EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-2, Project 5**
Project Name	**Integration of Customer Systems into Electric Utility Infrastructure**
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Attribution

This comprehensive final report documents the work done in EPIC-2, Project 5.

The project team that contributed to the project definition, execution, and reporting included the following individuals, listed alphabetically by last name.

Internal SDG&E Staff:

Michael Espinoza
Frank Goodman
Kyle Kewley
Zoltan Kertay
Iman Mazhari
William O'Brien
Prajwal Raval
Subburaman Sankaran
Marvin Zavala-Iraheta

Quanta Technology:
Shadi Chuangpishit
Farid Katiraei
Dino Lelic
Baharak Soltani
Mehrdad Yazdanian

Executive Summary

This report outlines the work performed under EPIC-2, Project 5 on Integration of Customer Systems into Electric Utility Infrastructure.

Project Objective and Focus:
The primary objective of EPIC-2, Project 5 was to investigate and address the evolving gateway between customers and utilities to facilitate increase in reliable deployment of clean energy technologies to support distribution systems.

More specifically, the project focus was on performing pre-commercial demonstration of advanced monitoring schemes, root-cause analysis tools, and assessment methodologies for safe and reliable integration and interoperability of customer systems with the distribution system to improve power system operations and thereby increase ratepayer satisfaction and benefits.

Project Approach:
At the early stage of the project work, the project team held a series of meetings and fact finding workshops with various stakeholders from the operation and engineering departments within SDG&E. The main purpose of these sessions was to assess the present stage of monitoring and control system capabilities and to investigate gaps in existing tools and approaches (such as capturing and alarming of fast changing power system phenomena). In parallel, a survey of customer systems and technologies that are being deployed or expected to be integrated into the SDG&E distribution systems was performed. The survey targeted common technologies and customer initiatives to determine potential impact of those technologies on operation practices and integrity of the system.

The outcome of the above investigation and information gathering activities was used to develop functional requirement documents and to describe system specifications for control and monitoring schemes, based on data from phasor measurement units (PMU) in the context of Advanced SCADA Devices (ASD). The new requirements were discussed with both field/substation engineers and distribution operators to ensure they meet the day-to-day system operation needs. A combination of simulated data, historical data, and real-world data streaming, as applicable, was used to calculate indices and validate the analytical methods. Based on the demonstration results, dashboards and requirement documents were revised to reflect the finally agreed list of performance indices and data analytics that would be incorporated in the visualization tool and/or applied automatically in the real-time data processing.

Key Findings and Accomplishments:
The project demonstrated new technologies and analysis methods for monitoring, visualization, and root-cause analysis of distribution systems by using various measurement techniques, data sources and integrating them in one platform to provide a unique monitoring and visualization user experience.

The key system capabilities that were successfully demonstrated and validated were:

- Being able to monitor distribution assets in the field (outside of substations) in real-time, based on measurements received from PMUs, the AMI system, power quality measurement devices, and the SCADA system. The real-time data enabled power quality impact investigations.
- Being able to tap into historical data collected to playback and investigate events over extended periods of time as selected and required by an operator or an engineer. This approach resolved

major issues in previous systems dues to lack of proper time synchronization and difficulty of alignment of the data points from various devices.

- Providing a set of tools for pre/post event analysis based on various data types and sources; this feature was shown to be very effective for root cause analysis, training of operators and engineers, and assessment of operation and design procedures for new technologies and approaches.

As part of the demonstration, it was shown that there are many monitoring features and analysis capabilities that can be added to existing systems to greatly support the needs of operation and engineering users. New capabilities are essential for evaluating system performance and analyzing dynamic events associated with distributed energy resources (DER) and customer-introduced technologies. It was also found that there is a major need for introducing uniformly defined performance indices, monitoring features and power quality indices directly related to assessment of emerging customer technologies, beyond the capabilities of conventional SCADA systems.

Recommendations and Next Steps:

Key recommendations are:

- It is recommended to further validate the use of performance indices introduced in the project and further expand the list, based on proposing new use cases. The project introduced a series of monitoring parameters, operation indicators, and performance indices that can be utilized by system operators and engineers to assess the status of the system, identify the root causes of events, and make informed decisions.
- It is recommended to explore the applications of proposed system indicators and visualization dashboards developed in this project with other stakeholders beyond just distribution planners, protection engineers and system operators. The monitoring approaches have potential to provide detailed data and assessment means for groups such as reliability, substation engineering and automation engineers. Some aspects of the monitoring parameters and indices introduced in this project were unique (such as field total harmonic distortion (THD) measurements and/or use of phase angle in automatic load transfer schemes) and were proven to be very effective in detecting and unfolding the nature of specific fast dynamic events caused by new technologies. However, changes in operating procedures and distribution system standards will be required to bring those features to the real-world applications.
- This project evaluated several new methods of utilizing PMU data and functionalities offered with synchronized data streaming, including the use of analog and digital data transfer channels to monitor and transfer locally measured system parameters such as THD and tap counts. These features are expected to become more beneficial and effective in distribution systems. It is recommended to conduct a business case analysis for the new PMU data applications.

As a next step, it is recommended to provide training on the monitoring and analytical feature of the project to several distribution system operators and field engineers that are involved in day-to-day operation and root-cause analysis of the event to further gather their feedback and to validate the use of performance metrics. The additional discussions will also help develop a strategy and technology roadmap to bring various aspects of monitoring and visualization technologies introduced in this project into production level. This roadmap should address the improvement of the existing platform and application and development of new applications, infrastructure and procedures to bring it to operations and the control room, and to streamline its use by engineering and planning groups.

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ACSR	Aluminium conductor steel-reinforced cable
AL	Aluminium
AMI	Advanced metering Infrastructure
ASD	Advanced SCADA Devices
CB	Circuit Breaker
CBC	Circuit Breaker
CBEMA	Computer Business Equipment Manufacturers Association
DAMD	Distribution Asset Operation monitoring and Diagnostics
DCI	Daily Clearness Index
DER	Distributed energy resources
DERICC	DER Interconnection Compliance
DMS	Distribution Management System
DQV-FM	Data Quality Validation of Field Measurement
DUT	Device Under Test
DVC	Dynamic Voltage Control
DVI	Daily Variability Index
DVR	Dynamic Voltage Regulator
EOLD	Equipment Overloading Detection
EPIC	Electric Program Investment Charge
FE	Frequency Error
FLISR	Fault Location, Isolation and Service Restoration
GIS	Geographical Information System
GUI	Graphic User Interface
HW	Hardware
IEC	International Electro technical Commission
IEEE	Institute of Electrical and Electronics Engineers
ITF	Integrated Test Facility
ITIC	Information Technology Industry Council Curve
IVVC	Integrated Volt VAR Control
KPI	Key performance indices
KW	Kilowatt
LGU	Local Generation Usage
LICFM	Large Industrial Customer Facility Monitoring
LTC	Load Tap Changer
ms	Milliseconds
MVAr	Mega Volt-Ampere Reactive

MW	Megawatt
NIST standard	National Institute of Standards and Technology
NMS	Network Management System
PDC	Phasor Data Concentrator
PMU	Phasor Measurement Units
PQ	Power Quality
pu	Perunit
PV	Photovoltaic
REC	Reclosers
RFE	Rate of Change of Frequency Error
RMS	Root Mean Square
ROCOF	Rate of Change of Frequency
RPM	Reactive Power Management
RTAC	Real-Time Automation Controller
RTDS	Real Time Digital Simulator
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SARFI	System Average RMS Variation Frequency Index
SCADA	Supervisory Control and Data Acquisition
SDG&E	San Diego Gas & Electric
SDGE	San Diego Gas & Electric
SDO	Standards Development Organizations
SEL	Schweitzer Engineering Laboratories
SEMI	Semiconductor Equipment and Materials Institute
TDD	Total Demand Distortion
THD	Total Harmonic Distortion
TVE	Total Vector Error
UPS	Uninterruptable Power System
VAr	Volt-Ampere Reactive
VFD	Variable-Frequency Drive
VPFM	Voltage and Power Flow Monitoring
VR	Voltage Regulators
WTP	Water Treatment Plant

1 Introduction

1.1 Project Objective

The primary objective of EPIC-2, Project 5 was to investigate and address the evolving gateway between customers and utilities to facilitate increase in reliable deployment of clean energy technologies to support distribution systems.

More specifically, the project focus was on performing pre-commercial demonstration of advanced monitoring schemes, root-cause analysis tools, and assessment methodologies for safe and reliable integration and interoperability of customer systems with the distribution system to improve power system operations and thereby increase ratepayer satisfaction and benefits.

To achieve the above objective, the key focus areas were:

- To demonstrate monitoring and visualization schemes for distribution operators, at higher resolutions and with more advanced functionalities as required for capturing and investigating fast dynamics in the system,
- To demonstrate integration and interoperability of customer systems with the distribution system with ability to monitor, visualize and respond to fast phenomena,
- To demonstrate monitoring systems with superior capabilities compared to conventional distribution SCADA monitoring systems, such as:
    - Higher resolutions, higher communication speed, higher bandwidth, and time stamping.
    - Combining multiple sources of data – all with common data format.
- To demonstrate advanced tools and techniques for monitoring and evaluation of customer technology integration.

In addition, the final results and observations from the pre-commercial system were used to provide recommendations for design of the next generation of advanced SCADA systems.

1.2 Issues/Problems Being Addressed

Reliable operation of modern power systems requires close monitoring of the system operating conditions. Until recently, the measurements were only provided by supervisory control and data acquisition (SCADA) system, including power flows and bus voltage magnitudes. Distribution SCADA does not cover all utility assets. As an example, line voltage regulators may not report tap positions or line voltages to SCADA. Conventional SCADA measurements are reported by exception and their time resolution is 1-2 seconds or slower (depending on communications performance and how many data points are pulled in one request).

AMI data recording only provides cumulative energy exchange data (consumption or production) and RMS voltage at 5 to 15 minute intervals at the meter level. Furthermore, AMI devices only monitor secondary systems (downstream of service transformers).

Therefore, fast dynamics and transient phenomena (such as transient switching) and almost any power quality impacts (i.e. harmonics and resonance-based instability) cannot be identified from conventional SCADA measurements or AMI data. In order to address these shortcomings, an enhancement of existing technologies in the area of high-resolution monitoring, advanced visualization and fast controls will be needed to provide adequate tools for operators and system engineers to assess the fast dynamic events.

The deployment of phasor measurement units (PMUs) enables various applications with the use of synchronized measurements. A PMU installed at a node can make direct measurements of the voltage phasor of the bus and the current phasors of some or all its incoming/outgoing branches, based on the PMU available channels.

This project performed the following activities:

- Defining circuit candidate selection criteria and data gathering requirements that can facilitate project objectives in terms of design and development of the advanced monitoring, analysis and visualization
- Planning for the logistical aspects of field data gathering and building into the visualization tools
- Identifying the design and location selection requirements for possible additions to the field device population to increase observability
- Introducing data analytics, evaluation methodologies and metrics to assess the system performance in near-real time
- Laboratory testing and analysis of expected phenomena through simulations
- Evaluation of monitoring and control device capabilities and validation in the laboratory environment
- Enhancement of the visualization tools to incorporate proposed metrics and data analytics
- Preparation of test plans and determination of field conditions/durations for data gathering and demonstration
- Data analysis from the field
- Demonstration of applications and tools that can facilitate safe and reliable operation to mitigate any issue introduced by customer services
- Proposing operator control strategies for managing the circuits and customer systems via SCADA
- Demonstrating the methods through laboratory testing and/or applying in the field and gathering field measurements

In addition, the project incorporated considerations to address requirements to increase the reliability and enhance power quality of services to the customers. Some additional value-added propositions (Metrics) introduced for the project were:

- To expand distribution system control, monitoring and operation capabilities beyond conventional SCADA approaches to gain visibility and control on secondary networks
- To investigate advanced monitoring and visualization practices using high-resolution measurement and data analytics to provide tools and investigation methods for distribution system operators and engineers to capture, examine and react to fast dynamic events
- To facilitate superior customer involvement and deployment of renewable and sustainable technologies by providing the means for investigation of real-world impact of customer systems and high PV penetration cases on distribution system and utility assets
- To prepare requirements and introduced advanced tools for monitoring and visualization of the data and the results, as well as analytical applications for post-processing and performance evaluation in

close to real-time environment to support challenging work load of the system operator in new environment.

1.3 Project Approach

The preliminary part of the project covered the tasks associated with selection of project technical lead, the project team, development of project plan and selection of the contractor.

The technical part of the project was executed in two phases:

- **Phase 1** – Design pre-commercial demonstration system: in this phase of the project, a preliminary analysis was performed to evaluate the likely impacts of customer integration on distribution system operation; the system was characterized for potential targets and the system visualization and analytical applications requirements were identified. Monitoring, control and operation practices in support of customer system installations were developed and in the final stage, a demonstration system was designed.

- **Phase 2 –** Demonstrate an advanced customer integrating and monitoring system: The demo system designed in Phase 1 was implemented and integrated, and a pre-commercial demonstration was done. Based on the test results, the customer system integration was evaluated and a final report was prepared including the analysis results.

1.4 Major tasks, Milestones Achieved and Deliverables Produced

This section provides a detailed description of the work approach and methodology, and the required outcome and deliverables of each task.

The tasks associated with preliminary work were:

Preliminary Phase - Task 1 - Team Formation and Project Plan

The SDG&E EPIC program manager identified the technical lead for the project based on experience and technical expertise. Later, the internal project team was formed by identification of technical skills and expertise available within the organization. After forming the internal project team, the task to develop the project plan was given to the technical lead. The technical lead with the help of the project team wrote the project plan as per the guidance provided by the SDG&E EPIC program manager adhering to EPIC guidelines.

Preliminary Phase - Task 2 - Procurement of Contractor Services

Scope of the work was identified and written for the part of the project needed to be contracted out to engineering consulting firm. Standard company practices were followed for contractor selection.

The tasks associated with technical part of the project were divided in two phases as shown in figure below.

