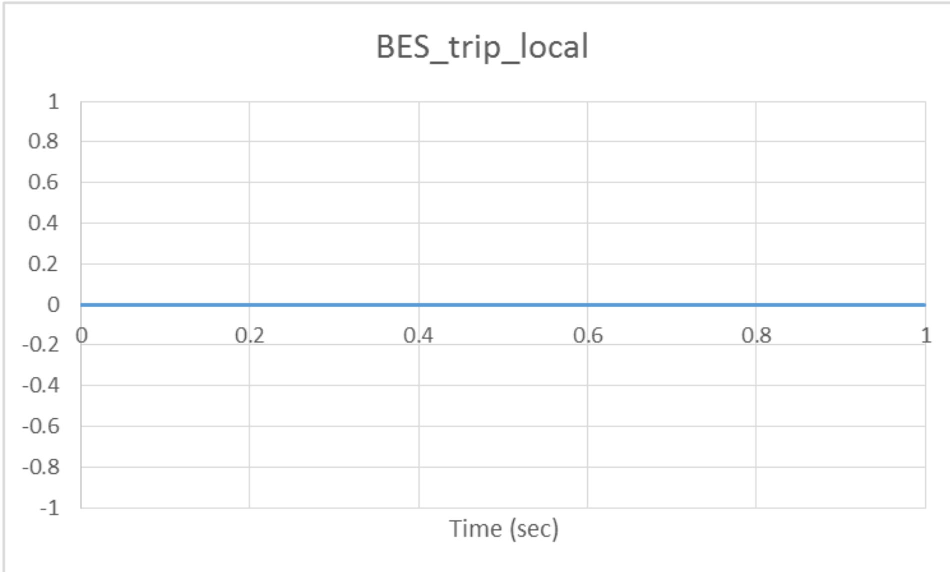


Figure D-90. Battery local trip signal

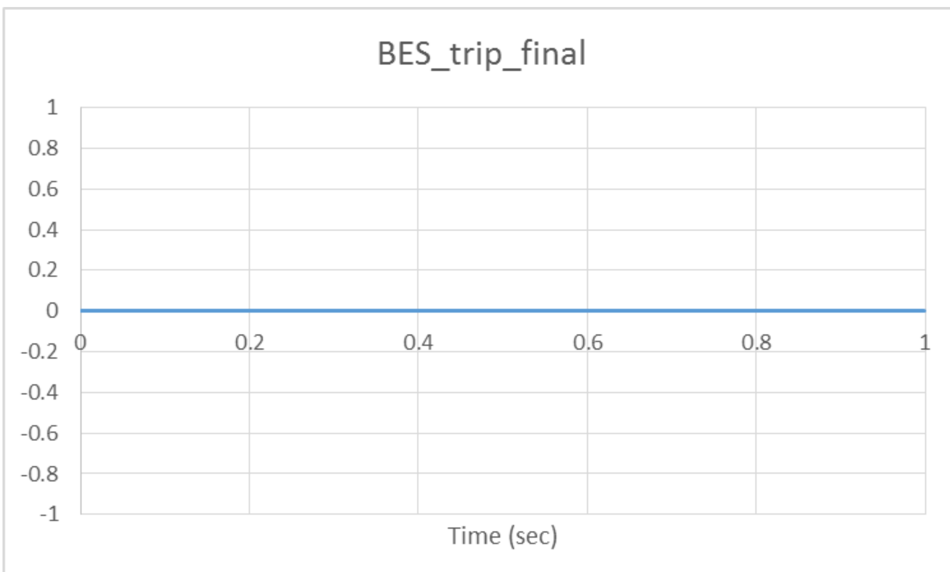


Figure D-91. Battery final trip signal

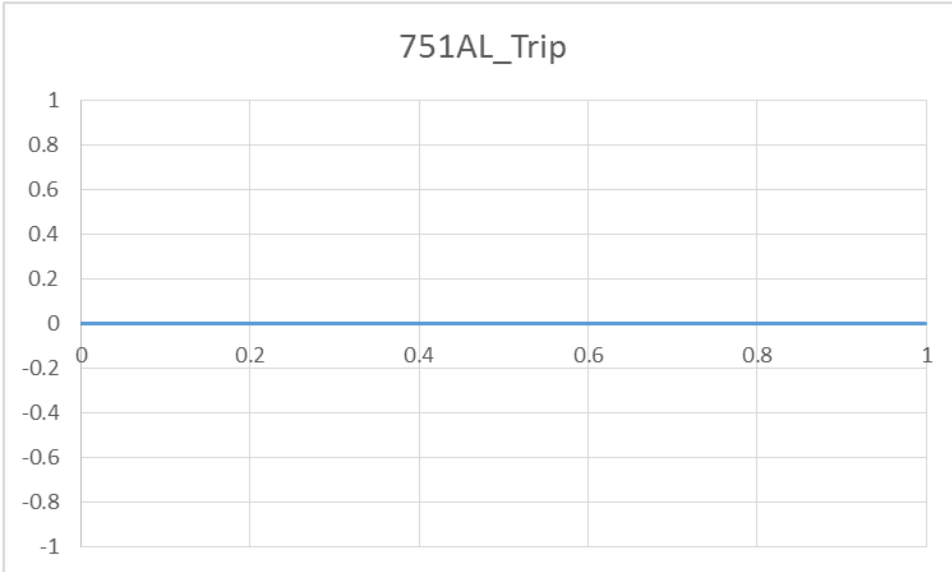


Figure D-92. 751 relay trip signal

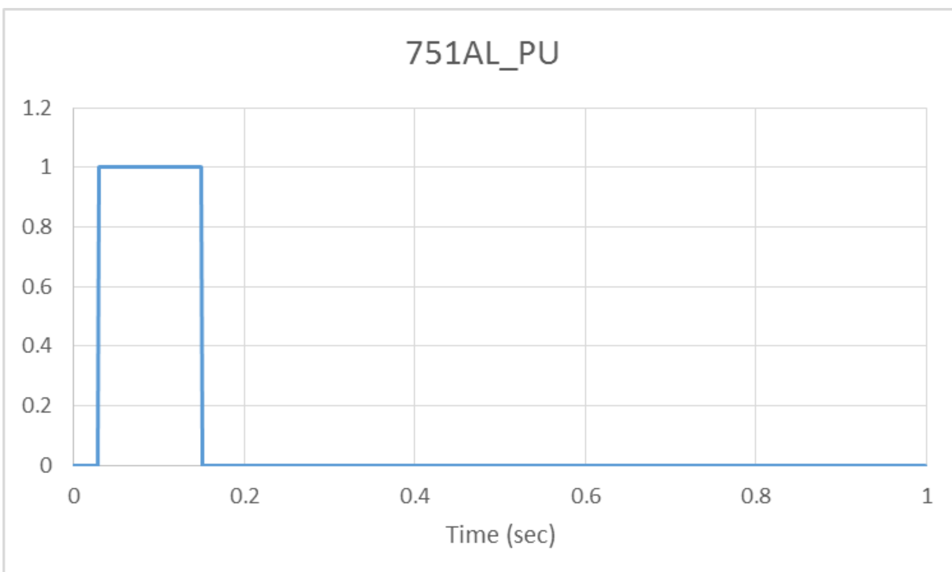


Figure D-93. 751 relay pickup signal

D.6.10 Test Case 7.10 Results

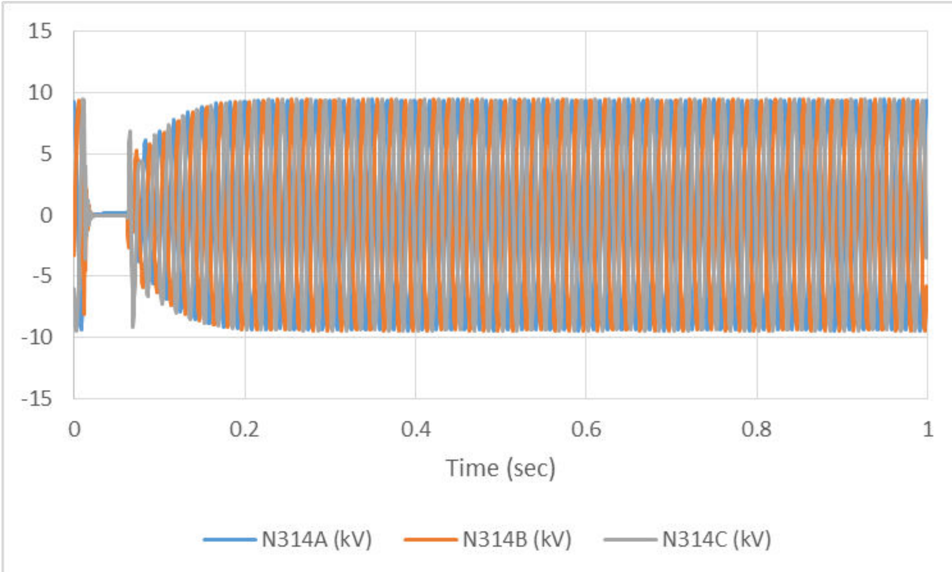


Figure D-94. Battery instantaneous voltage (kV) - High voltage side

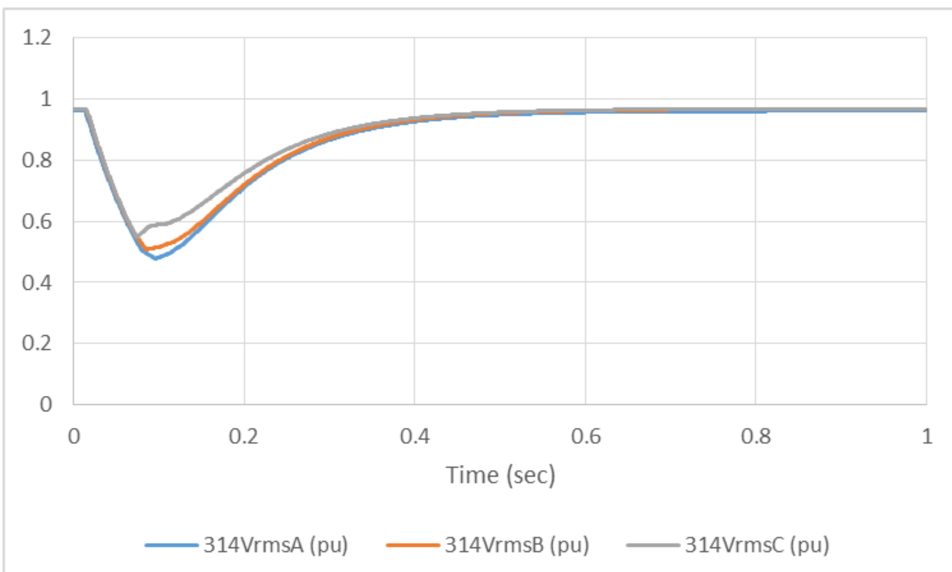


Figure D-95. Battery rms voltage (pu) - High voltage side

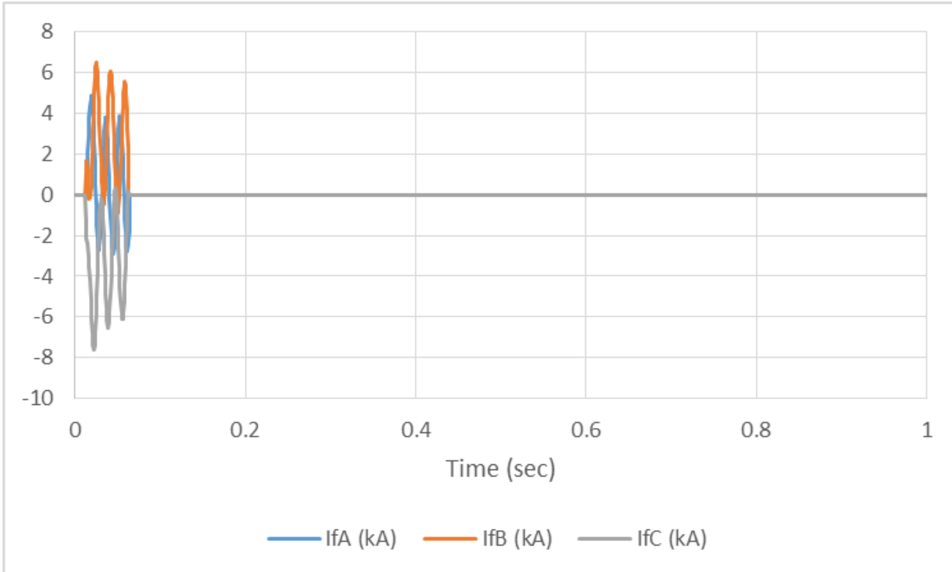


Figure D-96. Fault current at Bus #305 (kA)