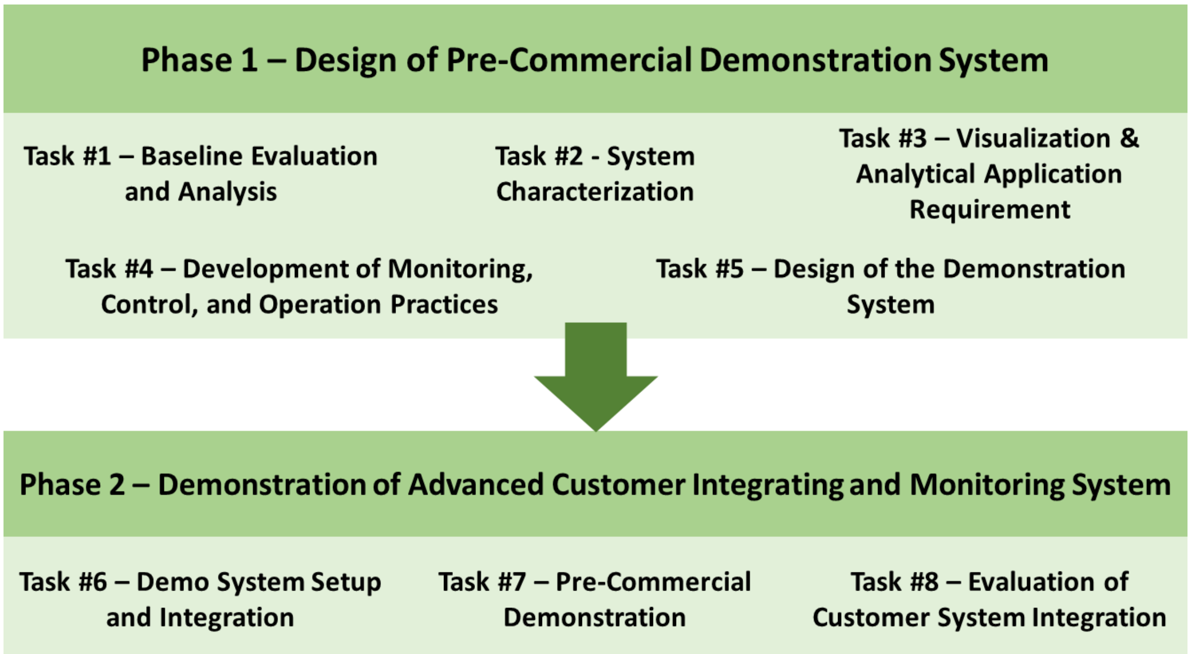

Figure 1-1. Project tasks structure

The following sections provide additional description of the technical part of the work, and details about the accomplishments with regards to the major milestones and deliverables.

1.4.1 Phase 1 – Design of pre-commercial demonstration system

Task 1 - Baseline Evaluation and Analysis

The objective of this activity was to assess the preset state of monitoring and control in distribution systems and analyze the impact of new customer technologies on the system.

A detailed list of activities performed in this task was:

- Performing a survey of customer systems and technologies that are being deployed or expected to be integrated into the SDG&E distribution systems
- Investigating impact on operation practices and integrity of the system due to new technologies and customer initiatives
- Determining the present state of the monitoring and controls, and the level of the visibility into customer systems, including:
    - Distribution SCADA measurement
    - AMI systems and data availability
    - PMU on distribution systems
    - Other sources of measurements
- Investigating the present status of PMU deployment on distribution systems at SDG&E, and select circuits with PMU and communications system in operation as the target circuits for enhanced monitoring and operation analysis. A list of criteria should has been developed for circuit/region selection. Ex-

ample factors in circuit selection were the available level of PV penetration and types of technologies deployed.

The outcome of this task was:

- Baseline review and assessment
- Preparing circuit selection criteria and list of candidate circuits for further analysis, simulation and integration.

Task 2 - System Characterization for Potential Target Circuits

The objective of this task was to evaluate data availability and system coverage from the potential target circuits. The evaluation will be used to proposed additional measurement and/or visualization capabilities to strengthen the visibility and control of the system. The main activities as part of this task were:

- Determine circuit loadings and amount of PV
- Identify the number and locations of PMU devices to determine the circuit coverage
- Prepare a circuit map showing all critical devices and customer installations
- Determine device settings and control modes
- Document any special operating procedures and circuit conditions that can benefit from enhance monitoring and near real-time controls
- Examine access to the devices and their control system connections
- Evaluate PMU data streaming and data availability, and logistic aspects of accessing data
- Examine access to non-PMU data from target circuit locations, including wideband power quality data snapshots and metrics
- Prepare a summary report on what the gaps in the measurement, monitoring and operation are when it comes to awareness and management of customer systems
- Evaluate the data streaming in to PI Historian and any other data warehouses and the linkage among databases

The outcome of this task was:

- Identification of existing data availability and gaps
- Recommendations for additional data requirements.

Task 3 - System Visualization and Analytical Applications Requirements

The task objective was to assess advanced visualization system capabilities, prepare functional specifications and identification of key needed applications and performance indices.

This task was addressed by conducting the following activities:

- Investigation of visualization methods to present the PMU data on circuit maps and to create graphical view of the system events and power quality issues based on performance indices:
    - Evaluating the capability that exists today and what needs to be developed or added to the visualization system,

- Identification of key applications (data analytics, statistical evaluation methods), and set of Key Performance Indices (KPIs) for power quality and operation performance monitoring:
    - Using simulation and/or historical data, as appropriate, to calculate indices and validate the analytical methods
    - Finalizing and documenting a list of performance indices and data analytics that will be incorporated in the visualization tool and/or applied automatically in the real-time data processing

The task outcome was:

- Visualization requirements and description of data processing applications
- Identification of key performance indices and targeted used cases.

Task 4 - Development of Monitoring, Control and Operation Practices in Support of Customer System Installations

This task objective was to propose and develop advanced monitoring and control practices that can close the gaps in the existing operation schemes to expand operator visibility beyond substations to support system impact assessments as part of the customer system integration process. The primary focus was on enhancing the system monitoring and operator's capability to characterize the system dynamics and to provide methods for fast data analysis and event diagnostics. The design incorporated all aspects of: system capabilities, monitoring devices and data capturing and post-mortem analysis. The main activities in undertaking this task were:

- Determining the response requirements and operational practices to support customer systems
- Defining the monitoring requirements and system architecture, including the communications and controls for advancement of system operation
- Investigating capabilities of commercially available sensors, power quality and/ revenue metering devices, and phasor measurement units (stand-alone or as part of other IEDs) that can provide high resolution data measurement and power quality data capturing and transient event recordings, such as:
    - Voltage and current phasors
    - Power flow (active and reactive)
    - Frequency tracking and reporting rate of change of frequency (ROCOF)
    - Harmonics and THD/TDD measurements
    - Fast transients
    - System status information, including switch position, voltage regulators tap positions, and
    - Circuit connectivity information
- Evaluating product capability documents from vendors; or perform laboratory tests on selected measurement devices (sensors, IEDs, PMUs) to determine accuracy, measurement resolution and quality and type of measurement data such as transient events, to understand and document expected device performance
- Defining PMU requirements specific to distribution systems
- Developing settings and configuration files for the devices in the field to support project data gathering and device control needs

- For cases of inadequate device capability and/or coverage, propose temporary methods and devices to be incorporated in the real-time simulation environment to supplement the existing devices and data coming from the field for the purpose of evaluating the tools under investigations.

The task output was:

- Outlining of the design and needed system development for the advanced monitoring, control and operation
- Evaluating the capabilities of selected devices (sensors, IEDs, PMUs) to measure transient events and power quality
- List of data and measurement points as the basis for the simulation system design.

Task 5 - Design of the Demonstration System

This task objective was to develop detailed plan and infrastructure for the demonstration system requirements for the purpose of verifying the advanced monitoring, visualization and customer integration practices. The design of the proposed demo system included:

- Demo system architecture incorporating both the field measurements and monitoring and the interfaces to a real-time simulation environment in the laboratory to provide additional data in support of full realization of the analytical schemes
- Documenting the requirements for demonstration system design
- Use cases for the customer system integration demonstration
- Identifying proper control algorithms for enhancing the safety and reliability of the system (control system validation will be performed on the real-time simulator)
- Integrating with existing monitoring and controls in the field to develop demo system platform
- Preparing high level interface descriptions for the proposed demo system.

The task output included:

- Demonstration system specifications
- Demonstration system implementation and field integration plan.

1.4.2 Phase 2 – Demonstration of Advanced Customer System Integration

Task 6 – Demo System Setup and Integration

This task was about implementation of the demonstration system that incorporates both remote monitoring and control of the selected devices on the SDG&E Distribution systems, as well as the real-time simulation of the same system in the laboratory environment for capturing and transferring additional measurement data to the visualization system and operator screens.

As part of this process the following sub-tasks were executed:

- Determination of type and availability (accessibility through remote control) of field power apparatus and emerging technologies (smart PV inverters, Dynamic VAR Controllers, BESSs. Electric vehicles, building automation and demand response programs) associated with the customer systems that can be incorporated in a demo system

- Determination of SCADA based control schemes (such as voltage/VAR control, fault locators, automatic load transfer schemes) on the selected circuits that can be used to create various pre-specified system changes and realistic operating scenarios:
    - Change in voltage profiles through LTC at the substation or at cap banks
    - Interaction with circuit device operation (load transfer, operator controlled voltage and VAR optimization a few times per day)
    - Control and dispatch of Dynamic VAR Controllers
    - Change in PV system production according to time of day and season
- Utilizing real-time simulation models for the part of the system that is simulated for additional data gathering and monitoring support:
    - The model incorporated customer systems and interfaces for capturing data and characterizing the impacts on the distribution system
    - The model needed to reflect similar field devices and feeder level controls associated with SCADA or existing localized (automatic) control to execute and investigate interaction of typical operator controls with those of the customer system controls
- Incorporating additional measurement devices as required and identified in a supporting role:
    - Selecting devices based on the results of device evaluations and specifications
    - Integrating devices in the demo system and program them.
    - Preparing settings and configuration files
- Providing means of data streaming and capturing in the simulation and field data in PI historian as infeed to the visualization tool:
    - Visualization tool is primarily driven by field data measurement
    - Measurements from the real-time simulator to be provided as a secondary infeed to fill out the gap in field data monitoring
- Verifying the enhancement of the visualization and monitoring tools:
    - Evaluating the visualization tools based on the data inputs and key performance indices identified as part of the design stage.
- Verifying and preparing the hybrid demonstration system for the demo, consisting of the field data, real-time simulation data and visualization tool

The task output included:

- Demonstration of the system setup integration
- Successful setup of the demonstration system
- Training of the SDG&E internal project team on utilization of the demonstration system.

Task 7 – Pre-commercial Demonstration

This task involved development of test plan and schedule for testing, as well as performing the demonstration tests. The main activities were:

- Detailed plans for each of the tests to be run, including identification of the objectives of the tests, use cases under investigation, test methodologies, information to be captured, Contractor's staff, system/equipment, SDG&E lab system/equipment required, circuit models required, and contractor and SDG&E project team support needed for specific items
- Methodology for capturing test data and comparing with simulation data

- Decision points at which preliminary data assessment is used to determine if more test iterations or alternative new test cases should be run
- Simulating scenarios and test cases in the laboratory environment
- Collecting live data streams as well as the output from the visualization tools
- Creating transient events and outages associated with customer systems to determine operator responses and to demonstrate how the visualization system will be used for post-mortem analysis
    - Root cause investigation of the failure and outage
- Performing data analysis and documenting test results and observations
    - Collecting test data and results for the report
    - Collecting event and operating records from field devices

The output for this task included:

- Test plan and schedule
- Test results
- Root cause investigation approach
- Analysis of test results
- Analysis methods for determining benefits of the advanced visualization schemes and lessons learned.

Task 8 – Evaluation of Customer System Integration

The objective of this task was to identify and describe system improvements obtained by introducing advanced monitoring and customer system integration schemes demonstrated in this project. The results from the system demonstrations and test cases were utilized to analyze and propsoe standard practices for the customer integration and system monitoring tools. The main activities as part of the system evaluation and standardizations were:

- Determination of data accuracy and possible or expected errors in live streaming and/or event captures
    - Utilizing sample data from various devices in the field
    - Comparing data sources and calculate percent error
    - Using laboratory testing of the specific devices, as needed to verify percent error and/or potential sources of error
    - Calculating level of offset in measurements
    - Investigating calibration and correction methods
- Analyzing data to determine issues and possible adverse impacts on circuits, equipment, and customers. Summarizing observations in relationship to correlated events and conditions:
    - Voltage profiles
    - Losses and reactive power profile
    - Power flow including reverse flow
    - Interactions among circuit devices and control systems
    - Effect of PV penetration, based on changes in the level of PV production versus load at various time intervals
    - Changes in the waveform distortion or harmonic content of voltages and currents
    - Power device operation and status changes, including wear or stress impact
    - Identify improvement opportunities
- Preparing guidelines for addition of new sensors and measurement device installations

- Determination of minimum number of measurement points and locations on the system to install sensors and meters
- Defining device specifications and functional requirements to support advanced monitoring and integration of the customer systems
- Defining communication needed for capturing and data streaming from the measurement point
  - Determination of minimum communication infrastructure requirements, such as data bandwidth needed, minimum required speeds for the data transfer, and list of use cases for those data transfer needs.
- Determination of requirements for visualization and operator interface to support customer systems.

The task output included:

- Tool and application evaluation
- Requirements for new systems

Task 9 – Comprehensive Final Report

This task incorporated the work on preparing the final report for the project, which is a comprehensive record of the work completed, findings, and recommendations. The report was intended to enable stakeholders to understand and use the project's output.

2 System Requirements and Evaluation

This section outlines the outcome of system requirement investigation, test system development and evaluation of the functionalities, using both real-world data (from devices deployed in the field) and simulated data (from test setup in the laboratory environment).

2.1 Survey of Customer Systems and Their Impact on the Distribution Systems

Prior to developing the functional requirement for the test system, a survey of customer technologies was performed. The survey incorporated common technologies that are presently installed by customers and integrated into utility grid (such as roof-top solar systems), as well as the technologies that are expected to be introduced and become mainstream, such as Electric Vehicle Charging Stations (EVCS), and behind the meter hybrid energy storage systems. Technology characteristics and impact on distribution systems from the perspective of day-to-day operation were analyzed. Common measurement and performance indices were also introduced to characterize their power exchange with the grid and to quantify their contribution in affecting power quality of the system.

2.1.1 List of Customer Systems and Technologies

One of the Tasks on the project was to assess the present state of monitoring and controls and to analyze the impact of new customer technologies on the distribution systems. Extensive research was performed to determine a list of customer systems and technologies that are being deployed or expected to be integrated into utilities' distribution systems. Potential impacts on operation practices and integrity of the system due to those new technologies have been also investigated.

The following list provides the identified customer systems and technologies that are being deployed or expected to be integrated into the distribution systems in the next 2-5 years:

- Roof top PV systems (< 50 kW) – with micro inverters, and mostly residential systems;
- Roof top PV systems (< 50 kW) – with string inverters, and mostly residential systems;
- Roof top PV systems (< 1 MW) on commercial buildings, such as warehouses or large department stores;
- Ground mounted PV systems that are privately owned;
- Electric Vehicle charging stations, level 2 or fast chargers;
- Fuel Cell Systems (> 100 kW, for industrial facilities);
- Residential Energy Storage Systems (< 10 kW, 2-4 hrs.);
- Community Energy Storage Systems (50 kW to 500 kW, 2-4 hrs.);
- Commercial Energy Storage System (50 - 500 kW, 2-4 hrs.);
- Traction systems (electric train or autobus) with AC interface;
- Dynamic Voltage Control (DVC) (1MVA+) that may be used in conjunction with large PV plants
- Secondary voltage control devices, by utilizing power electronic systems that can provide voltage regulation and reactive power compensation downstream of service transformers,
- Variable Frequency Drives (VFDs), and
- Customers with non-linear loads such as Arc Furnace, or large motor loads without VFD.

2.1.2 Impact Categories

The impact of identified new technologies on distribution systems was investigated and summarized. The potential impact categories are listed below:

- Overvoltage issues
- Under voltage issues
- Voltage ring down (damped voltage oscillation)
- Transformer overloading issues
- Distribution system loss increase
- Extensive reverse power flow
- Increased number of tap operations in voltage regulators and load tap changers
- Increased number of switched capacitor operations
- Changes in short circuit capacity of distribution systems which in turn affects the rating of equipment (e.g., circuit breakers, switches, etc.)
- Deterioration of protection system coordination
- Increased chance of incidental faults
- High frequency switching transients - that can cause resonances or increase losses
- Load imbalance increase
- Ground fault over voltage phenomena
- Increased risk of apparatus failure
- Increased risk of cable failure
- Increased risk of unplanned islanding
- Harmonics
- Voltage flicker.

2.1.3 Key Performance Indices for Quantifying System Performance and Imapcts

In order to identify and monitor each impact category or distinguish events, various measurements, indicators and indices are required to associate causes with an effect. It was assumed that various type of measurements are gathered and available from metering devices or specialized Intelligent Electronic Devices (IEDs) across the circuits. Collected measurements were processed to create indictors and performance indices which are informative of system conditions and any potential events.

The proposed measurements, indicators and key performance indices (KPIs) that were considered for identifying and classifying specific events are listed as follows:

Measurement type parameters:

- Voltage magnitude,
- Voltage phase angle,
- Current magnitude,
- Current phase angle,
- Active power (from load),

- Active power (from PV systems or various DERs),
- Reactive power (from load, generation, or passive shunt capacitive/reactive elements, and static compensators),
- Tap Position & capacitor/reactor status,
- Power frequency.

Indicator type parameters:

- Voltage trends,
- Phasor diagrams,
- Rate of change of frequency (ROCOF) trend,
- Harmonic histograms,
- Odd/even harmonics spectrum,
- Symmetrical component plots,
- Vector jump plot,
- Neutral voltage shift plot,
- Short duration transients (cycle by cycle event record).

Key Performance Indices (KPIs):

The main KPIs used in the project were:

- Voltage Swell (SARFI-110) [1]
- Voltage Sag (SARFI-80, SARFI-90) [1]
- SARFI-SEMI [1]
- SARFI-ITIC (CBEMA) [2]
- Harmonic indices such as: TDD, THD [3]
- K-factor (transformer derating) [4]
- Crest factor (distortion factor) [5]
- Voltage unbalance factor [5]
- Flicker factor (short term) [4]
- Flicker factor (long term) [6]
- Solar intermittency factors, such as: DCI and DVI [7]
- Reliability indices such as: SAIDI, SAIFI, CAIDI, and CAIFI [8].

Table below provides the list and definition of the KPIs.

Table 2-1. Key Performance Indices Considered on the Project

Index	Key Performance Index Definition
SARFI-80	Count or rate of voltage sags with retained voltage above 80% of voltage refere
SARFI-90	Count or rate of voltage sags with retained voltage above 90% of voltage refere
SARFI-110	Count or rate of voltage swells with retained voltage above 110% of voltage ref
SARFI-SEMI	Count or rate of voltage sags and interuptions with reatined voltage and duration below the ITI(CBEMA) Curve.
SARFI-ITIC (CBEMA)	Count or rate of voltage sags and interuptions with reatined voltage and duration below the lower portion of the SEMI F47 Curve.
TDD (Total Demand Distortion)	$TDD_I = \frac{\sqrt{I_2^2 + I_3^2 + I_4^2 + I_5^2 + \ldots}}{I_L}$
THD (Total Harmonic Distortion)	$THD_I = \frac{\sqrt{I_2^2 + I_3^2 + I_4^2 + I_5^2 + \ldots}}{I_1}$
K factor (Transfromer derating)	$\left(\sum_{h=1}^{\infty} h^2 I_h^2\right) / \sum_{h=1}^{\infty} I_h^2$
Crest factor (Dielectric stress)	V_{peak} / V_{rms}
Voltage unbalance factor	$\lvert V_- \rvert / \lvert V_+ \rvert$
Flicker factor	$\Delta V / \lvert V \rvert$
DCI	Daily Clearness Index $= \frac{\text{Measured Solar Insolation}}{\text{Calculated Clear Sky Solar Insolation}}$
DVI	Daily Variability Index $= \frac{\text{Length of measured irradiance plot}}{\text{Length of clear sky irradiance plot}}$
CAIDI	Customer Average Interruption Duration Index $\text{CAIDI} = \frac{\sum \text{ Customer Minutes of Interruption}}{\text{Total Number of Customers Interrupted}}$
CAIFI	Customer Average Interruption Frequency Index $\text{CAIFI} = \frac{\sum \text{ Total Number of Customer Interruptions}}{\text{Total Number of Distinct Customers Interrupted}}$
SAIDI	System Average Interuption Duration Index $\text{SAIDI} = \frac{\sum \text{ Customer Minutes of Interruption}}{\text{Total Number of Customers Served}}$
SAIFI	System Average Interuption Frequency Index $\text{SAIFI} = \frac{\sum \text{ Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}}$

Table 3-2 summarizes the correlation between the new technologies identified in the survey and their impacts on the distribution system.

The severity of each technology on the events and impacts is organized as low, medium and high. The measurements, indicators and indices required for identifying and monitoring the impacts or events are also listed in the table.

Table 2-2. Summary of New Technologies, Their Impact, and Parameters Utilized to Characterize Impacts

		Event Types and Expected Adverse Impact on Distribution System Operation																	
		Over voltage	Under voltage	Voltage ring down	Over loading	Loss increase	Reverse Flow	Extensive Tap / Cap operation	Change in the SSC (change in the breaker rating, switch rating, etc.)	Change in protection coordination	Incidental fault	Switching transient	Load imbalance	GFOV	Risk of apparatus failure	Cable Failure	Unintentional Islanding	Harmonics	Flicker
Customer systems	Roof top PV (< 50 kW) - micro inverters	Low		Low	Low	Low	Low	Low	Low	Low	Low	Low	Low	Low	Low	Medium	Low	Low	Low
	Roof top PV (< 50 kW) - string inverters	Medium		Medium	Medium	Low	Low	Medium	Low	Low	Low	Medium	Low	Low	Low	Medium	Low	Low	Medium
	Roof top PV (< 1 MW)	High		High	High	Medium	High	High	High	High	High	High	High	High	High	High	High	High	High
	Ground mounted PV	High		High	High	Medium	High	High	High	High	High	High	High	High	High	High	High	High	High
	Electric Vehicle Chargers		Medium		High	Medium		Medium				High	Medium		High	High		Medium	
	Fuel cell (> 100 kW, Industrial facilities)	Medium		Medium	Medium	Low	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium	High	Medium	Medium	Medium
	Residential ESS (< 10 kW, 2 hrs.)				Low	Low	Low		Low	Low	Low	Low	Low	Low	Low	Medium	Low	Low	
	Community ESS (< 50 kW, 2 hrs.)				Medium	Low	Medium		Medium	Medium	Medium	Medium	Medium	Medium	Medium	High	Medium	Medium	
	ESS (> 50 kW)				High	Medium	High		High	High	High	High	High	High	High	High	High	High	
	Traction system		High		High	High		High				High			High	Medium			
	Dynamic Voltage Control (DVC) (1MVA+)			Low								High	Medium		Medium	High			
	Secondary voltage control device (Grid Co, Grid Bridge, Varentec, DVI, ...)			Low								High	High		Medium	Medium			
	Large industrial loads (nonlinear)		High		High	High						High	High		High	High		High	
	VFD and Arc Furnace		Medium	Low	Medium	Medium						Medium	Medium		Medium	High		Medium	
Measurements	Voltage magnitude	M	M	M		M	M		M		M	M		M	M	M	M		M
	Voltage angle					M	M								M	M	M		
	Current magnitude				M	M	M		M	M	M							M	
	Current angle					M	M												
	Active power				M	M	M			M			M		M	M			
	Reactive power				M	M	M						M		M	M			
	Tap Position & Cap status							M											
	Frequency																M		
Indicators	Voltage trends	I	I	I	I	I	I		I		I	I		I	I	I	I		I
	phasor diagram	I	I	I		I	I		I	I	I		I	I	I	I	I		
	Rate of change of frequency (ROCOF)											I					I		
	harmonic histograms											I							
	odd/even harmonics																	I	
	symmetrical components												I						
	Vector jump											I							
	Neutral voltage shift								I		I			I					
	short duration transients											I		I					I
Key Performance Indices (KPIs)	Voltage Swell (SARFI-110)	x					x							x			x		
	Voltage Sag (SARFI-80, SARFI-90)		x	x													x		
	SARFI-SEMI		x	x													x		
	SARFI-ITIC (CBEMA)		x	x													x		
	TDD											x						x	
	THD											x						x	
	K-factor (utilization)				x		x												
	crest factor (distortion factor)	x	x	x										x					
	Voltage unbalance factor												x						
	Flicker factor (short term)																		x
	DCI	x					x												x
	DVI	x					x												x
	Flicker factor (long term)																		x
	SAIDI														x	x			
	SAIFI														x	x			
	CAIDI														x	x			
	CAIFI														x	x			

2.2 Baseline Evaluation and System Characterization for Potential Targeted Circuits

The objective of this task was to assess the present state of monitoring and controls and to analyze the impact of new customer technologies on the distribution systems. In order to develop monitoring and visualization for current distribution network, it was of great importance to conduct a baseline analysis of the system and evaluate the gaps between current and required state of monitoring.

The baseline analysis was conducted for five selected circuits within SDG&E distribution systems. The baseline analysis focused on the loading conditions of the circuits, the customer PV integration along the circuits and the existing PMU locations of the circuit. The baseline analysis provided an insight into the amount of PV generated and its distribution along the circuit and how effective the existing PMUs can monitor and capture the impacts of PV integration into the distribution circuit.

A detailed set of PMU placement criteria for distribution systems has been then discussed in next step to provide full coverage of the circuit and key locations of interest. Considering distribution PMU installation costs, the communication system availability and/or cost and the practical constraints, the optimal placement of PMUs is an essential task, involving both application assessment and economic justifications (business case). In this section, the PMU placement criteria in general has been investigated and prioritization method has been discussed. Furthermore, these criteria have been tailored for specific applications, for this project.

2.2.1 Circuit Selection Criteria for Baseline Analysis

In selecting the five distribution circuits both technical and practical aspects were considered. The criteria included:

- Presence of medium to high levels of PV integration to the circuit,
- Existing PMU devices in operation in the field,
- Potential distribution assets to be monitored and visualized (including line reclosers, capacitor banks, voltage regulators and similar devices),
- Availability of a real time digital simulation model (RTDS model) of the circuit (based on the SDG&E Library of circuit models) , to facilitate laboratory investigations
- Focusing on circuits that were not investigated recently in similar EPIC studies.

Table 3-3 summarizes characteristics of selected circuits and their device status, including number/amount of PV installed, number of major components (switched capacitors, tie switches, reclosers and voltage regulators), number of field PMUs and loading conditions. In the following sections, the selected circuits have been investigated more elaborately.

Table 2-3. Summary of Selected Circuit Status

Substation	Sub 1	Sub 2		
Circuits	Circuit 1	Circuit 2	Circuit 3	Circuit 4
Total No. of Tie Switch	1	0	3	0
No. of PVs	246	76	81	82
Installed PV capacity (kW)	4604.705	1015.96	652.026	1364.816
No. of Storage	0	0	0	0
No. of Voltage Regulators	6	1	2	1
No. of Switched Capacitors	1	1	2	3
No. of Reclosers	6	2	3	2
No. of field PMUs	12	4	8	2
Installed storage capacity (kW)	N/A	N/A	N/A	N/A
Large DERs (>500 KW)	2	0	0	1
Daytime Peak load (MW)	6.6	4.272	3.24	3.264

2.2.1.1 Example of Baseline Analysis for Circuit 1

2.2.1.1.1 Loading Conditions

The 2016 load data from SCADA has been analyzed and the results are summarized in Table 3-4. In addition to minimum and maximum load, data has been analyzed for minimum and maximum daytime load during the noon time (i.e. 11:00 am – 2:55 pm). The data has been collected based on a 5-minute resolution for 2016 year-around.

Table 2-4. Circuit 1 Loading Condition

Load	Date Time	MW	MVAR	Percent Load	Ia (A)	Ib (A)	Ic (A)	BRKR Status
Minimum load	3/6/2016 13:00	-0.312	0.072	2.30	11.4	12.6	13.8	CLOSE
Maximum load	9/26/2016 18:20	7.992	3.252	71.81	353.4	416.4	438	CLOSE
Average load	--	3.417	0.734	--	--	--	--	--
Min daytime load	3/6/2016 13:00	-0.312	0.072	2.30	11.4	12.6	13.8	CLOSE
Max daytime load	9/27/2016 14:55	6.6	3.492	60.9	315.6	349.8	368.4	CLOSE

Due to PV generation in the circuit, the gross load would be calculated as the difference of the total load and the PV generation.