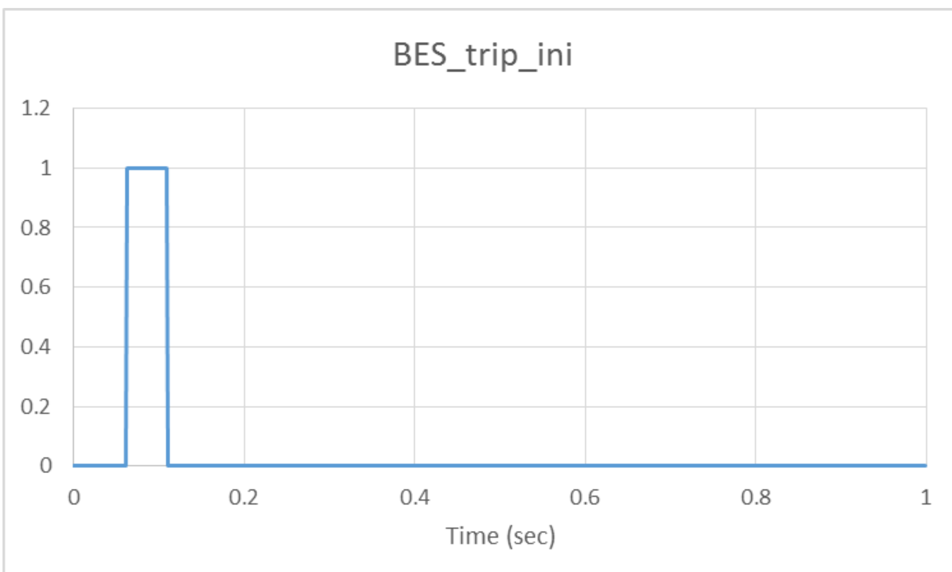


Figure D-97. Battery initial trip signal

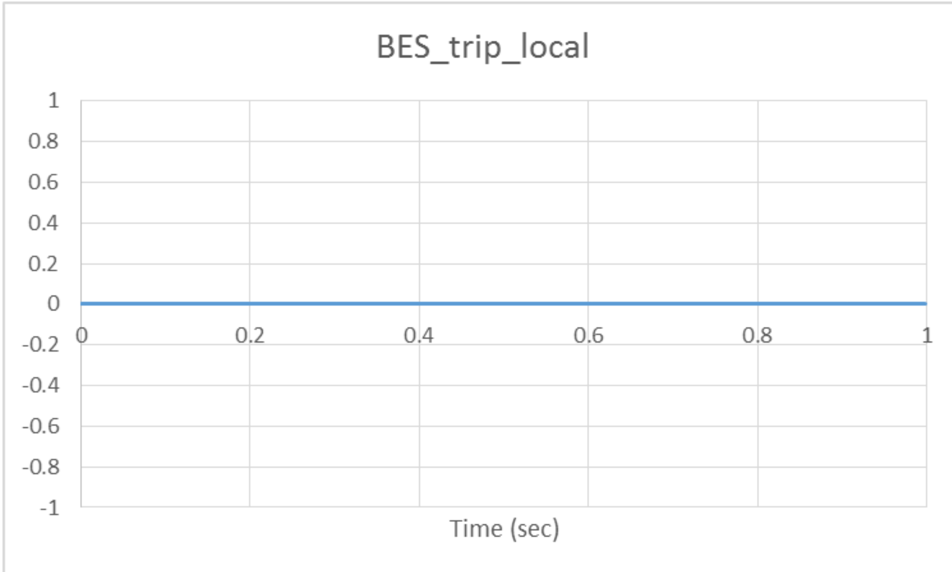


Figure D-98. Battery local trip signal

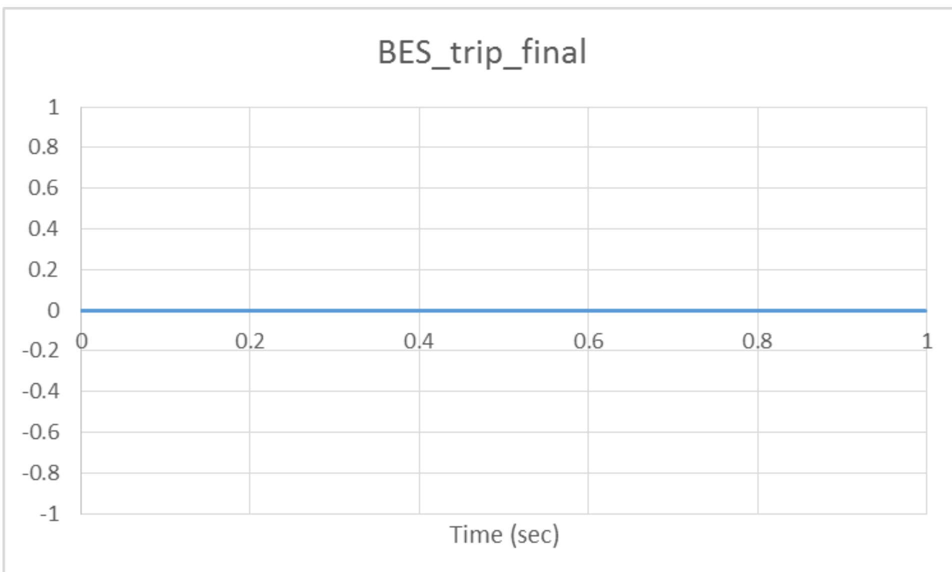


Figure D-99. Battery final trip signal

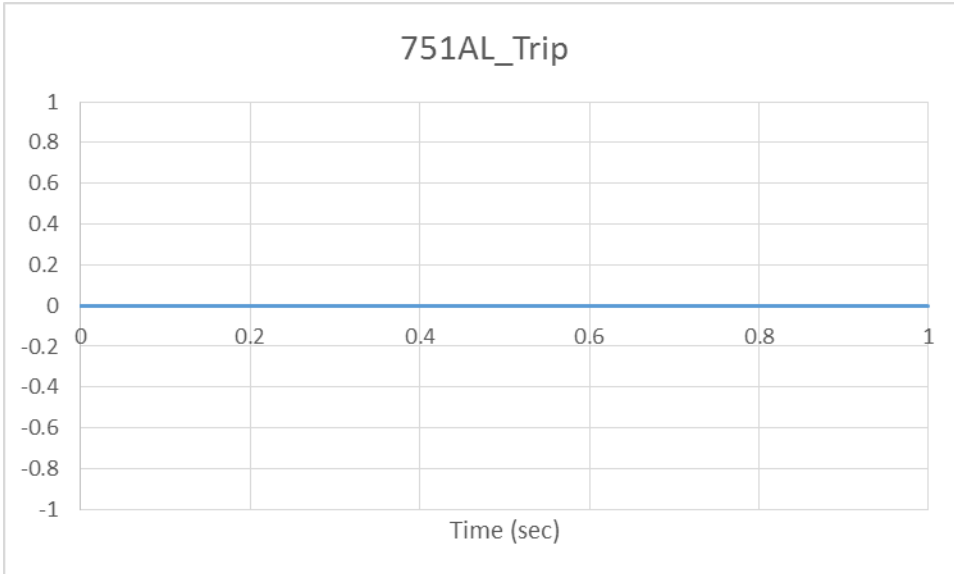


Figure D-100. 751 relay trip signal

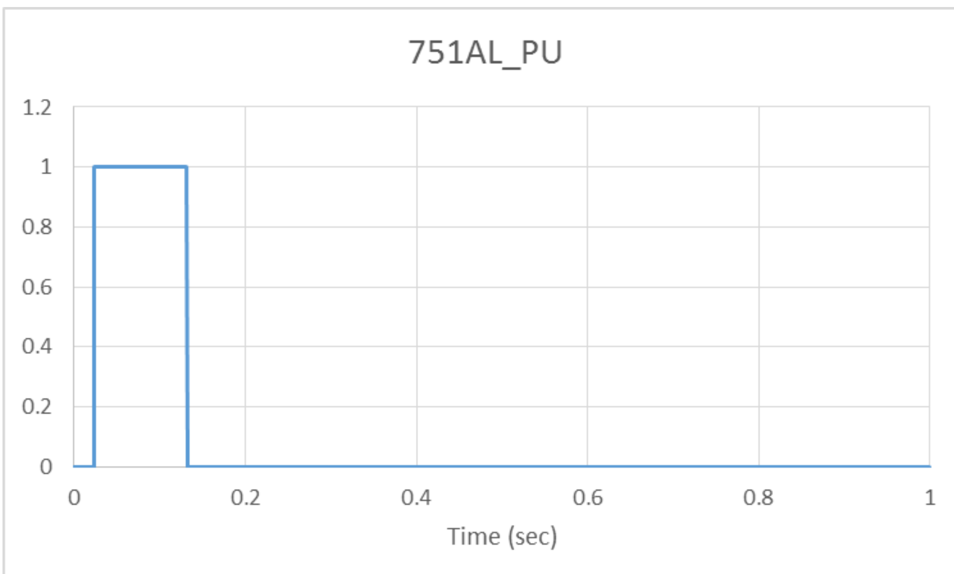


Figure D-101. 751 relay pickup signal

D.6.11 Test Case 7.11 Results

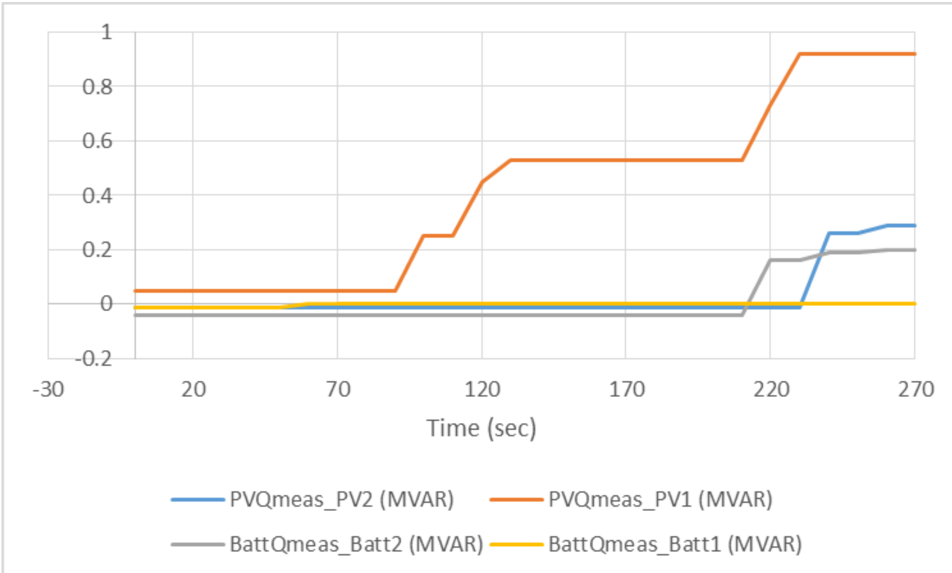


Figure D-102. DER reactive power measurements (Mvar)