Thermal Rating

In this section, the thermal rating (ampacity) of all major equipment including reclosers, capacitors, regulators and cables have been summarized and the thermal rating of different sections on the circuit has been determined. Different sections of the circuit (main branch, branch 1 and branch 2) have been marked on Figure 3-1. Table 2-5 shows the ratings of different devices located on different sections of the circuit (main branch, branch 1 and branch 2) and

Table 2-6 shows the rating of all conductors along the different branches of the circuit.

Table 2-5. Thermal Rating of Major Equipment on Circuit 1 (SDG&E data from SynerGI model)

Main Branch					
#	Name	Device Type	Manufacturer	Section ID (Node number)	Rating (Amps)
1	C1-22R	Recloser		C1_360492_MC	630
2	C1-10R	Recloser		C1_357284_MC	630
Branch 1					
#	Name	Device Type	Manufacturer	Section ID (Node number)	Rating (Amps)
1	C1-18R	Recloser		C1_605304_MC	630
2	C1 - 1228CW	Cap		C1_1793943_MC	
3	C1-838G	Regulator		C1_199701_OH	200
4	C1-33R	Recloser		C1_359640_MC	630
5	C1-1224G	Regulator		C1_200233_OH	200
6	C1-1020G	Regulator		C1_500322_OH	200
Branch 2					
#	Name	Device Type	Manufacturer	Section ID (Node number)	Rating (Amps)
1	C1-26R	Recloser		C1_1446954_MC	630
2	C1-1334G	Regulator		C1_467252_OH	200
3	C1- 1340CM	Cap		C1_355049_MC	
4	C1- 1225G	Regulator		C1_203961_OH	200
5	C1-1045R	Recloser		C1_2302813_MC	800
6	C1-1116G	Regulator		C1_200449_OH	200

Table 2-6. Thermal Rating of Conductors along Circuit 1 (SDG&E data from SynerGI model)

Main Branch		
#	Conductor Type	Rating for load calculating (Amps)
1	1000 XLPECN-PEJ AL	580
2	636 ACSR	770
3	336.4 ACSR	530
Branch 1		
#	Conductor Type	Rating (Amps)
1	3/0 ACSR	300
2	336.4 ACSR	530
3	#2 5005	185
4	#2 ACSR	180
5	#4 B.STRD	180
Branch 2		
#	Device Type	Rating (Amps)
1	336.4 ACSR	530
2	1000 XLPECN-PEJ AL	580
3	#2 ACSR	180
4	#2 5005	185
5	#6 B.STRD	130
6	#4 B.STRD	180

Based on the provided data, the thermal rating of each section would be the minimum rating of all devices in that section. Therefore, the thermal rating for main branch, branch 1 and branch 2 would be **530 Amps**, **180 Amps** and **130 Amps,** respectively.

2.2.1.1.2 PV Generation and Existing PMU Locations

In this section, a single line diagram of the circuit 1 has been provided which shows the location of existing field PMU devices as well as PV generation along the circuit (Figure 3-1). The DVR on the circuit is used as the representation of future customer-owned Voltage Control devices that may be needed to manage voltage and reactive power requirements for large PV installations.

As shown on the single line diagram, the areas of the circuit located between two or more feeder control devices (reclosers, regulators, shunt capacitors) are identified as monitoring areas. The total existing PV systems in each monitoring area were extracted from the GIS maps and shown on the SLD.

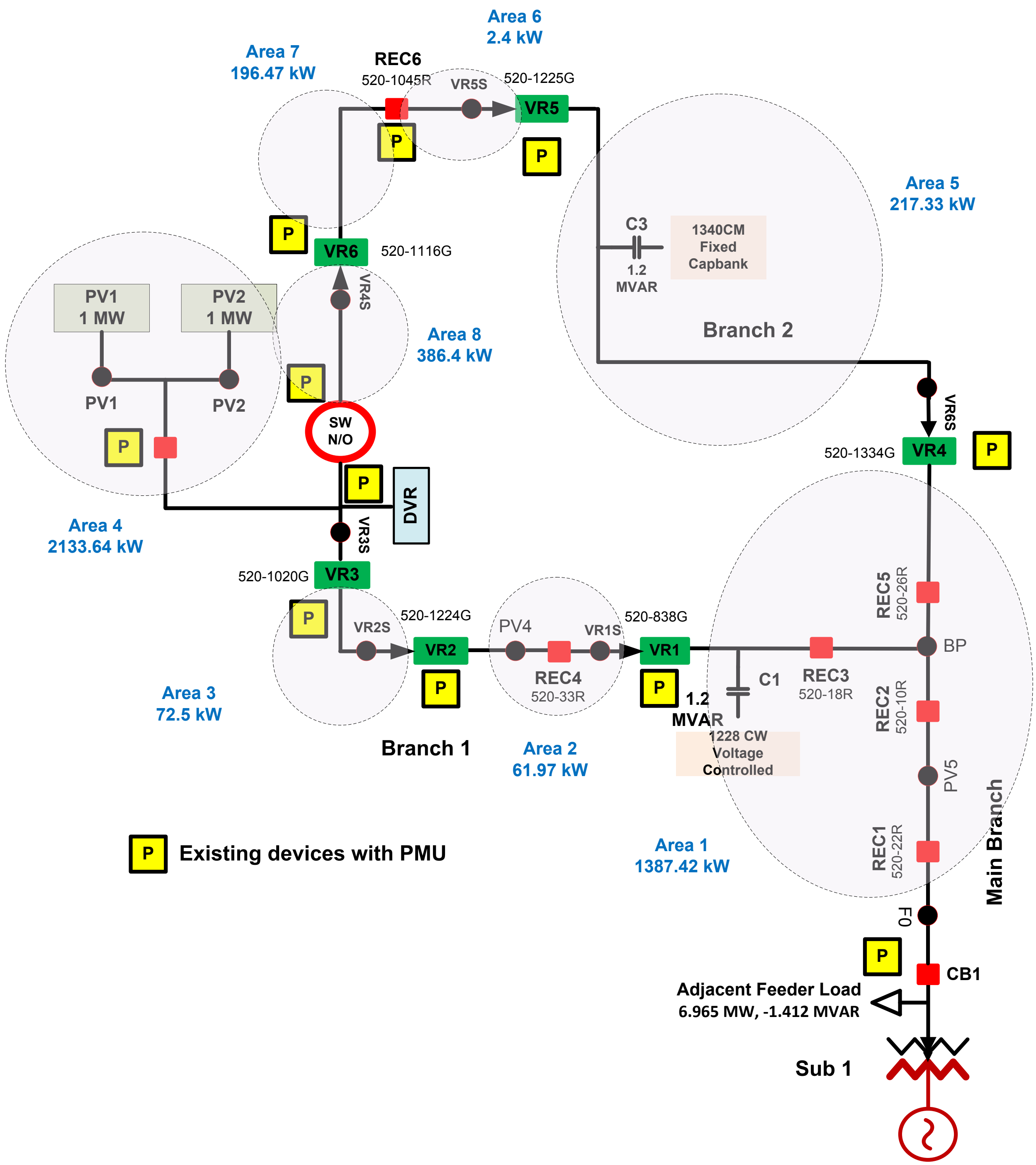

Figure 2-1. Existing PMU Locations on Circuit 1 and identifying monitoring areas with amount of PV

2.2.2 PMU Analysis and Placement Criteria

Reliable operation of modern power systems requires close monitoring of the system operating conditions. Until recently, the measurements were provided by supervisory control and data acquisition (SCADA) system, including power flows and bus voltage magnitudes. The deployment of phasor measurement units (PMUs) enables various applications with the use of synchronized measurements. A PMU installed at a node can make direct measurements of the voltage phasor of the bus and the current phasors of some or all its incoming/outgoing branches, based on the PMU available channels.

Considering PMU procurement and installation cost, the communication system availability and/or cost (which may be higher than that of the PMUs), and the practical constraints, the optimal placement of PMUs has become an essential task. While there have been multiple efforts to analyze and optimize PMU placement, the majority of these works is focused on transmission systems. Some important factors in PMU placement include network reliability, redundancy, system observability, and the required applications. In the following paragraphs some of the PMU placement considerations and recommendations are discussed.

2.2.2.1 Prioritization

To maximize the value from a PMU-based system, the communications system and software analytics need to be designed with a clear plan that suits system design, acquisition, siting and installation requirements that are tailored to the intended applications. In the initial stage of PMU system deployment, it is essential for the utility to prioritize short- and long-term objectives as well as applications of interest; this is usually done through some sort of roadmap developed for this purpose. Subsequently, those circuits where PMUs need to be deployed can be selected. The following provides a generic list of circuit priority criteria (sorted from higher priority to lower priority):

1) Availability of communications infrastructure
2) Existing location of distributed energy resources (DERs), especially intermittent ones
3) Expected penetration of DERs (especially intermittent ones)
4) Reliability level
5) Power quality level
6) Feeder type (Residential, Industrial, Commercial).

Once the circuit priorities are determined, the next step would be to find the optimal (or close to optimal) locations of PMUs that enable successful implementation of the application of interest. The favorable locations are areas with pre-installed feeder control devices which provide CT and PT connection. For uncovered areas, new nodes can be identified and incorporated in the new device installations.

2.2.2.2 Intended Applications

PMU placement should reflect the needs and functionalities of the intended applications for the distribution system. More specifically, PMUs should be located in a manner to maximize system benefits, beyond those provided by conventional meters. In the case of distribution systems, and potential future implementation at SDG&E, PMU applications were grouped in five broad categories. The following is a list of five categories along with some examples for each category:

1) System monitoring
   a) Wide-area situational awareness
   b) Phase angle monitoring for voltages and currents

2) Assessment and analysis
   a) Voltage stability monitoring and prediction
   b) Enhanced state estimation

3) Model validation
   a) Short circuit study validation
   b) Load characterization, load modeling and load forecasting

4) Protection and automation (mitigation, enhancement, and detection)
   a) Fault location
   b) Islanding detection in the presence of DERs

5) Control and optimization
   a) Volt/Var control
   b) Fault location and load restoration

Table 3-7 below offers a more detailed list of potential PMU applications in distribution systems. The list has been compiled from survey of various distribution automation applications and proposed use cases by several smart grid working groups, such as DOE smartgrid interoperability group (SGIP). As it can be observed in the table, synchrophasor measurements can be utilized for an array of applications and, thus, PMU placement should support the requirements of these applications.

Table 2-8 provides a list of recommended key PMU locations and PMU coverages for various automation and smartgrid applications. The list was prepared by applying the aforementioned criteria.

Table 2-7. List of Potential PMU Application in Distribution Systems

No	APPLICATIONS	CATEGORY				
		SYSTEM MONITORING	MODEL VALIDATION	ANALYSIS	PROTECTION & AUTOMATION	CONTROL
1	Conservation Voltage Reduction (CVR)					X
2	Faulted Circuit Indication(FCI) for expediting service restoration				X	
3	Falling conductor and high-impedance fault detection				X	
4	Distribution system computational model validation		X			
5	Voltage impact assessment and mitigation due to high penetration of intermittent DER			X		X
6	Voltage and current phase angle monitoring	X				
7	DER islanding detection				X	
8	Volt-Var Control					X
9	Power flow measurement for circuit design evaluation and balancing (passive approach)	X		X		
10	Monitoring and integration of intermittent DERs	X				
11	Incipient fault & failure detection				X	
12	Improved wide-area situational awareness	X				
13	Customer/smart inverter control					X
14	Voltage profile monitoring			X		
15	Dynamic rating of distribution lines and equipment (including thermal limit assessment)	X		X		
16	Improved load shedding schemes					X
17	Condition monitoring and asset managment of power apparatus	X				
18	Phase identification					X
19	Near real-time event monitoring and trending	X				
20	Active and reactive reverse power flow management					X
21	Planned islanding and restoration of microgrids					X
22	Short circuit study validation		X			
23	Fault protection and reclosing assistance (real-time values to relays and reclosers to adapt to system changes)				X	
24	High accuracy fault location, specific for maintenance dispatch plus OMS interface				X	
25	Control instablility, oscillation detection - Volt/Var switching					X
26	Load shedding (real-time compensative arming to balance 1547-compliant PV that will drop during wide area disturbances)				X	
27	Enhanced FLISR operation				X	
28	Closed-loop circuit operation					X
29	Power quality measurement and management information per customer group - voltage profile, CBEMA/ITIC violations	X				
30	Recording, retrieval, trigger marking, archiving, and disposal of gathered synchrophasor and other circuit data	X		X		
31	Monitoring of communications system performance with management metrics - availability, latency, lost packets, etc.	X				
32	Communications failure location for maintenance dispatch	X			X	
33	Monitoring, alarming and compensating of malfunctioning PMU installations by integrated comparison with surrounding data	X		X		
34	DER management and energy balancing					X
35	Synchronized load transfer on same circuit or between adjacent circuits (under normal operating conditions)				X	
36	Circuit loss minimization			X		X
37	Improved distribution reliability analysis (index calculation)			X		
38	Distribution system state estimation			X		
39	Open conductor fault detection				X	
40	Load characterization and forecasting			X		
41	Post-mortem analysis			X		
42	Energy accounting/non-technical losses estimation and location via cross-feed to AMI and CIS	X		X		
43	Real-time event monitoring and trending	X				
44	Frequency monitoring and analysis	X		X		
45	Voltage stability monitoring and prediction	X				X
46	Visualization of dynamic system response	X				

Table 2-8. Recommended Locations for PMUs for Various Classes of Applications

Item #	Application	Recommended PMU Placement
1	Improved situational awareness	• DERs with a combined capacity above certain kW rating (500kW) • Key buses, e.g., those with VRs, LTCs, and capacitor banks • Major load centers • Flowgates requiring loading relief • Interfaces to transmission systems • Pre-defined islands
2	Real-time monitoring and trending	Similar to recommended locations for Item #1
3	Distribution system state estimation (Phasor-based or enhanced)	• (N-2) line current phasors are needed for N interconnected buses • More PMUs neded if robustness again single PMU failure is needed • Observability criteria should be considered
4	Voltage stability monitoring and prediction	• DERs with a combined capacity above certain kW rating (500kW) • Large reactive power control installations (DSTATCOM, synchronous condensers, Large capacitor banks, etc.) • Voltage control installations (LTCs, VRs, etc.) • Theoritically, a minimum of (N-1) line current phasors are needed for N interconnected buses
5	Dynamic rating, thermal limit, and stability limit assessment (e.g., islanded microgrid)	• Voltage and current of the distribution line(s) • DERs with a combined capacity above certain kW rating (500kW) • Large load centers • Tie lines between sub-systems (e.g., in a looped configuration) • Interfaces to transmission systems
6	Synchronized load transfer, distribution sub-system separation, and phase identification	• PMUs to be installed at both sides of the interface/tie • Single-phase control devices (VRs, Cap banks, etc.)
7	Model verification/calibration	Components of interest (DERs, grid power controllers, loads, etc.)
8	(Frequency) Oscillation detection	• All DERs (espacially wind power plants) • Large loads (especially industrial loads with cyclic loadings) • Grid control devices (DSTATCOM, switched capacitors)
9	DER islanding detection	• All DERs • Points of interconnection (POIs)
10	Blackstart and system restoration	• Every generator included in the blackstart restoration plan • Every substation included in the blackstart restoration plan • Key substations, lines, and breakers that will synchronize the blackstart islands created during the blackstart restoration plan
11	Vol/Var control	• Volt/Var control devices (sub LTC, VR, Cap Banks) • DERs with a capacity above certain kW rating (particulalry dispatchable ones) • Large loads/customers and circuit reclosers (supplimentary)
12	Fault location, isolation, and system restoration (FLISR)	• Substation (monitoring circuit breaker current) • Circuit reclosers • Remote control switches • Sectionalizer and tie breakers/switches • Load centers • Large customers and beginning of large branches (supplimentary)
13	Falling conductor detection	• Substation (monitoring circuit breaker power) • Circuit reclosers • Branch end point
14	Monitoring and integration of intermittent DERs	• POI of variable DERs (and other DERs as supplimentary location) • Substation (monitoring circuit breaker power) • Circuit reclosers

Based on the intended applications, the criteria and practices for PMU placement will vary. Table 3-8 provides generally recommended locations for a selected number of PMU applications in distribution systems.

As indicated in this table, some of the PMU locations are mandatory while the rest are supplementary for enhanced operation of the application. The following is a list of recommendations for prioritizing PMU placement based on the applications of interest:

- Key applications that will bring value to the organization (e.g., engineering analysis and real-time operational applications) should be identified and prioritized as soon as possible. Applications require different levels of accuracy, resolution, as well as placement; these should be taken into account prior to concerted deployment of PMUs.
- Determine the placement coverage required for successful operation of the application(s) of interest. Determine if partial coverage can suit the needs of some applications while others may require full observability/deployment.
- An application matrix can be developed to track the locations that PMUs can meet the needs of multiple applications. These locations may be considered higher priority since they provide cross-cutting value to multiple PMU-based applications.
- Data quality is important in most cases, but some applications have less stringent requirements for data quality and accuracy than others. This should be considered in the deployment stage, and efforts should focus on ensuring a high availability, high accuracy, and low latency synchrophasor network.

It is should be noted that one of the major criteria for PMU placement is the system observability. If the full observability of the system is fulfilled by PMUs, the majority of applications can be performed properly (but it is usually not practical due to the cost constraints). The following subsection discusses the criteria for the optimal placement of PMUs when the system observability is the optimization objective.

Other additional factors that influence PMU placement include:

1. Practical constraints for PMU installation (e.g., non-existent virtual buses or unavailability of instrument transformers)
2. The number of distribution lines and transformers in the substation (possibility of installing more PMUs at a substation)
3. Equipment considerations (number of inputs, signal availability, local access, communication interface, timing signal, etc.)
4. The redundancy requirements for PMUs
5. Possibility of using existing intelligent electronic devices (IEDs) as PMU
6. Communication & IT considerations (Bandwidth, latency, reliability, security, etc.)
7. Data quality requirements (data loss, data corruption, inaccuracy, etc.)
8. Reporting rate as related to communication restrictions, application requirements, data handling equipment, and data storage capacity

Based on the discussion above and the scope of this project and its related applications, the following table (Table 3-9) provides a high-level guideline for placement of PMUs in target distribution systems. The table lists a generic prioritization for distribution assets that are proper candidates for PMU locations in selected circuits.

However, it should be emphasized that PMU placement should be investigated in the context of the system under study.

Table 2-9. Recommended Location of PMU Installations for Analyzed Circuits

Priority level	Description	Recommended Locations
1	Major locations that are critical for majority of PMU-based applications or have high potential for PMU installation	• Substation circuit breakers • Circuit reclosers • Utility side of DERs with a capacity more than 500kW • New SCADA control devices • Automated assets that are monitored by SCADA, and their control & communication can be replaced with PMUs, e.g., VRs, cap. banks, SCADA switches/ties, reclosers, etc.
2	Automated assets that are not monitored by SCADA, but their control & communication can be replaced with PMUs	• Residential DER clusters (areas with more than 100 residential DERs eache smaller than 10kW) • Voltage Regulators (VRs) • Switched capacitor banks • Sectionalizers, and DA switches/ties • reclosers, etc.
3	Critical locations for specific PMU applications	• Load centers and/or mid-circuit point • Beginning of large branches • large custumer and industrial loads
4	Automated assets that are not monitored by SCADA, and their control & communication cannot be replaced with PMUs	• Voltage Regulators (VRs) • Switched capacitor banks • Sectionalizers, and DA switches/ties • reclosers, etc.
NOTE: PMUs will be placed at the above recommended locations, provided that no other control device (VR, cap bank, recloser, or SCADA switch/tie) with synchrophasor measurement capability is located less than half a mile from it.		

2.2.3 PMU Placement Case Study

In order to investigate and further modify the applicability of the proposed PMU allocation criteria, the method was examined on a few circuits in SDG&E territory. There are some PMUs already deployed in distribution circuits. The objective of this approach was to show whether additional PMU devices were needed or the existing units can provide proper coverage for the selected use cases.

Three circuits were selected and studied for this purpose; however, in this report, the results applied to one of the circuits (Circuit 1) are presented. Similar analysis for other circuits were also performed as part of lab setup development.

Figure 3-1 presented above shows a schematic of Circuit 1. A normally open switch divides the circuit into two main branches. All key devices including voltage regulators, capacitor banks, reclosers and DERs have been drawn in this schematic. Currently there are 24 PMU devices located on Circuit 1. Two of these PMU devices are at the substation and the rest are located along the circuit at:

- Voltage Regulators (VR1, VR2, VR3, VR4, VR5 and VR6)
- Dynamic Voltage Regulator (DVR)
- Two reclosers (REC3 and REC5)
- Trayer switch.

In circuit 1, there were two capacitor banks (one switched and the other one fixed) with no PMU coverage. Only two reclosers had PMU devices in the circuit.

The intended application was distribution system monitoring in presence of DERs integrated to the system. The intended applications in the scope of this work included:

1. Monitoring and integration of intermittent DERs
2. Real time monitoring and trending
3. Improved situational awareness.

Based on the recommended PMU locations described in Table 3-7, the following locations were hence recommended:

- Point of Interconnection (POI) of variable DERs (and other DERs as supplementary location)
- Substation (monitoring circuit breaker power)
- Circuit reclosers
- DERs with a combined capacity above certain kW rating (500 kW)
- Key buses, e.g. those with VRs, LTCs and capacitor banks
- Major load centers
- Flowgates (transformers, circuit heads, laterals) requiring loading relief
- Interfaces to transmission systems
- Pre-defined islands.

Figure 3-2 shows a single line diagram of the Circuit 1 with proposed PMU locations. Similar study was done for other two circuits. Based on these recommendations, an RTDS model was developed and used for the purpose of pre-commercial demonstration of system integration and visualization in the laboratory environment.

The existing PMUs are located at the circuit substation, all the voltage regulators, DERs and two of the reclosers (REC3 and REC5). There is no PMU devices located at the remaining four reclosers and two key buses with capacitor.

Therefore, four new locations were recommended for PMU placement as shown in Figure 3-2. PMU placement at the capacitor back supports enhancing the visibility of the system and monitoring the reactive power injections due to the DERs power variations.

Note that REC1 location is electrically the same as CB1 location. Also, instead of REC2 location, it is more applicable to add PMU to REC3 and REC5 for monitoring each branches.

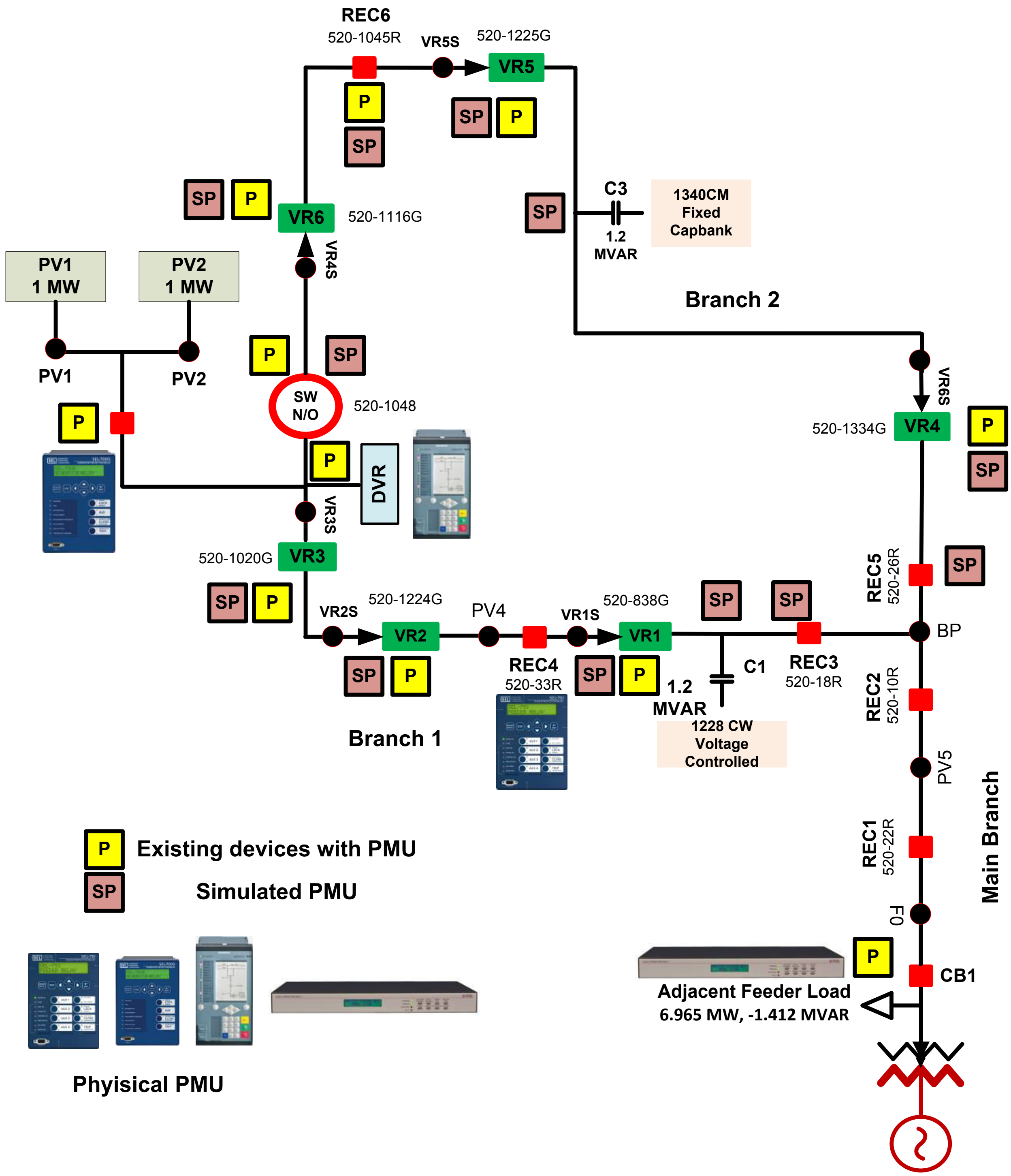

Figure 2-2. The single line diagram of a selected Circuit 1 with PMU locations (existing and recommended)

2.3 Use Case Development

For the purpose of demonstration of the technology, a set of use cases were developed. The proposed use cases were associated with monitoring, investigation and identification of Customer Systems Impact on distribution systems. Three categories of use cases were proposed in order of priority for development and implementation (tier 1, tier 2, and tier 3).

The use cases are by nature also of three types:

a. System monitoring only in real-time (without any analysis)
b. Using monitoring data for diagnostic based on simple logic or intelligent data analytics
c. Post mortem root-cause analysis of events and reported casualties in the system.

An extensive list of use cases was proposed and they were categorized in three tiers, by relevance. For the purpose of design and implementation of the system on this project, the following use cases were selected as the most important ones:

1. Voltage and power flow monitoring of customer systems
2. Primary Distribution Asset Operation Monitoring and Diagnostics
3. Data Quality Validation for Field PMUs
4. Equipment overloading detection
5. DER Interconnection Compliance
6. Water Treatment Facility Monitoring and Reactive Power Management

Use case documentation report was prepared to provide detail description of each of the use cases and they were used for the design and implementation of the system.

2.4 System Monitoring, Visualization and Analytical Application Requirements

During project execution, a functional requirement document was prepared to address a set of requirements for distribution system monitoring and visualization. This document provided functional requirements for developing monitoring and visualization of distribution systems in support of integrating customer systems.

In this document, different methods of data analytics (applications) and various forms of data presentation (displays) were suggested to allow for advanced monitoring and detection of events on the circuits. Synchophasor (PMU) data could increase quality and accuracy of system monitoring and observability for the fast system events, as a critical step in enhancing the reliability of fast evolving distribution systems.

As a benchmark for studies and evaluations, several PMU devices that are presently installed on 12 kV distribution circuits in SDG&E service territory were monitored through SynchroWAVe Central software tool. Display dashboards were created for monitoring phasor magnitude and phasor angles, and compared with simulated data.

Data Sources: The main data source for the visualization application was the PMU data, either streaming from PMUs in the field, or extracted from the historical database (i.e. PI historian). In addition, SCADA data – especially for device status and loads - and any power quality data from substation power quality meter, or any customer related data from revenue meters (such as demand and secondary voltages), as available and accessible were used.