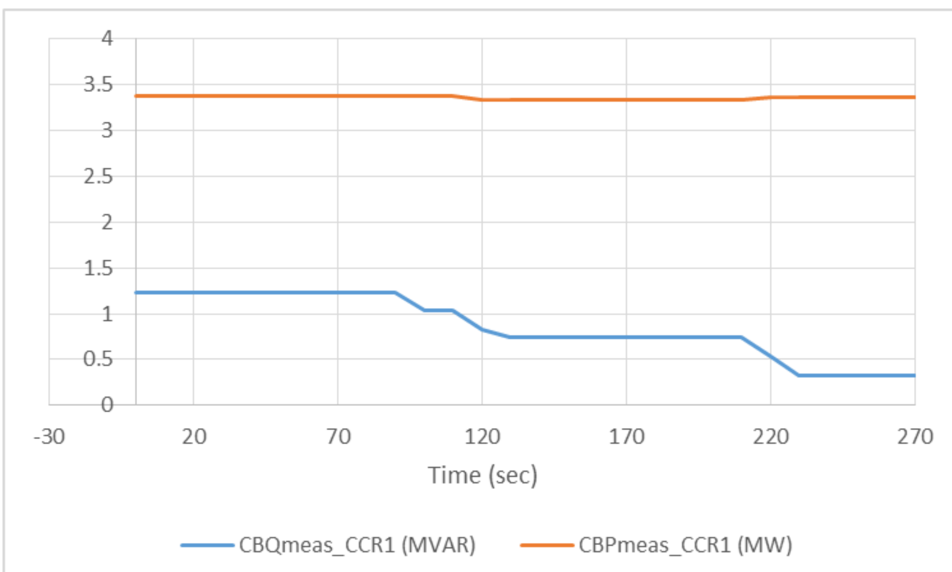


Figure D-103. CCR1 power flow measurement (MW & Mvar)

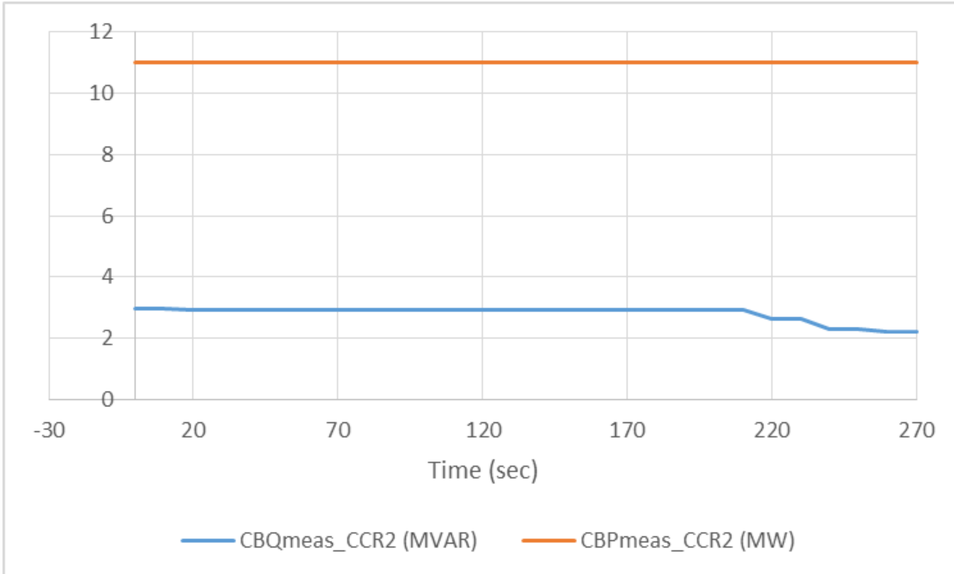


Figure D-104. CCR2 power flow measurement (MW & Mvar)

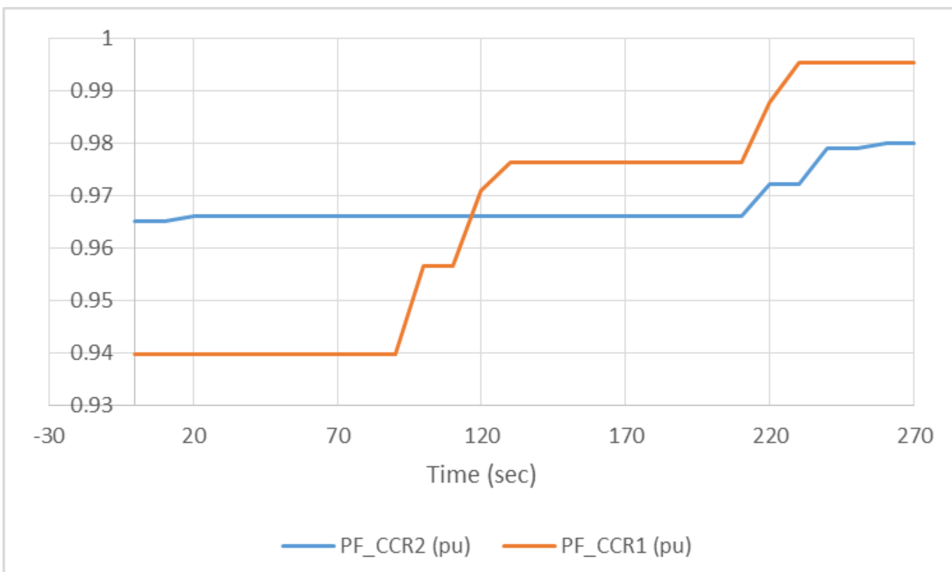


Figure D-105. CCR1 & CCR2 power factor measurement (pu)

D.6.12 Test Case 7.12 Results

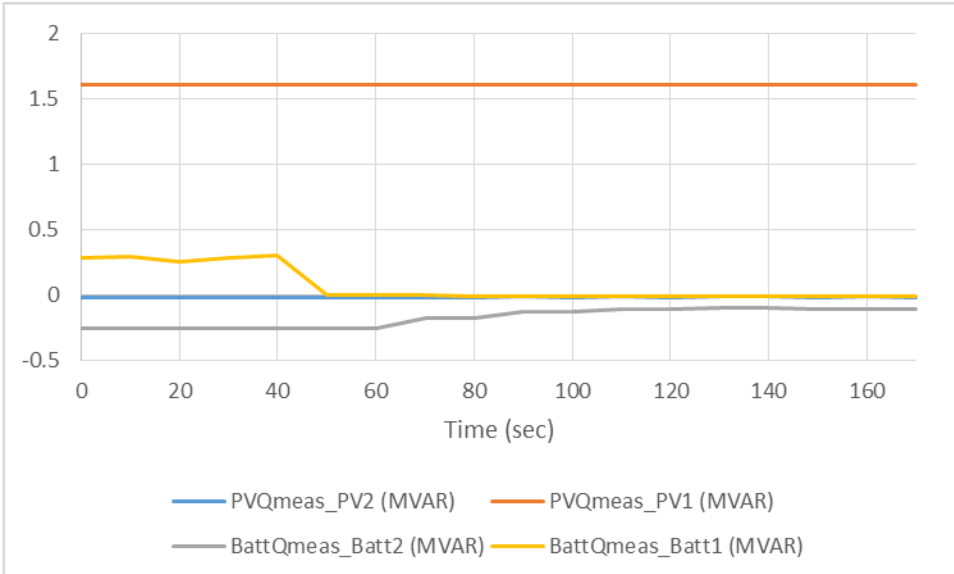


Figure D-106. DER reactive power measurements (Mvar)

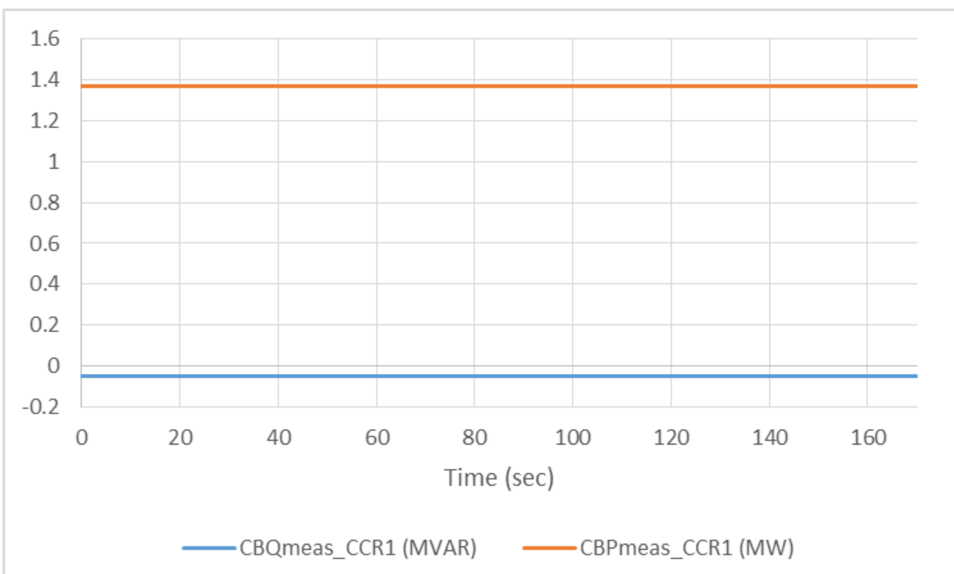


Figure D-107. CCR1 power flow measurement (MW & Mvar)

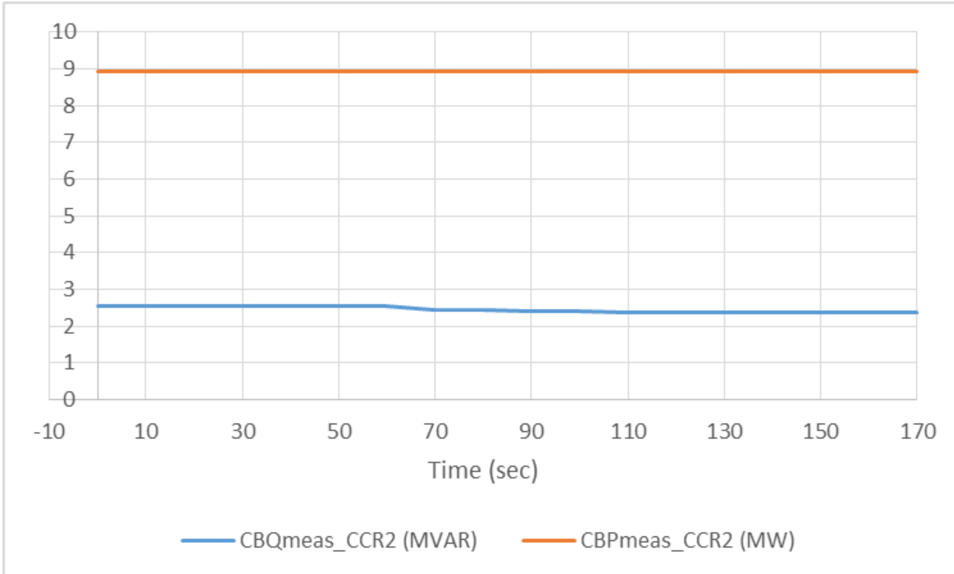


Figure D-108. CCR2 power flow measurement (MW & Mvar)

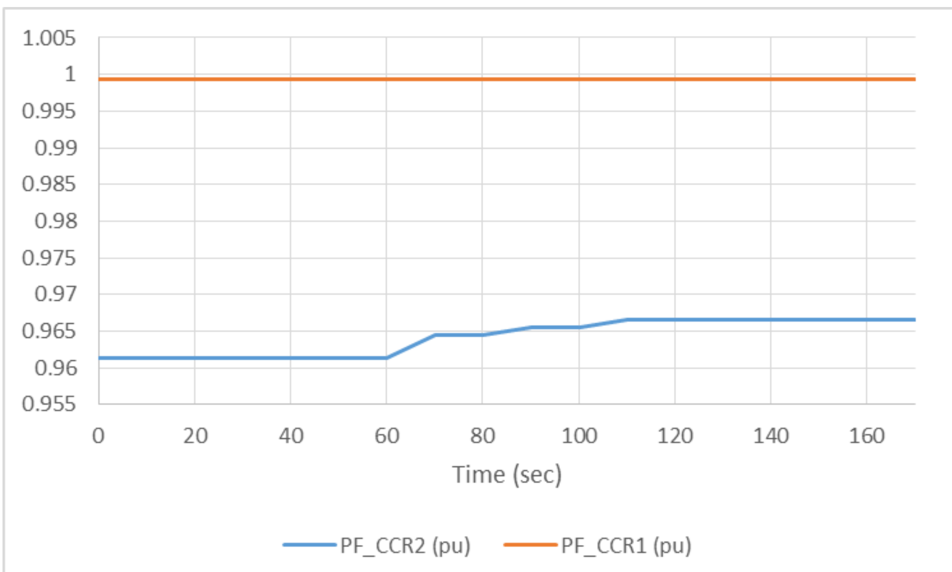


Figure D-109. CCR1 & CCR2 power factor measurement (pu)