For the demonstration purposes, PMU related data from the real-time test setup that was stored in a simulation PI Historian located at SDG&E ITF were also used.

Measurements & monitoring types and format: Following is a selected list of measurements, indicators and performance indices being calculated locally at each PMU location as phasors and/or analog values. All measurements were reported in real time for monitoring purpose, including:

- Voltage and current phasors
- Active and reactive power and power factor
- Voltage and Current phase angles
- RMS voltage and current magnitude per phase and phase to phase
- Voltage and current unbalance levels
- Frequency, Rate of Change of Frequency (ROCOF)
- Harmonic distortion levels (THD for voltage and TDD for current)
- Harmonic histograms
- Voltage symmetrical components
- Voltage sag and swell, and
- Short duration transients.

Most PMU-based IEDs can provide data at 60 samples/second or even at higher sampling rate. Specific devices may provide lower data resolution. However, in this project, we used 30 frames per second for phasor data and analog values coming from PMUs, to be consistent with standard practice for PMU devices that were already installed and configured in the field.

In order to capture fast transients and issues associated with power electronic based DERs, higher data sampling resolution will be beneficial. The project shown that most transient events could be captured and reported with 30 samples per second. Lower resolution may be acceptable for the voltage quality analysis such as momentary outage, voltage sags/swell or profiling/trending.

2.4.1 Monitoring Requirements

Monitoring of the distribution circuits under consideration in this project was considered from the following two aspects:

- Operator requirements
- Engineer needs.

Operators are interested to get a 'big picture' view of the system in real or near real-time and want to be able to make informed actionable decisions based on the information presented by a system, similar to the operation control room. An environment that suits well this kind of visualization is Geospatial Information System (GIS) platform.

On the other hand, engineers prefer to have tools that can provide more insight into the system, so they can see more details at faster sampling rates, or to look at historical data and perform all sorts of analyses.

The proposed design and visualization provided parameters and indicators addressing the needs of both group (i.e. operators and engineers).

2.4.1.1 Modes of Operation

The visualization applications described in this document needed to have three operation modes:

a. Real-time monitoring: These applications operate on streaming data inputs in real-time. They are mainly intended for real-time or ear-real time visualizations and alarm generation. Applications are mostly based on the data streaming from PMU or SCADA measurements.
b. Near-Real-time for quick access to recent events (events retrieval).
c. Off line/replay mode for post-event forensic analysis: These applications operate on archived data. They are mainly intended for an analysis of past events.

2.4.1.2 Real-Time Monitoring Mode

In the real-time monitoring mode, users will be provided with the measurements using real-time PMU, SCADA[1] and other input monitoring and measurements[2]. Examples were: Trending of voltage, current, active and reactive power profiles across the system.

Trending may be done:

- as a function of time, by stacking the PMU measurements from various devices in time frame, or
- as a function of PMU locations on a circuit, covering the circuit coverage and monitoring extent.

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[1] SCADA data sampling rates are between 1 and several seconds and, but we consider it as real-time data since they can be presented to operators as soon as they become available.

[2] NOTE: In this project, some of the measurements were simulated by RTDS system but they will be generated at the rates equal to data rates provided by actual PMU devices. The visualization platform does not differ the simulated from field data, and for this reason we will treat both simulated and field data the same way, and both categories will be referred to as 'real-time data'

2.4.1.3 Data Retrieval and Events Replay Mode

This mode of operation allowed search for data stored in the historical database (historian). Selected events could be retrieved and replayed in a similar manner as live data coming from the field. Once the data was selected for replay (based of the time stamp and duration), the data was retrieved from the data historian replayed to user. The GUI provided same look and feel as if the data was streamed from the field in real-time. The only difference was an indicator showing that the data is being replayed.

2.4.1.4 Graphical User Interface

A graphical user interface (GUI) was required for visualization of input data and for visualization of outputs created by various analytics tools and applications. The GUI consisted of a multitude of displays that served various purposes. GUI is described in more detail later in this document. Some of the more important displays of the GUI are:

- Control Panel, also known as a Dashboard
- Applications buttons used to call up additional applications, dashboard and displays
- Additional displays embedded within the Dashboard.

The control panel allowed the user to do the following:

- Allow use to see at high level what is going on in the monitored area of interest
- Select real time mode or event replay mode
- Start various internal or external applications
- Start various displays based on variety of data sources
- Start, pause, resume, rewind or stop event replay.

Visualization Displays could be called from the Dashboard or within other applications. For instance, the Dashboard can have a push button that opens another display with applications based on PMU data. Similarly, a push button may be created to start a set of applications addressing Power Quality, or system reliability, to name a few.

Various custom-designed displays allowed users to monitor the status of the distribution system of interest, to provide awareness about what is going on in real-time, and to help assess the situation and provide useful tools for making informed decisions about necessary control of the system. This functional requirements document provided a more detail description of displays relevant for the Integration of Customer Systems into Electric Utility Infrastructure project, but it can be easily customized and expanded to serve additional objectives.

2.4.1.5 Computations

Graphical user interface and visualization were needed to show the operator what's going on in the system in a graphical manner. However, raw field data obtained through PMU (high resolution data) or SCADA measurements (data reporting by exception at low resolution) was not very useful for assessing what's going on in the distribution system beyond seeing how directly measured data from the field changed in time. To have a better assessment of the status of the network under consideration, there was a need to process the measurements to provide information about the system that operator can understand and act upon. This processing was done through a well-defined analytical computations, defined as a set of applications. The computational engine for these applications performed in the background and the results were presented via a set of customized displays.

Some of the computations involved a very simple processing, such as averaging, counting, simple arithmetic operation and similar. On the other hand, there were applications that required more elaborate calculations and they were based on computational and programming tool such as MATLAB and C#, to name a few.

2.4.1.6 Data Flow

A high-level system architecture and corresponding data flow is shown in the Figure 2-3 below. In this architecture, fast sampled real-time data is streamed from PMU measurements and received by Phasor Data Concentrator (PDC) to capture and store phasor data. The PMU data is sent to SynchroWAVe Central for further processing and visualization. Another class of data, is collected via SCADA system and processed by DMS in the control center. SCADA measurements and application results are retained in PI Historian, which is the repository for other data types as well (including Power Quality data, for instance).

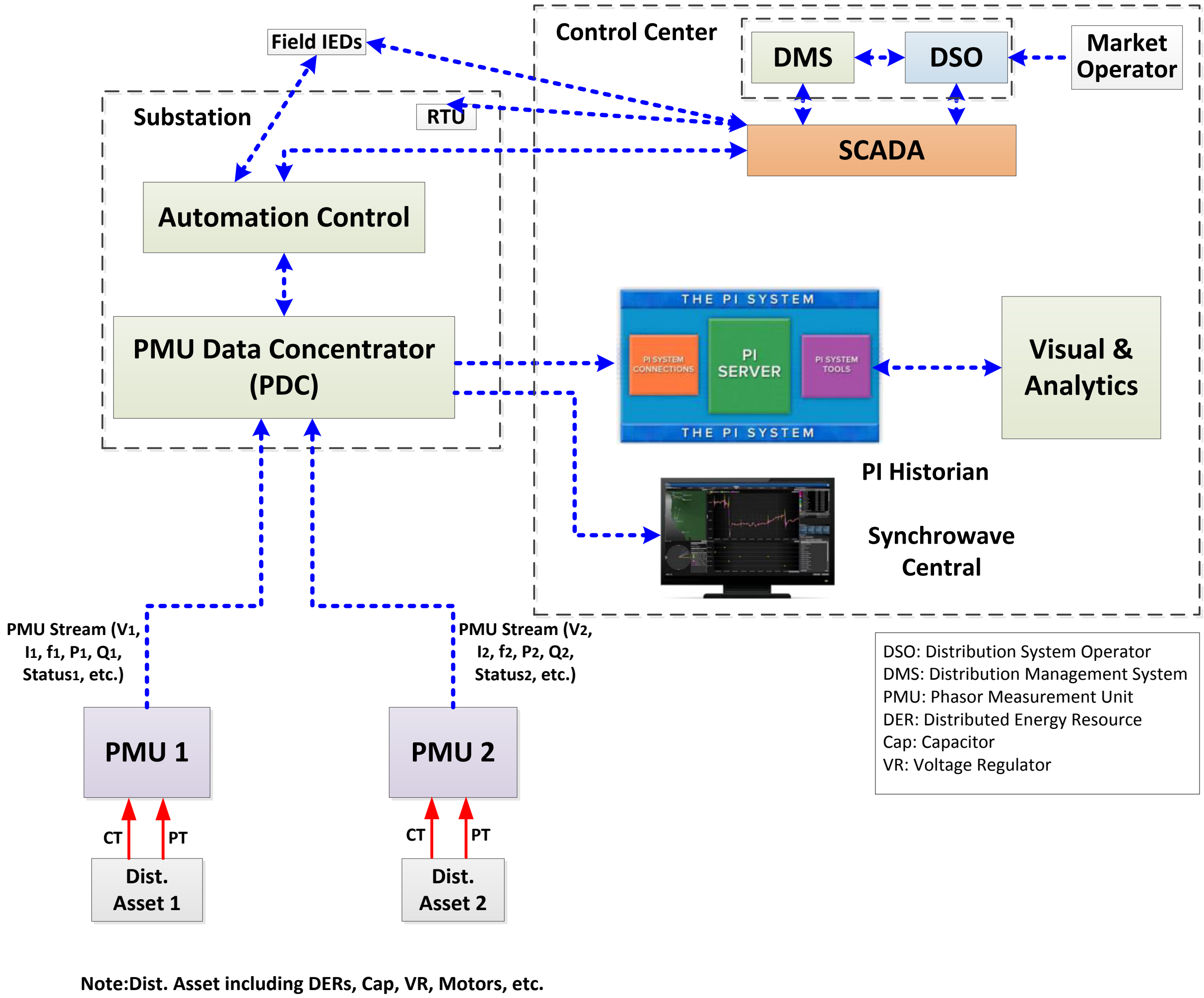


Figure 2-3. High-Level System Diagram and Data Flow for Visualization and Analytics Applications

2.4.2 Analytical Approach and Performance Indices to Streamline Operator Observations

This section describes list of methods and applications that were processing the input data and providing visualization of calculated values. For some visualization displays, a rudimentary data processing was needed, while other may require more elaborate data processing using programing tools such as MATLAB, C#, and similar programs.

The complete list of all categories of the data and information that needed to be visualized, how the information (either based on measurements or as a result of some processing) could be displayed, and possible users (Distribution Operators) or the Engineering Analysis group) are described in the following sections. These categories are listed in order of complexity to implement, as follows:

a. Measurements

b. Indicators
c. Performance Indices
d. Applications based on use case

Note that visualization aspects of these four categories above are discussed in more detail in Section 5, Operator Visualization and Display Screens.

2.4.2.1 Visualization and Measurements

This category of graphical displays takes data values coming from two sources, PMU and SCADA and presents them in appropriate format. Depending on the mode of operation (*real-time* or *post event analysis*) data source the real time PMU and SCADA measurements or their replay is used to feed the displays. The Table 2-10below shows the list of the measured parameters and possible ways to display them. The monitored data may be used by operators (for the purpose of day to day operation) or by engineers performing root-cause analysis or investigating certain events.

Table 2-10. Measurement Parameters of Monitoring Schemes

				Display Type							Users	
No	Method	Source	Description	Display in Time	Tabular	Alarm	Histogram	Phasor Diagram	Map Display	Trending	Operators	Engineers
1	Real-time Field Data	PMU	Voltage magnitude	Y	Y	Y		Y			Y	Y
2		PMU	Voltage angle	Y	Y	Y					Y	Y
3		PMU	Current magnitude	Y	Y	Y		Y			Y	Y
4		PMU	Current angle	Y	Y						Y	Y
5		PMU	Active power (total load)	Y	Y	Y	Y	Y			Y	Y
6		PMU	Reactive power	Y	Y	Y	Y				Y	Y
7		SCADA	Active power (total PV or various DERs)	Y	Y	Y	Y		Y	Y	Y	Y
8		SCADA	Customer Load				Y					
9		SCADA	Tap Position & Cap status	Y	Y				Y		Y	Y
10		PMU	Frequency	y	Y	Y					Y	Y

2.4.2.2 Indicators

Indicators are the second category of data that are of interest to present to operators or engineers. The list of indicators of interest is shown in Table 2-11. It is important to mention that for some of these indicators (such as Voltage trends, Phasor diagrams, Rate of change of frequency) can be displayed in a straightforward manner, using a standard set of displays within existing commercial platforms. Other indicators, such as those related to harmonics cannot be obtained from PMUS. Instead, other SW packages that can handle Power Quality parameters need to be used. Currently, SDG&E is using PQ View package. In this case, there needs to be a means to invoke PQView within the Visualization dashboard so Harmonic Histograms and Odd/Even Harmonics can be presented visually.

The list of indicators include parameters obtained from PMUs or PQ meters, such as:

- Voltage trends
- Phasor diagram
- Rate of change of frequency (ROCOF)
- Harmonic histograms and harmonics
- Symmetrical components
- Vector jump

- Voltage Phase Balance
- Neutral Voltage Shift

Table 2-11. Indicators for Visualizing Data

				Display Type							Users	
No	**Method**	**Source**	**Description**	**Display in Time**	**Tabular**	**Alarm**	**Histogram**	**Phasor Diagram**	**Map Display**	**Trending**	**Operators**	**Engineers**
1	Measurement data or Simple Processing	PMU	Voltage trends					Y		Y	Y	Y
2		PMU	Phasor diagram	Y	Y			Y	Y			Y
3		PMU	Rate of change of frequency (ROCOF)	Y	Y	Y	Y	Y	Y	Y	Y	Y
4		PQ meters	Harmonic histograms (obtained from PQ View)				Y					Y
5		PQ meters	Odd/even harmonics* (obtained from PW View)		Y					Y		Y
6		PMU	Symmetrical components (discuss if it is		Y			Y				Y
7		PMU	Vector jump (need to discuss further)		Y	Y	Y			Y		
8		PMU	Voltage Phase Balance									
9		PMU	Neutral voltage shift						Y			
10		Post Processor	Short duration transients (obtained from PQView)	Y	Y					Y		Y

2.4.2.3 Key Performance Indices for Visualization of Data Monitoring

Several key performance indices (KPI) are of interest for both operators and engineers. The indices clearly define the status of the system and expected impacts with pre-specified criteria to determine the level of violations. Table 2-12 below shows the list of the KPIs of interest.