D.7 Use Case 8: Test Records for Emergency load management tests

D.7.1 Test Case 8.1 Results

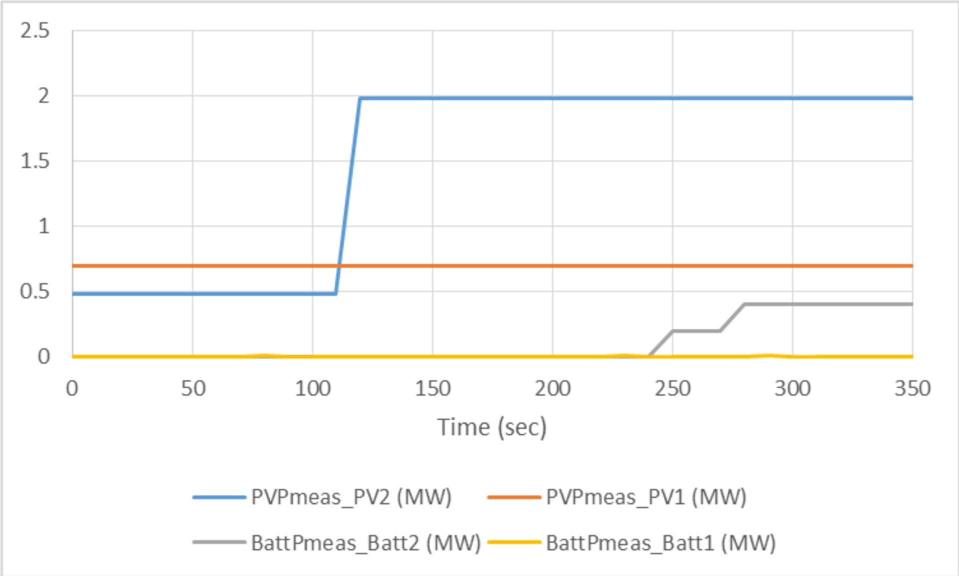


Figure D-110. DER active power flow measurements (MW)

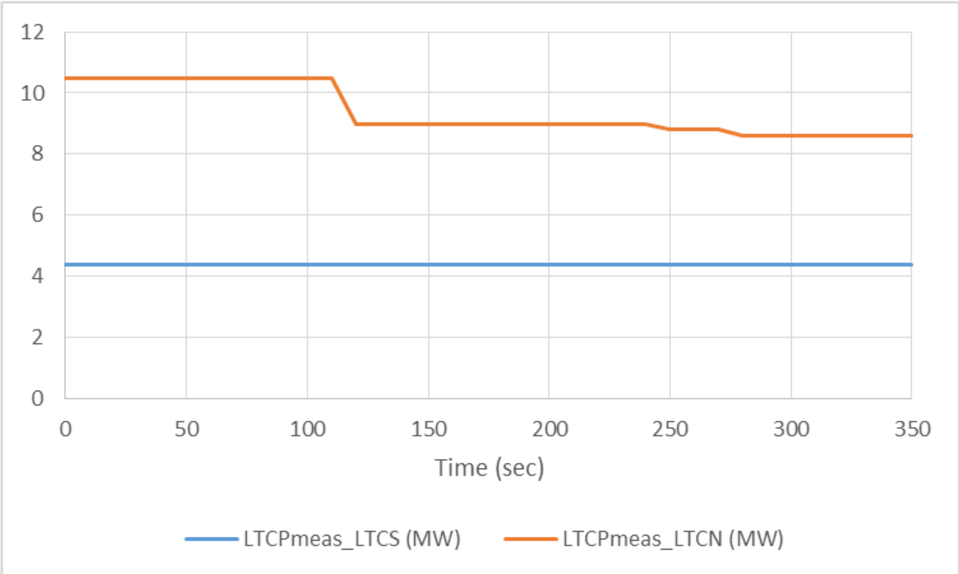


Figure D-111. LTC active power flow measurements (MW)

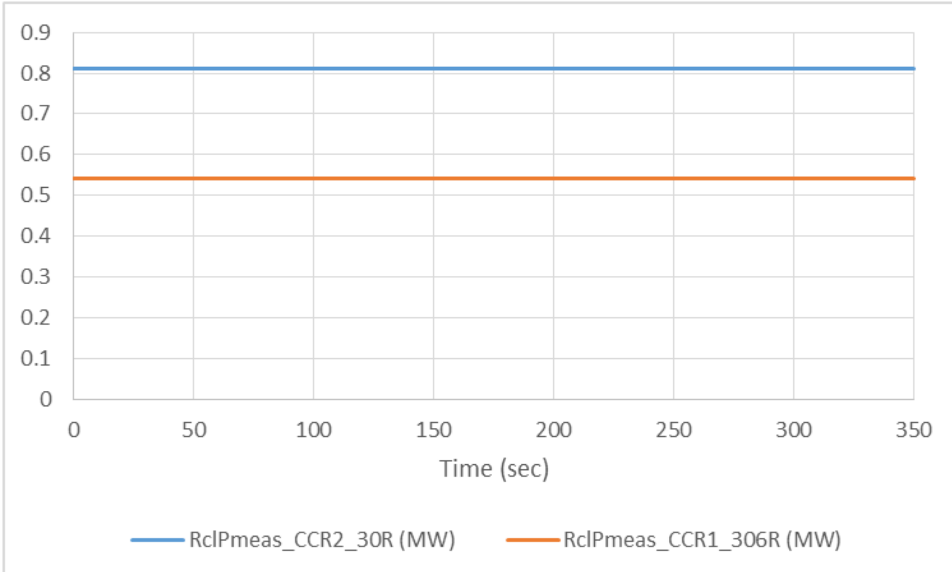


Figure D-112. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.2 Test Case 8.2 Results

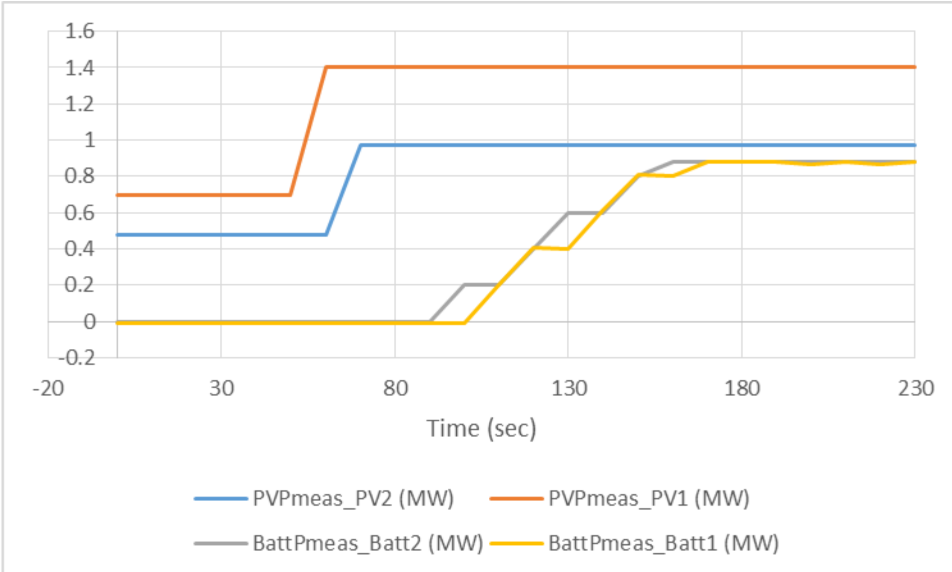


Figure D-113. DER active power flow measurements (MW)

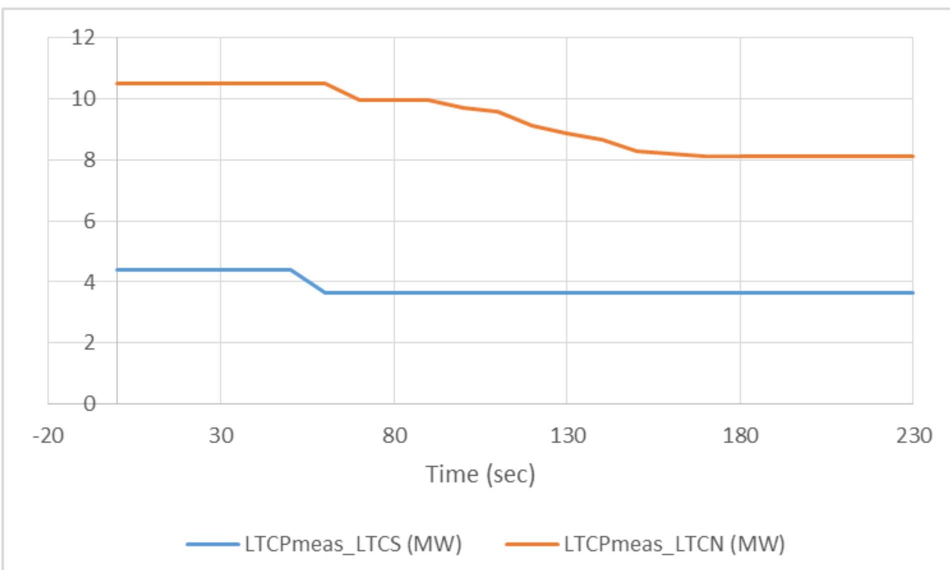


Figure D-114. LTC active power flow measurements (MW)

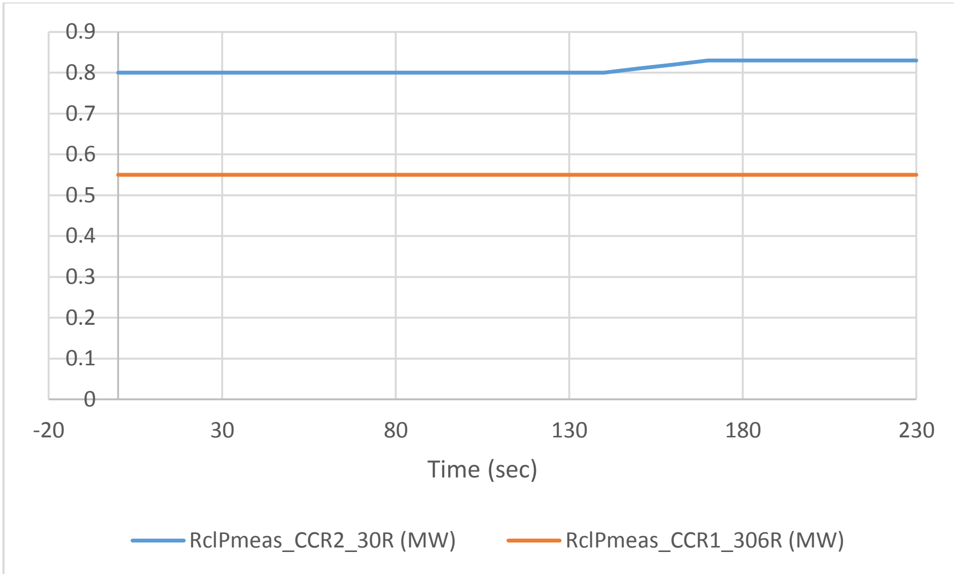


Figure D-115. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.3 Test Case 8.3 Results

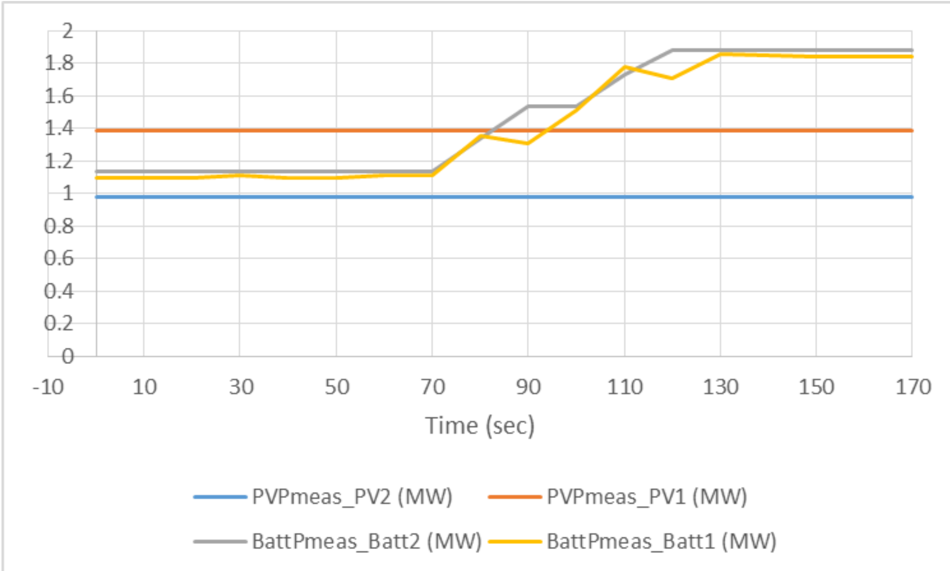


Figure D-116. DER active power flow measurements (MW)

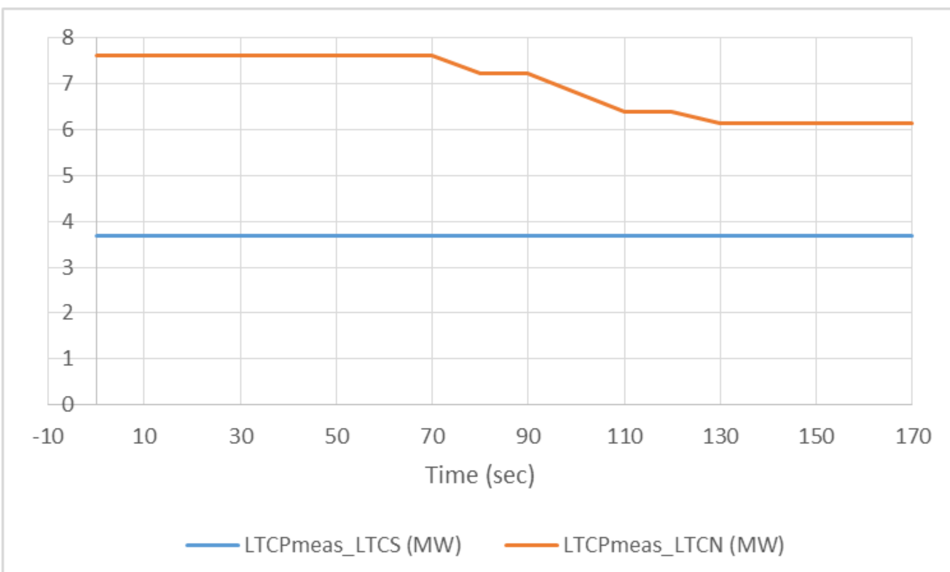


Figure D-117. LTC active power flow measurements (MW)

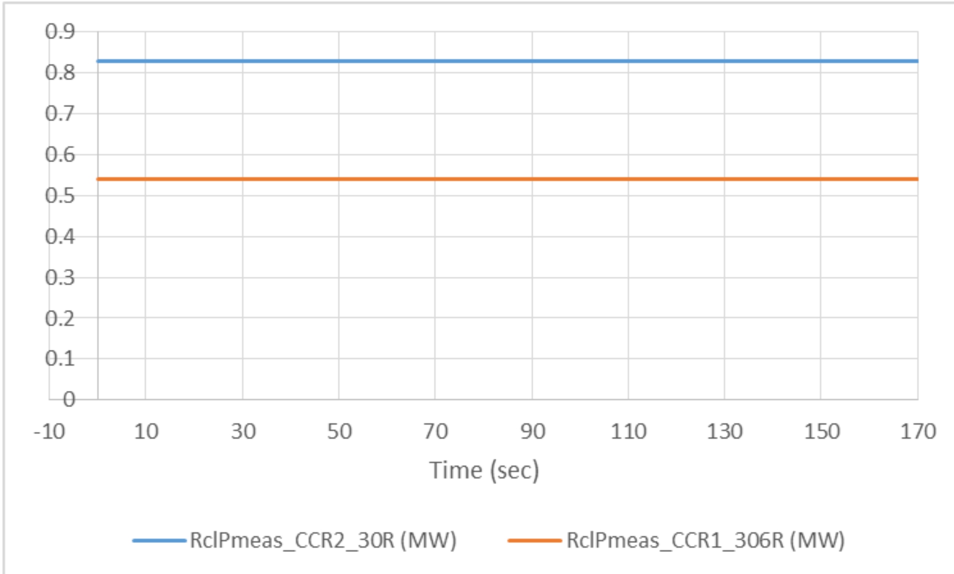


Figure D-118. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.4 Test Case 8.4 Results

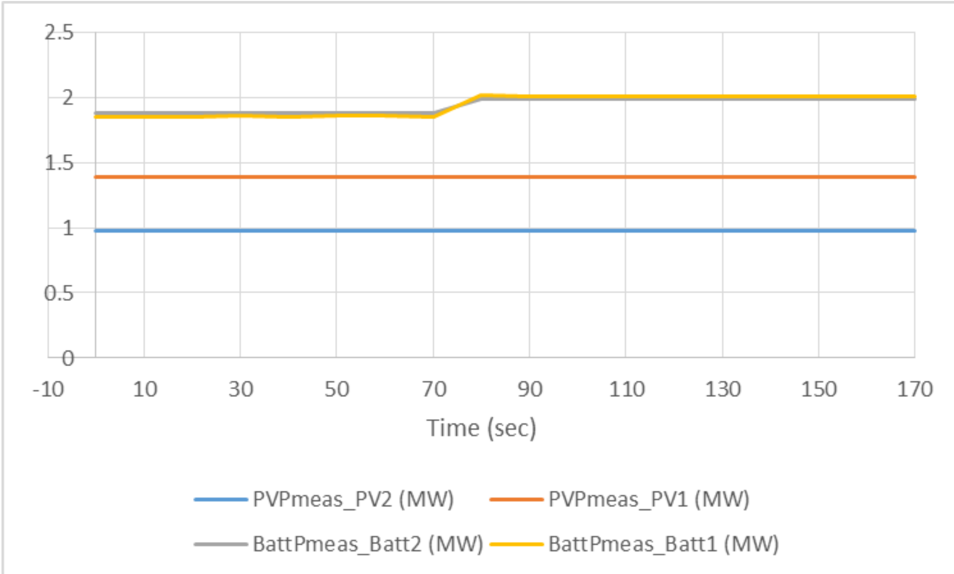


Figure D-119. DER active power flow measurements (MW)

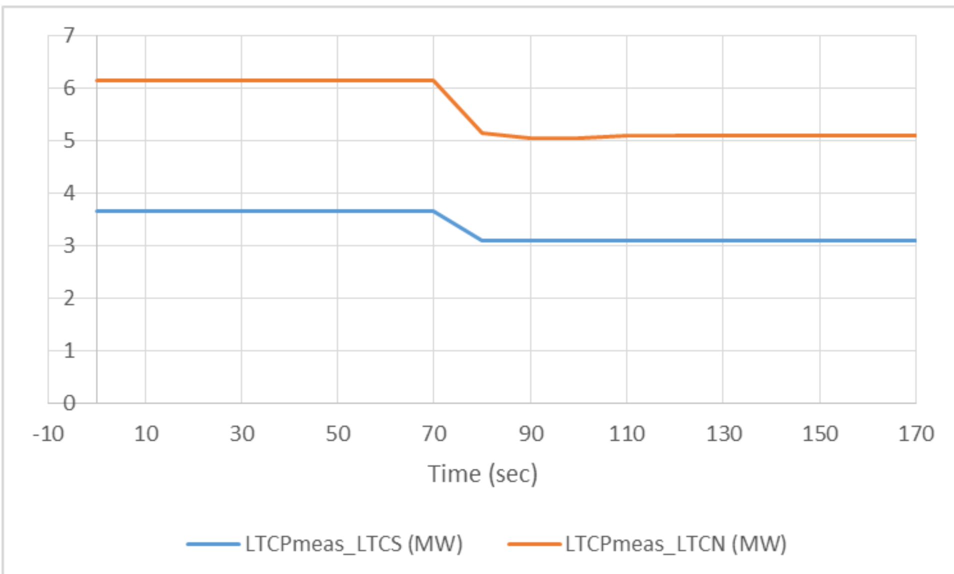


Figure D-120. LTC active power flow measurements (MW)

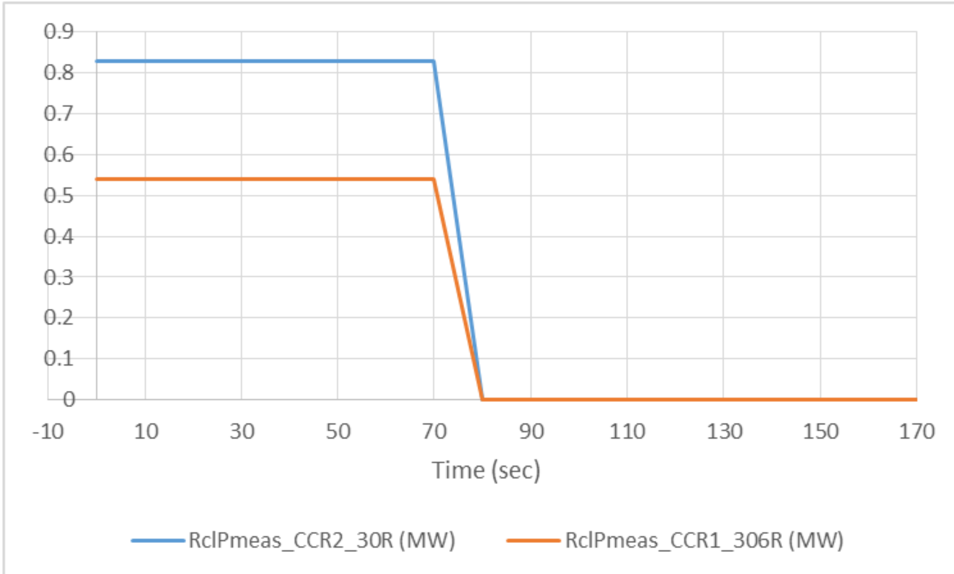


Figure D-121. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.5 Test Case 8.5 Results

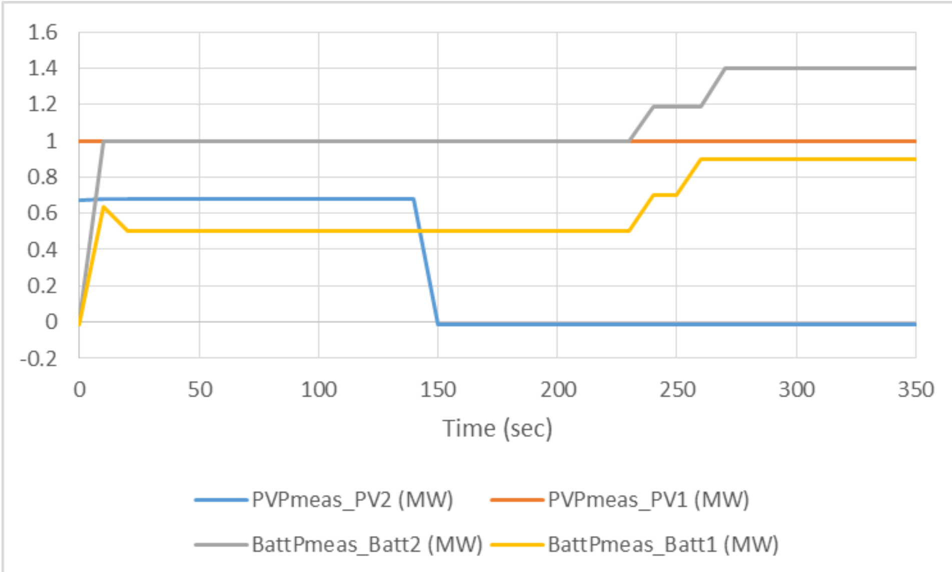


Figure D-122. DER active power flow measurements (MW)