2.4.2.3.1 KPI Based on Count Rate Calculations

Some of the performance indices are based on count rate calculations and they include System Average RMS Variation Frequency Index (SARFI), and tap position and capacitor counts. SARFI gives the average number of events (sags, swells, or interruptions) of a system over the assessment period, usually one year, per customer served. The size of the system is scalable: it can be defined as a single monitoring location, a single customer service, a feeder, substation, a group of substations, or an entire power delivery system. There are two types of SARFI indices: SARFI-X and SARFI-Curve.

SARFI-X corresponds to a count or rate of voltage sags, interruptions, and/or swells below or above a specified voltage threshold. For example, SARFI-90 considers voltage sags and interruptions that are below 0.90 per unit, or 90% of the reference voltage. SARFI-70 considers voltage sags and interruptions that are below 0.70 per unit, or 70% of the reference voltage. SARFI-110 considers voltage swells that are above 1.1 per unit, or 110% of the reference voltage. It is important to mention that the SARFI-X indices are meant to assess short-duration rms variation events only, meaning that the only events included in its computation are those with durations less than the minimum duration of a sustained interruption as defined by IEEE Standard 1159, which is 1 min.

SARFI-Curve corresponds to a rate of voltage sags below an equipment compatibility curve. For example, SARFI-CBEMA considers voltage sags and interruptions that are below the lower Computer Business Equipment Manufacturers Association (CBEMA) curve (CBEMA is now the ITI).8 SARFI-ITIC considers voltage sags and interruptions that are below the lower ITIC curve. SARFI-SEMI considers voltage sags and interruptions that are below the lower SEMI curve. Again, these curves limit the duration of an rms variation event to the minimum duration of a sustained interruption as defined by IEEE Std 1159, which is 1 min.

K-factor for an electrical network primarily relates to non-linear loads and is defined as a number representing the effect of harmonics on heating of transformer. For calculating the K-factor all the harmonics up to a predefined limit are considered. For industrial loads of induction motors, up to 25th harmonic currents are considered but the limit can be up to 50th.The formula for calculating the K factor of a network is[1]

$$K_{factor} = \sum (I_h) h^2$$

As from the formula, while calculating the K-factor, the harmonic current is being multiplied by the square of its number. Therefore, for higher order harmonics, being multiplied by the square of their number even small harmonic current will give considerable effects on the K-factor. For a linear network, the K factor will always be 1. As the harmonic content increases in the current, the K factor moves upwards from 1. Electronic ballasts, induction motors, UPS and all diode based switching circuits come under non-linear loads causing harmonics.

K-factor of the electrical distribution network is the reason why transformers need to be de-rated. While supplying the non-linear loads, harmonic currents flow in the transformer and to protect the windings and transformer oil from overheating, load on it needs to be reduced.

2.4.2.3.2 KPI based on near real-time calculations

Some of KPIs are based on Power Quality (PQ) measurements, and therefore cannot be obtained from PMU or SCADA data. Instead, they are measured by power quality (PQ) meters:

a. Total Demand Distortion (TDD)
b. Total Harmonic Distortion (THD)
c. Voltage unbalance factor
d. Short and long-term flicker factor

More info about these parameters and how they are calculated can be found in IEEE standards 519-2014, 1159-2009, and 1453-2005.

2.4.2.3.3 KPI based on long-term calculations

This category of indices includes:

- Solar radiation related parameters, such as
    - Daily Clearness Index (DCI) [7,8] and
    - Daily Variability Index (DVI) [7,14]
- Thermal limit (short and long-term), and
- Reliability indices, such as
    - System Average Interruption Duration Index (SAIDI),

[1] See https://zenatix.com/k-factor-for-transformer/

- System Average Interruption Frequency Index (SAIFI),
- Customer Average Interruption Duration Index (CAIDI), and
- Customer Average Interruption Frequency Index (CAIFI).

Table 2-12. Key Performance Indices for Visualization of Field Monitoring

				Display Type							Users	
No	**Method**	**Source**	**Description**	**Display in Time**	**Tabular**	**Alarm**	**Histogram**	**Phasor Diagram**	**Map Display**	**Trending**	**Operators**	**Engineers**
1	Count Rates Calc.	PI Historian	Voltage Swell (SARFI-110) - post-processing based		Y		Y		Y	Y	Y	
2		PI Historian	Voltage Sag (SARFI-80, SARFI-90), post-		Y		Y		Y	Y	Y	
3		Post Processor	Cummulative Tap and Cap Status counts		Y							
4		PI Historian	SARFI-SEMI		Y		Y		Y	Y	Y	
5		PI Historian	SARFI-ITIC (CBEMA)		Y		Y		Y	Y	Y	
6		PI Historian	K-factor (transformer derating) (Substation transformers, as it has sensors)		Y	Y	Y		Y	Y	Y	
7	(Near) Real Time Calculations	PMU/PQ meter	TDD (Available from PQ View)		Y		Y		Y	Y		Y
8		PMU/PQ meter	THD (Available from PQ View)		Y		Y		Y	Y		Y
9		Post Processor	Crest factor (distortion factor)		Y		Y		Y	Y		Y
10		PI Historian	Voltage unbalance factor (doing it in SCADA, pull this information)		Y		Y		Y	Y		Y
11		PI Historian	Flicker factor (short term)	Y	Y		Y			Y		Y
12		PI Historian	Flicker factor (long term)		Y		Y			Y		Y
13	Long-term Calculations	Post Processor	DCI (Daily Clearness Index)		Y		Y			Y	Y	
14		Post Processor	DVI (Daily Variability Index)		Y		Y			Y	Y	
15		Post Processor	Thermal limit (Lookup table for short and long-term limits)		Y	Y	Y			Y	Y	
16		Post Processor	SAIDI (available, for the whole network) (minute basis)		Y		Y			Y		
17		Post Processor	SAIFI (available, for the whole network)		Y		Y			Y	Y	
18		Post Processor	CAIDI (available, for the whole network)		Y		Y			Y	Y	
19		Post Processor	CAIFI (available, for the whole network)		Y		Y			Y	Y	

2.4.2.4 Applications of Field Monitoring

The applications are based on the functions described in use case documents that were selected, as shown in Table 2-13 below.

Table 2-13. List of applications based on use cases

				Display Type							Users	
No	**Method**	**Source**	**Description**	**Display in Time**	**Tabular**	**Alarm**	**Histogram**	**Phasor Diagram**	**Map Display**	**Trending**	**Operators**	**Engineers**
1	More elaborate Calculations (From Use Cases)	PI Historian	Voltage Power Flow Monitoring (VPFM)	Y	Y	Y	Y	Y	Y	Y	Y	Y
2		PI Historian	Primary Distribution Asset Operation Monitoring and Diagnostics (PDAMD)	Y	Y	Y	Y	Y	Y	Y	Y	Y
3		PI Historian	Data Quality Validation for Field PMUs (DQV-FP)	Y	Y	Y	Y	Y	Y	Y	Y	Y
4		PI Historian	Equipment Overload Detection (EOLD)									
5		PI Historian	DER Interconnection Compliance (DER-IC)	Y	Y	Y	Y	Y	Y	Y	Y	Y
6		PI Historian	Water Treatment Facility Monitoring and Reactive Power Management (LICFM)	Y	Y	Y	Y	Y	Y	Y	Y	Y

Explanation below provides more details about each of the applications from this table. Implementation details for each of these applications are provided in the Use Case documents (see attachments), prepared during this project for the purpose of the system design.

2.4.2.4.1 Voltage Power Flow Monitoring (VPFM)

The application based on this use case is relatively simple. The phasor data is used to calculate various power quality aspects of a circuit, in addition to voltage and current profiles, including:

- Voltage profiles based on measurements as selected nodes
- Active and reactive power flow across circuit
- Rate of change of power (ramp rate)
- Rate of change of frequency
- Power factor
- Phase angle jump (or vector jump)
- Sequence components (V1, V2, V0, I1, I2, I0)

Also, logic and mathematical functions based on the information reported from the device can be used to calculate and publish various indices in real-time measurement.

Examples are:

- Voltage sensitivity to change in active and reactive power (dV/dQ and dV/dP)
- Voltage unbalance factor (V2/V1).

Some statistical information is also important and can be extracted from the records of historical data, such as:

- Number and level of voltage sags and swells (per day, per week or user selected timeframe such as the last 2 days or so)
- Number and duration of any momentary or extended interruptions (per day, per week or user selected timeframe such as the last 2 days or so).

In addition, PMU data is used to provide:

- Demand and generation information in various parts of the circuits based on pre-defined zones
- Trends and heat maps of total generation versus loads,
- Comparison of equipment loading and ampacity (load carrying capacity), as well as flagging any possible overloading issue.

2.4.2.4.2 Primary Asset Operation Monitoring and Diagnostics

The objective of this application is:

- To monitor the distribution assets operation and gather supportive data and information that can help quantify the possible wear and tear of assets
- To identify potential issues with assets and provide diagnostic solutions
- To use asset monitoring data along with appropriate data analytics to serve the purpose of implementing condition-based monitoring, diagnostics and scheduled maintenance of asset.

This application focuses on PMU use for monitoring of distribution asset operation including status of switched capacitor banks, number of tap operation for voltage regulators and LTC, operation of reclosers and automated switches, and loading of distribution transformers. The installed PMUs at these assets can stream digital information regarding the asset status (open/close, tap position), in addition to the voltage, current and power flow values that are used to determine asset loading and utilization factors. Based on the asset status information reported by PMU devices, statistical data on the asset operation intervals and asset condition are traced and reported, such as the number of daily and cumulative tap operation for voltage regulators and load tap changer, number of switched capacitor operation and daily counts, and cumulative load curves.

It should be noted that generally distribution assets are the number one candidates for placing PMU-based intelligent electronic devices (IEDs) such as relays or digital controllers. Hence, obtaining information about the device operation should be easily achievable. The raw data about device status or number of operation will naturally come as part of data reporting from PMU devices associated with selected switchable assets. Hence, the main requirement would be to use the raw data and track the life cycle related information of the devices.

2.4.2.4.3 Data Quality Validation of Field PMU

The objective of this use case is to determine methods for validating field data quality. These include adding measurement reference points and defining expected patterns of variations and ranges of measurements for cross-checking. Reference points can be generated from neighboring locations in the field, or through simulation. Acceptable deviations from reference points should be added for flagging and alarming probable data quality deterioration. In some cases, probable root-cause of the data quality issue may be easily identified, for instance - being a sensor problem, a device problem or a communication link issue. In other cases, a deeper analysis may be needed. This may allow SDG&E to improve the logic for data quality flagging and alarming.

2.4.2.4.4 Equipment Overload Detection

The objective of this application is to:

- Detect equipment overloading
- Identify areas under stress
- Identify circuit congestions (with limitation in power flow).

Sizing for overload is important to avoid serious damage for distribution equipment such as transformers, overhead lines and cables, motors/generators and etc. A real-time measurement of distribution assets support monitoring loading of the equipment all the time and providing different level of alarming to recognize and size the loading of equipment in system normal or under stress operations. Most of the assets are equipped with overload protection devices to disconnect device and avoid serious damage under the overload situation. Having real-time monitoring of loading, system operators can follow loadings of equipment and the trend of its behavior under different normal operation scenarios as well as network events.

2.4.2.4.5 DER Interconnection Compliance

The main objectives of this applications are:

- To use the real-time PMU measurements to assess real-world operational conditions of circuit and response of interconnected DERs
- To use monitored data to evaluate and validate DER behavior under the different circumstances such as:

- DER response to changes in voltage levels, including verification of ride-through curves, and Volt/VAr schemes applied by DERs
- DER inverter behavior under the faults and their fault contribution
- DER connection, disconnection and re-connection timing, any existing ramp up, and time segregation requirements for plants with multiple units.

- To provide recommendations and solutions to planning engineers and system operators to better manage DER interconnections.

2.4.2.4.6 Large Industrial Customer Facility Monitoring

This function is divided in two applications:

1. Reactive power management
2. Flexible local generation usage.

2.4.2.4.7 Reactive Power Management

The main objective of this application is to coordinate and mange operation of large/critical industrial facilities such as Water Treatment Plants with the grid. The key operation aspects from the grid point of view are Real and Reactive power consumption, as well as potential adverse power quality issues (harmonics).

Specifically, for the reactive power management, the main value-added feature and advantage offered by the use case will be coordination of reactive power requirements from the plant with operation of shunt capacitors on the associated circuit feeding the plant.

Proper reactive power management supports loss reduction on circuits. Through reactive power control, voltage profile of the circuit can also be controlled and maintained within standard range. In selected circuit, specifically, there are three Line Monitoring locations which monitor two large pumping stations and one end-of-line circuit branch. The end-of-line location does not monitor any water facilities and therefore will be used only to monitor the overall power quality of the circuit. The other two locations monitor Water Treatment Plant's east and west pumping station. There are also two switched capacitors installed at two pumping stations which could be used as a reactive power support when the reactive power demand exceeds a certain threshold.

2.4.2.4.8 Flexible Local Generation Usage

The main purpose of this application is to shift most of the water treatment plant (WTP) demand to the daytime hours with high PV production. If a circuit has large amount of PV, one of the major operational issue is to manage power flow and corresponding voltage profile. The issue is more severe under light load condition of the circuit, causing reverse power flow.

If the circuit load can be controlled by the operator to coordinate operation with customer demands to provide a flexible usage schedule, additional load can be brought online, as needed, during high production time. Hence, coordinating load and generation can be applied by the operator to manage voltage profile and extensive operation of voltage control devices on a circuit.

To reduce energy cost in a WTP, the operating schedule for major load (large motor pumps) is closely planned during the off-peak time of the system (10 pm to 5 am). However, if proper energy cost policies can be agreed for daytime usage, to provide low cost and/or incentive driven energy consumption, the method can be used to control voltage and frequency. This approach is essentially beneficial during emergency water shortage time, when the facility has to operate pumps during daytime to fill up water tower, due to unplanned excessive water usage.