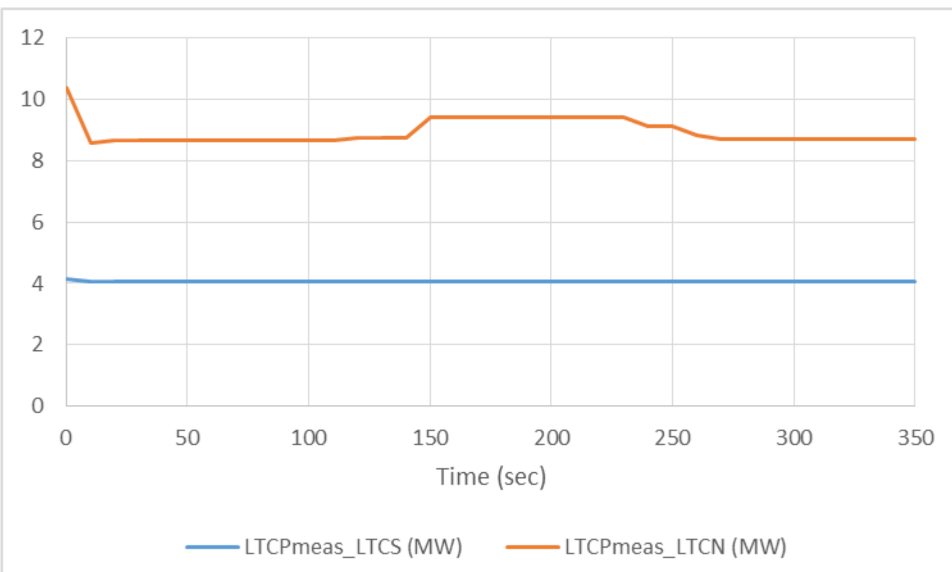


Figure D-123. LTC active power flow measurements (MW)

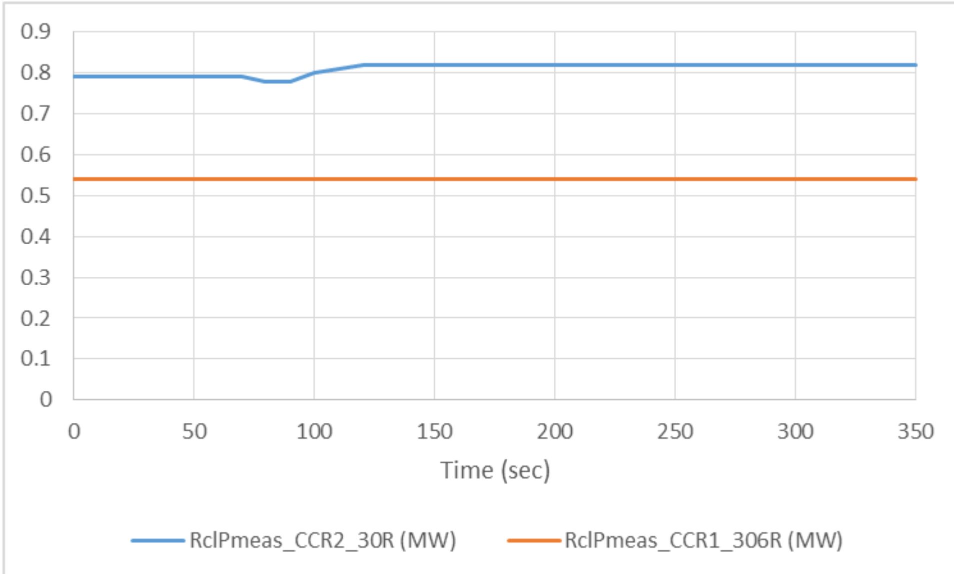


Figure D-124. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.6 Test Case 8.6 Results

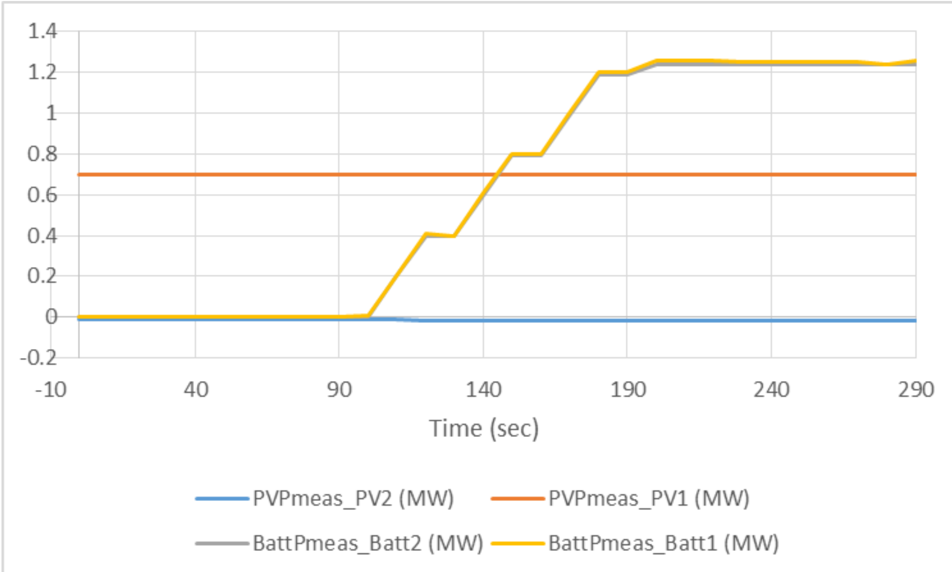


Figure D-125. DER active power flow measurements (MW)

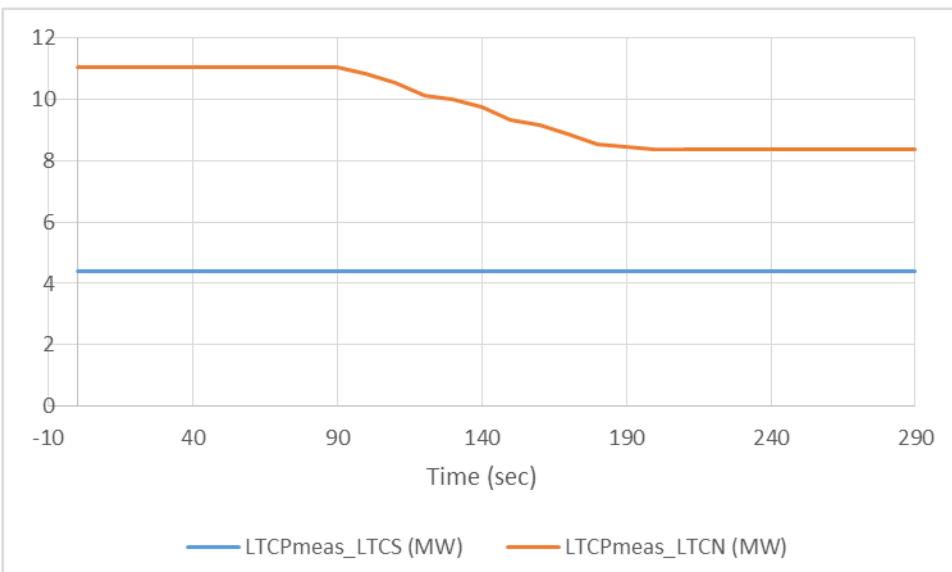


Figure D-126. LTC active power flow measurements (MW)

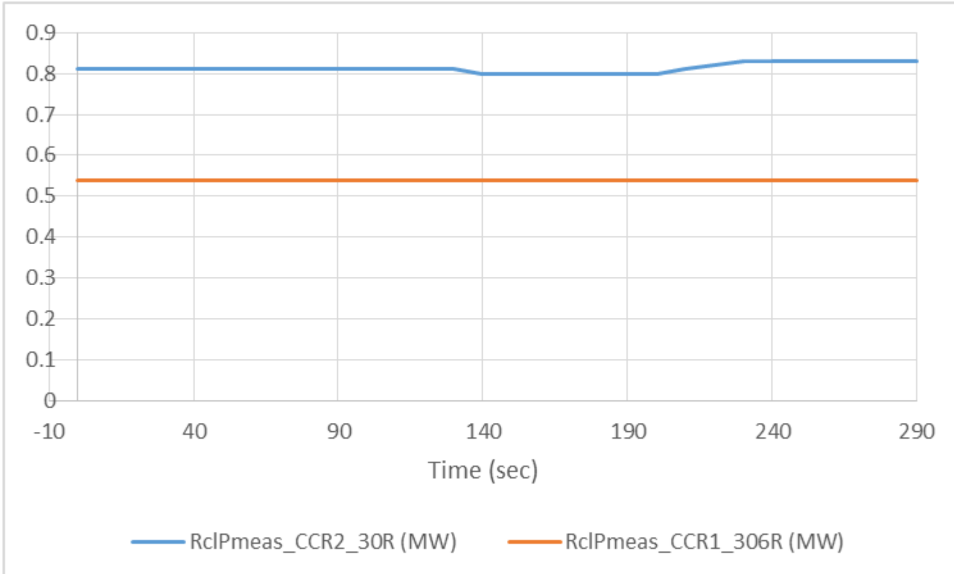


Figure D-127. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.7 Test Case 8.7 Results

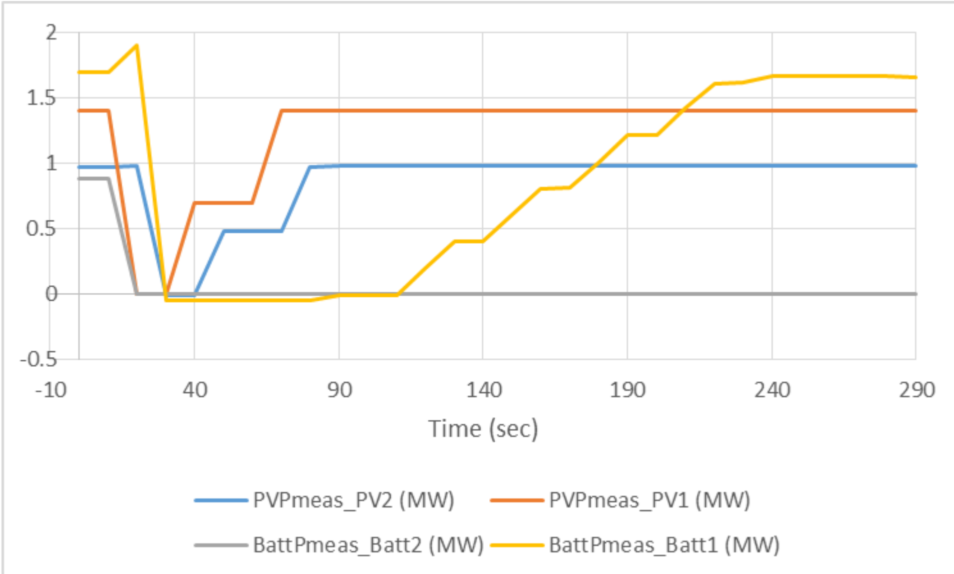


Figure D-128. DER active power flow measurements (MW)

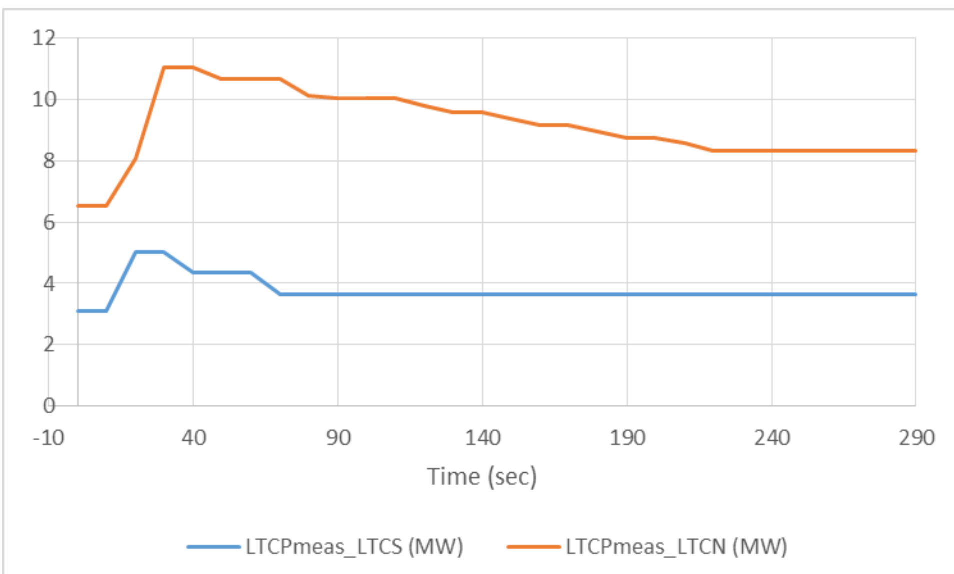


Figure D-129. LTC active power flow measurements (MW)

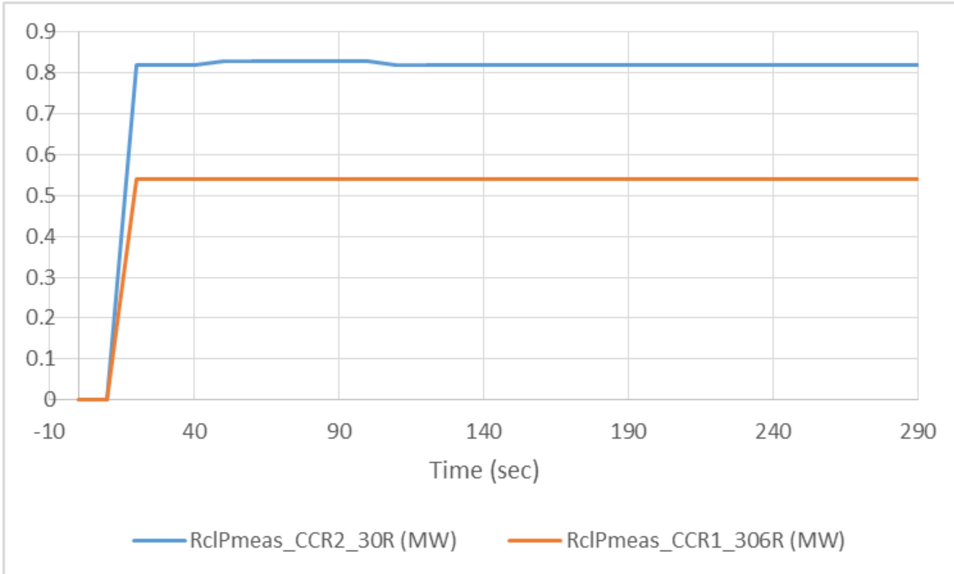


Figure D-130. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.8 Test Case 8.8 Results

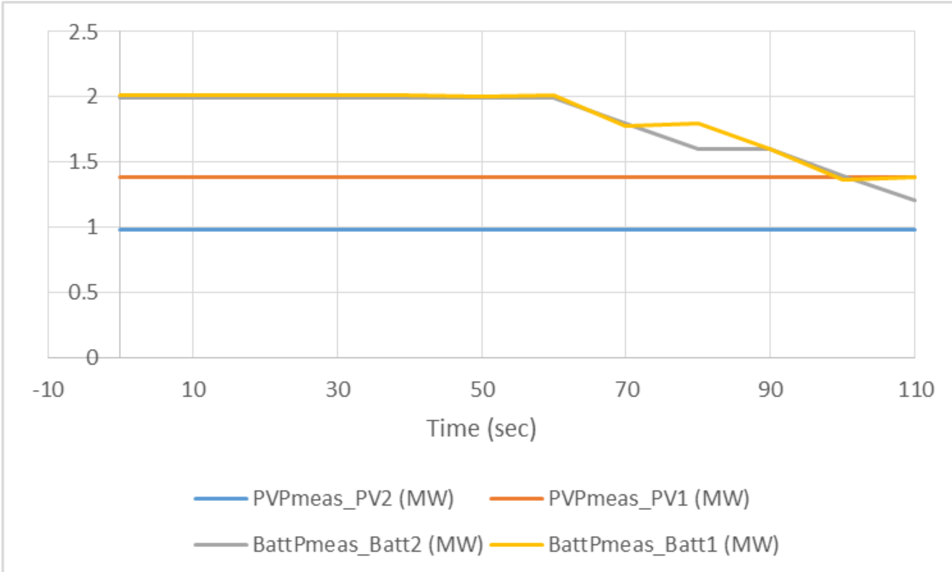


Figure D-131. DER active power flow measurements (MW)

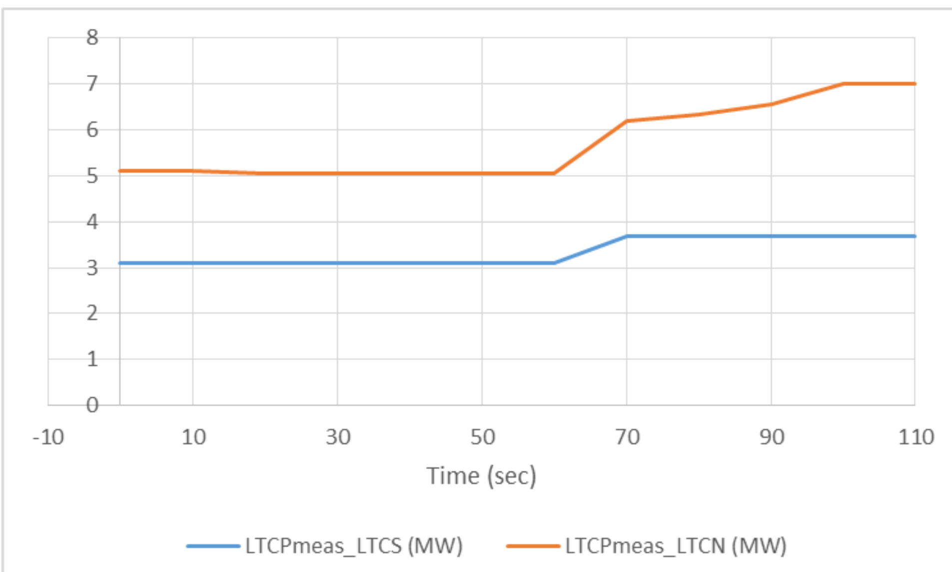


Figure D-132. LTC active power flow measurements (MW)

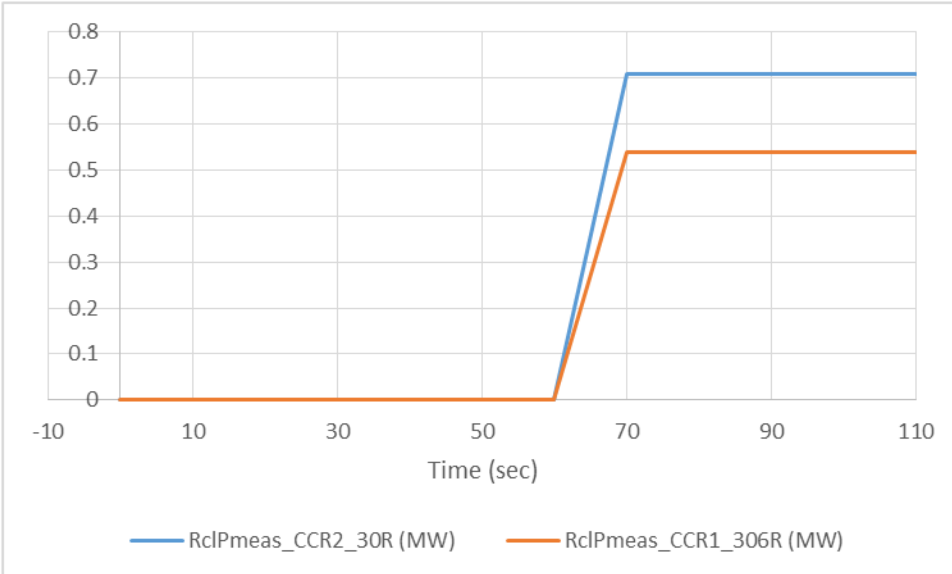


Figure D-133. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.9 Test Case 8.9 Results

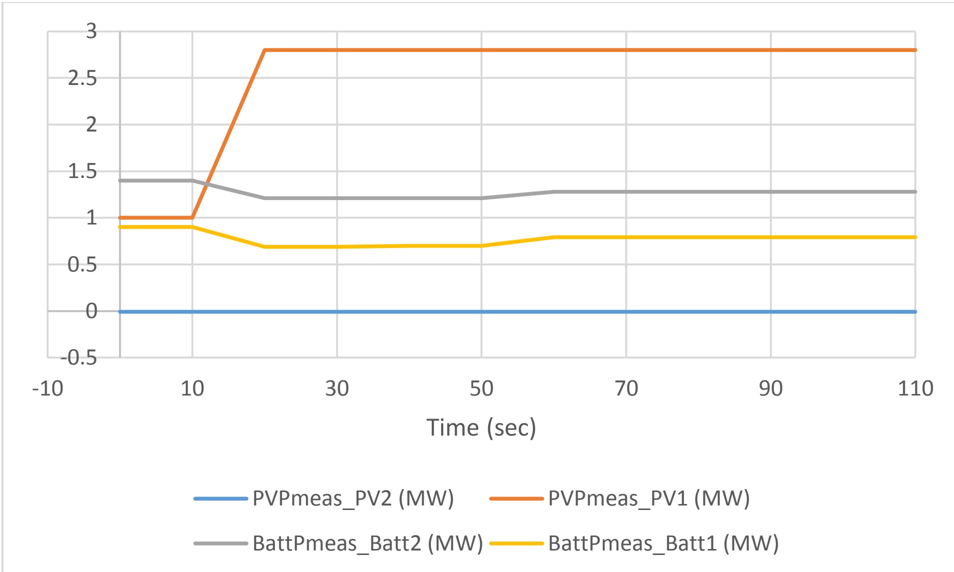


Figure D-134. DER active power flow measurements (MW)

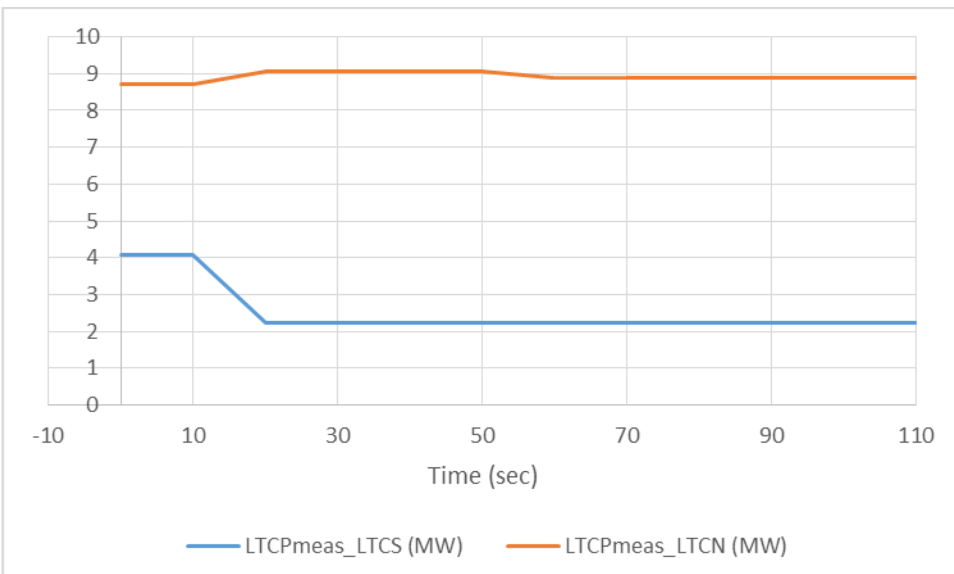


Figure D-135. LTC active power flow measurements (MW)

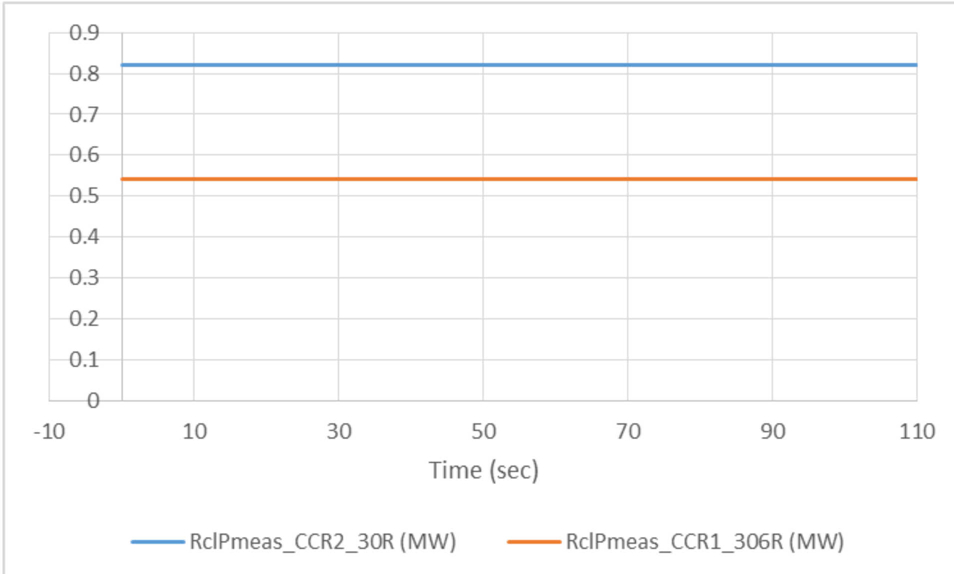


Figure D-136. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.10 Test Case 8.10 Results

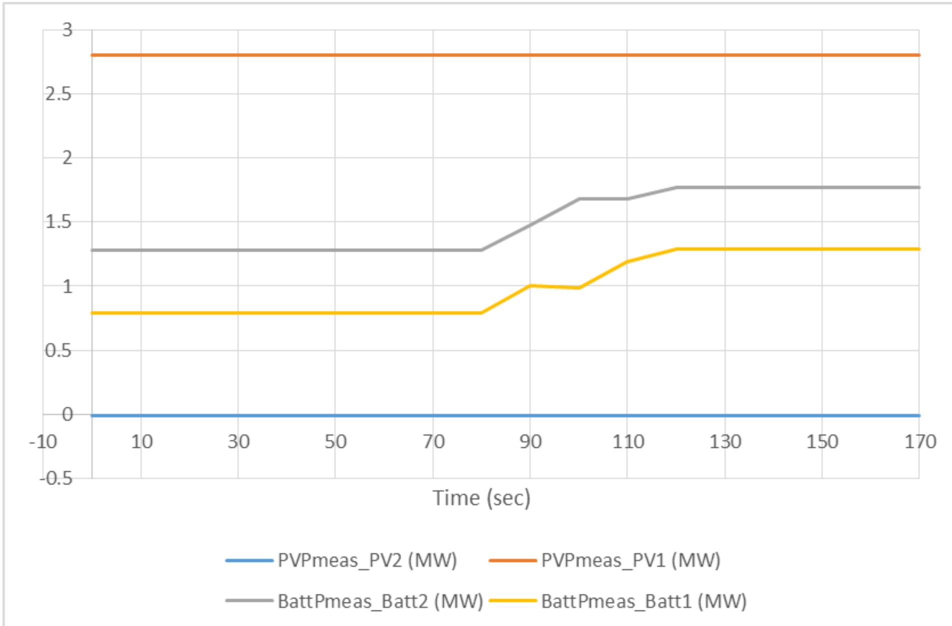


Figure D-137. DER active power flow measurements (MW)

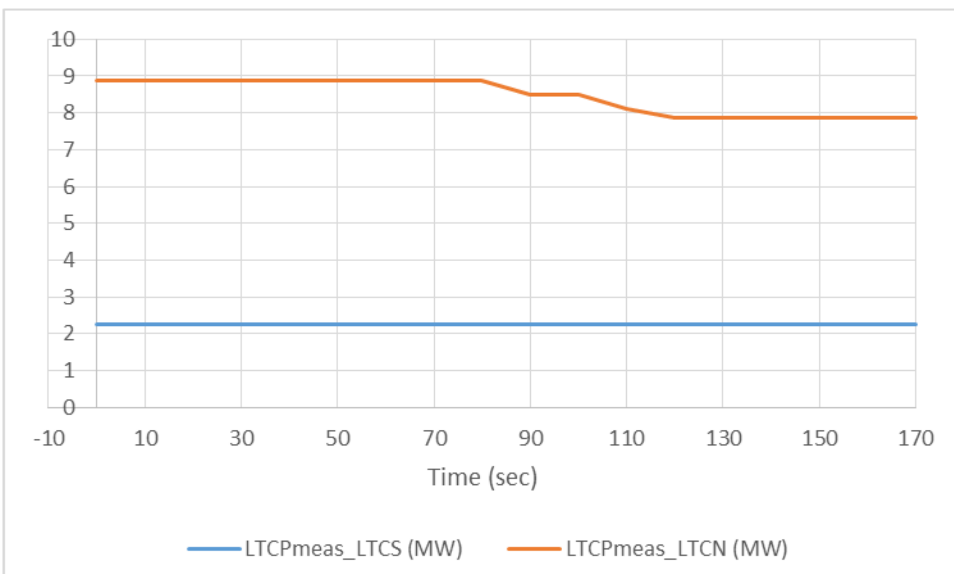


Figure D-138. LTC active power flow measurements (MW)

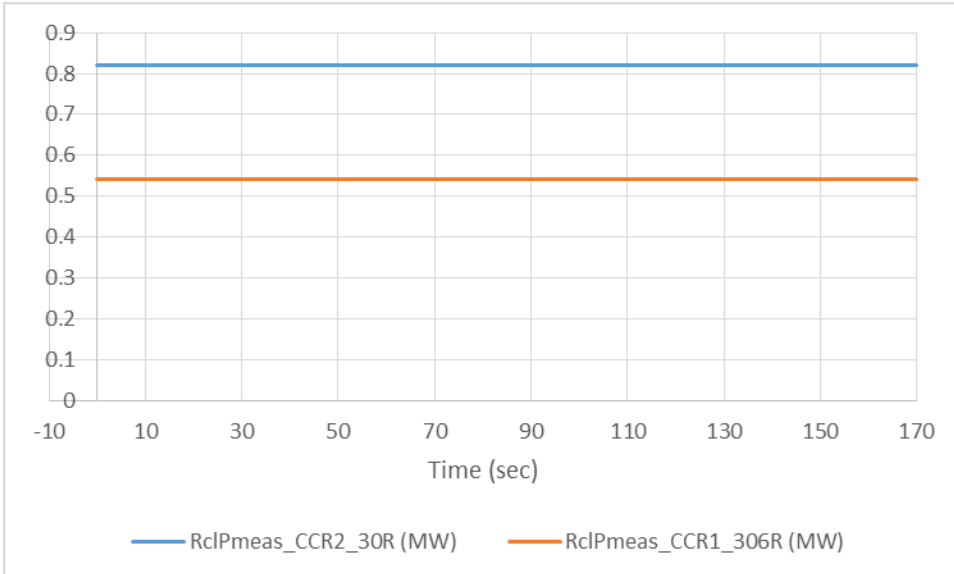


Figure D-139. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.11 Test Case 8.11 Results

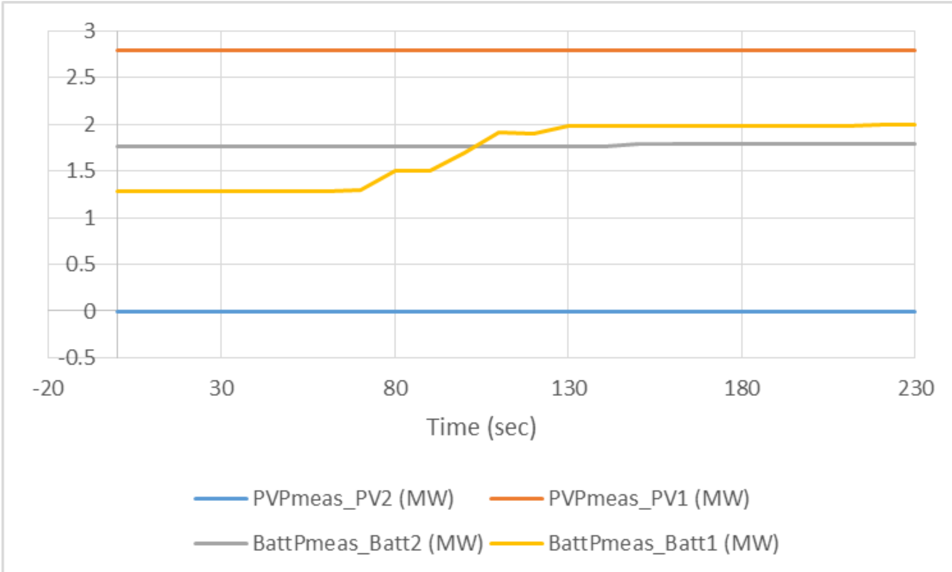


Figure D-140. DER active power flow measurements (MW)

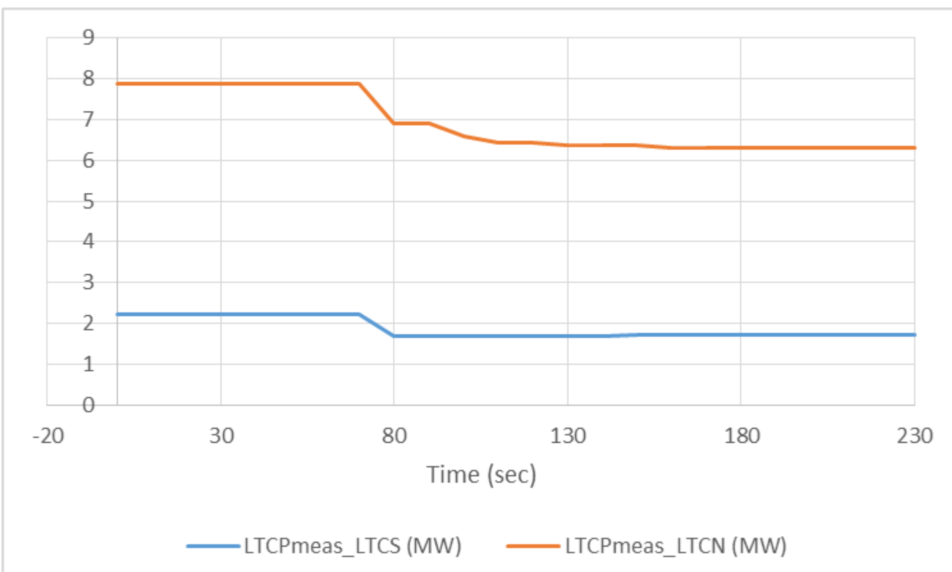


Figure D-141. LTC active power flow measurements (MW)

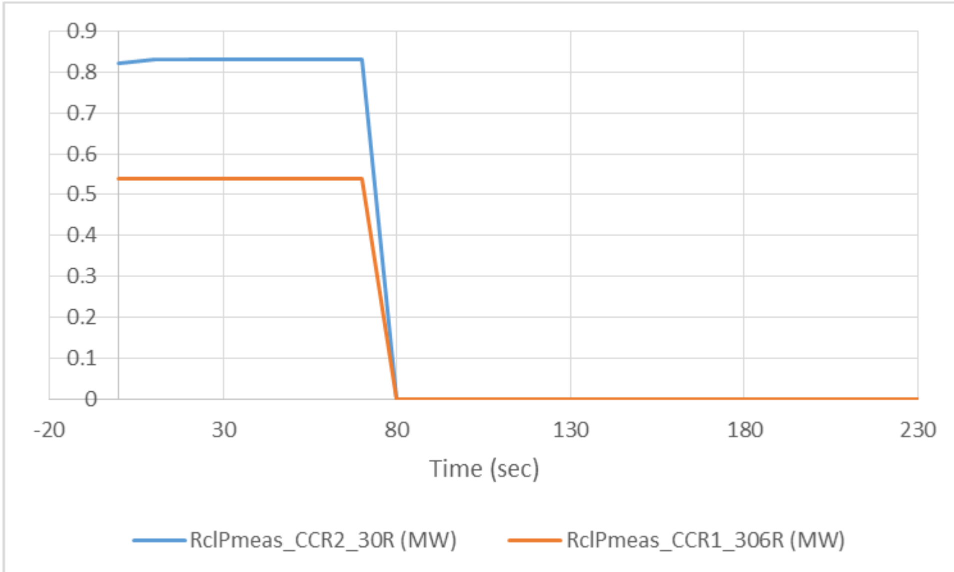


Figure D-142. CCR2_30R and CCR1_306R active power flow measurements (MW)