To implement flexible usage application, a new energy cost structure should be prepared to encourage daytime usage. In addition, integrating large load facilities into overall system planning and operation can make them part of critical system asset to balance load and generation. Using the dispatchability aspect of the WTP, and solar prediction, the load can be controlled to match with high PV production and avoid reverse power flow.

Furthermore, performing operation during times when renewable energy is abundant can minimize the carbon footprint needed to treat and deliver potable water to the county and thus impacting the overall Water Energy Nexus.

2.5 Development of Monitoring, Control and Operation Practices in Support of Customer Installations

The task objective was to propose and design advanced monitoring and control practices that can close the gaps in the exiting schemes to properly investigate any adverse impact and facilitate customer system integration. All of the following aspects have been incorporated: system capabilities, monitoring devices and data capturing and post-mortem analysis. The main activities in undertaking this task were:

- To determine the response requirements and operational practices to support customer systems
- To define the monitoring requirements and system architecture, including the communications and controls for advancement of system operation
- To investigate capabilities of commercially available sensors, power quality and/ revenue metering devices, and phasor measurement units (stand-alone or as part of other IEDs) that can provide high resolution data measurement and power quality data capturing and transient event recordings, such as:
  - Voltage and current phasors
  - Power flow (active and reactive)
  - Frequency tracking and reporting rate of change of frequency (ROCOF)
  - Harmonics and THD/TDD measurements
  - Fast transients
  - System status information, including switch position, voltage regulators, tap positions; and
  - circuit connectivity information

- To evaluate product capability documents from vendors; or perform laboratory tests on selected measurement devices (sensors, IEDs, PMUs) to determine accuracy, measurement resolution and quality and type of measurement data such as transient events, to understand and document expected device performance
- To define PMU requirements specific to distribution systems
- To prepare settings and configuration files for the devices in the field to support project data gathering and device control needs
- For cases of inadequate device capability and/or coverage, propose temporary methods and devices to be incorporated in the real-time simulation environment to supplement the existing devices and data coming from the field for the purpose of evaluating the tools under development.

2.5.1 Survey of Commercially Available PMU Devices

As part of identification of the devices suitable for the system integration and pre-commercial demonstration, a survey of available automation/protection/monitoring devices with PMU capability was conducted. The survey focused on devices commercially available in the market for deployment in electric distribution systems. For the purposed of comparison, the result of this survey was used to select vendor devices for the demo setup in the lab.

A number of the listed devices in the survey table have been already deployed in SDG&E distribution circuits, and their phasor data have been monitored in near real time.

Based on the survey and desired features, 4 devices have been selected for a detailed performance evaluation based on a hardware-in-the-loop RTDS testing (Type test). They were compared with a reference PMU device that has PMU certification based on NIST certification standard. Furthermore, the same devices have been utilized in the pre-commercial demonstration.

The selected devices were:

1. PMU Device 1: a protective relay usually installed at DER location; e.g., PV site, diesel generator POI to the feeder,
2. PMU Device 2: a commonly used feeder protection relay in SDG&E distribution circuits,
3. PMU Device 3: an offering from a new vendor in PMU market.
4. PMU Device 4: a new generation of fault recorder that has been considered by SDG&E as a potential option for future installation).

In the rest of this section, methodology and results of the type tests have been reported.

2.5.2 Type Test: Performance Comparison of the Selected PMU Devices

The objective of these tests was to evaluate the performance and capabilities of the aforementioned PMUs from the following aspects:

- Evaluating compliance of vendor products that are not commonly used at SDG&E distribution system
- Evaluating of the devices under test (DUTs) for providing high resolution data measurement (60 and 30 frames per second) and power quality data capturing and transient event recordings
- Determining accuracy, measurement resolution, quality and type of measurement data such as transient events for specific distribution system applications
- Evaluating interoperability of the PMU devices and measurement/communication features to make sure devices can be integrated with products from other vendors in a multi-vendor environment
- Capability to transfer analog and digital signals in C37.118 format – for values internally calculated at device level (for example, THD or flicker, etc.)

The test results were used to select appropriate devices and to develop measurement features for the integration testing and monitoring of distribution applications in support of customer technology integrations.

Note that only the results of selected tests from each test group are presented in this document. The reason is that many of the tests are very similar in each test group and repeating similar results does not provide any additional information. However, all the results of different tests were submitted in a complete test report to SDG&E.

2.5.2.1 Type Test Approach Description

A real-time digital simulator (RTDS) has been used to represent a 12 kV simplified distribution circuit where the devices under test (DUT) are connected at certain locations for voltage and current measurements. A simplified single line diagram of the RTDS real time view of the model is shown in Figure 2-4. The location of the PMU device under the test is shown with a red rectangular (PQ meter) where the voltage and current signals are taken.

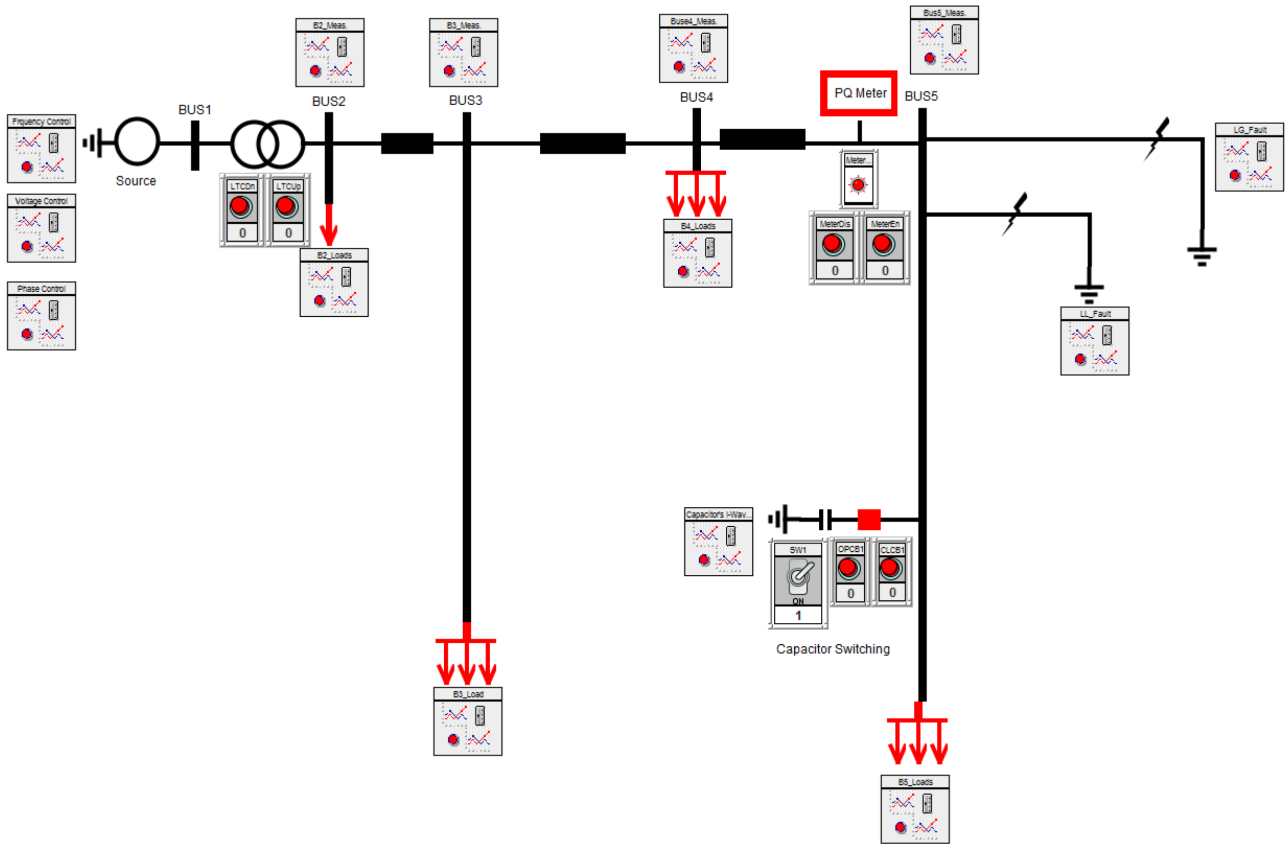


Figure 2-4. Real-time RTDS View of the Distribution Circuit Used for Device Tests

A Phasor Data Concentrator (PDC) was used to communicate with DUTs, capturing PMU data streams for data analysis and performance evaluation. Different test categories under either steady state system conditions or dynamic system conditions were performed to evaluate the performance of each DUT. For the test categories to be performed, all DUTs were configured with the maximum available phasor and analog measurements based on the DUT capability.

Depending on the test, the performance of PMUs was evaluated through Total Vector Error (TVE), Frequency Error (FE), Rate of change of Frequency Error (RFE), or the transient response comparison of the PMUs.

2.5.2.2 Testbed setup

The hardware testbed for PMU performance testing was setup and operated at the RTDS lab in SDG&E ITF. A PDC unit was setup for data stream capturing and interoperability tests. The general layout of the testbed is illustrated in Figure 3-5, consisting of the following components:

- **RTDS:** used to simulate the virtual PMU and a 12kV simplified distribution circuit including: a source, line impedances and loads.
- **PMU Device 1:** DUT1 for phasor data measurement and streaming

- **PMU Device 1:** DUT2 for phasor data measurement and streaming
- **PMU Device 3:** DUT3 for phasor data measurement and streaming
- **Reference PMU:** DUT4 for phasor data measurement and streaming. It is used as the reference PMU.
- **GPS clock** used for time synchronization of RTDS, DUTs.
- **PDC** for communicating with DUTs, capturing PMU data streams and evaluating DUTs' performance
- **Power amplifier**

Figures 3-5 and 3-6 show the block diagram of the type test setup as well as actual setup at the SDG&E ITF Lab.

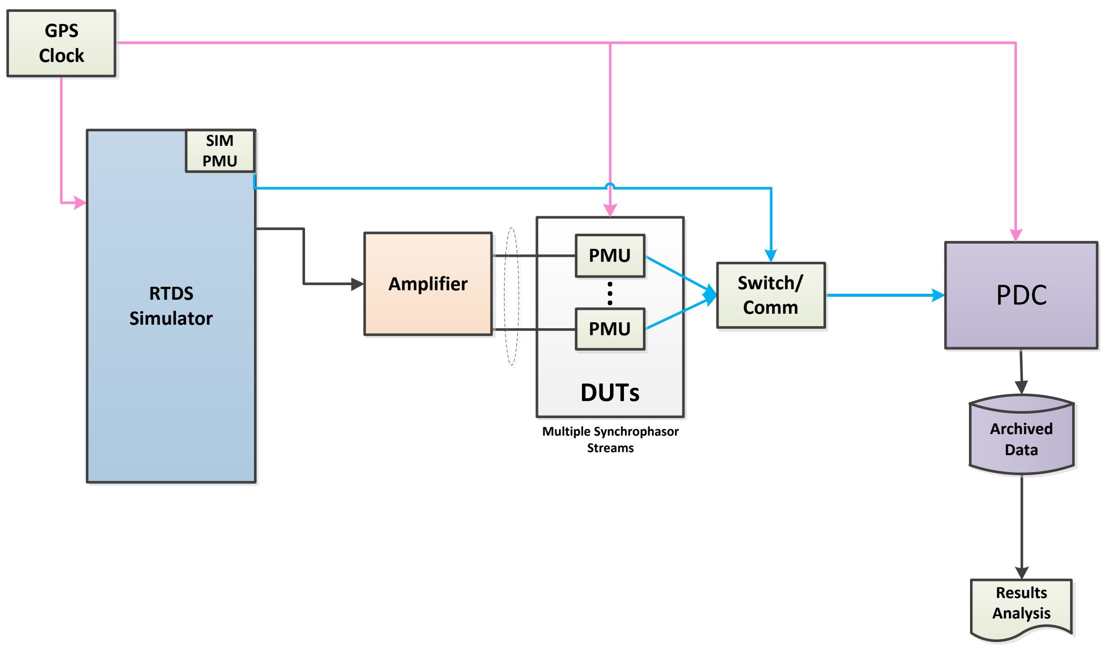


Figure 2-5. PMU Testbed Setup layout

Figure 2-6. PMU Test Setup at the ITF lab

2.5.2.3 Summary of Test Cases and Categories

Test cases have been categorized in 3 main groups:

a. Category 1: Steady state performance test. In this test category, the performance of the PMUs subsequent to different steady state conditions such as frequency variations and harmonics was studied.

b. Category 2: Dynamic performance test. Different transient scenarios such as cap switching, frequency ramp, and voltage and phase angle step change were applied to the PMUs, and their responses were compared.

c. Category 3: Verification of analog and digital data streaming. In this test category, aim was to verify a DUT capability for streaming locally measured power quality parameters or any parameter that was calculated at device level using mathematical and logical blocks.

2.5.2.4 Evaluation Method

PMU type tests focused on testing the M performance class of DUTs according to the definition in IEEE C37.118 - 2011. Before the representation of the results, it is necessary to provide some definitions:

Total Vector Error (TVE): TVE is defined as:

$$TVE = \frac{|V_{measured} - V_{true}|}{|V_{true}|}$$

In which (V_{true}) is the reference phasor and $V_{measured}$ is the phasor obtained from the PMU. In this report, the reference phasor(V_{true}) is considered as the output of the Reference PMU, because it is a certified PMU.

Frequency Error (FE): FE is defined as

$$FE = |f_{true} - f_{measured}|$$

Rate of Change of Frequency Error (ROCOF or RFE): RFE is defined as

$$RFE = |\left(\frac{df}{dt}\right)_{true} - \left(\frac{df}{dt}\right)_{measured}$$

2.5.2.5 Category 1: Steady-State Performance Test

The purpose of this test category was to test the DUTs' performance under steady state conditions. The phasor measurements estimate under steady-state conditions were compared with the Reference PMU measurement and FE and ROCOF are compared to the nominal values.

TVE, FE, and RFE was calculated and compared with defined limits in IEEE C37.118.1. Several test groups was considered in this test category. All the test groups in category 1 were performed with DUTs' reporting rate set at 60 frames/second.

2.5.2.5.1 Group 1: Voltage Magnitude Test

Group 1 tests were designed for evaluating the DUTs' performance for steady state voltage magnitude measurements. For group 1 tests, balanced three phase system voltages and currents at nominal system frequency were applied to the DUTs. Each of the following test cases was repeated 3 times for test results validation.

- **Case 1-1-1:** System voltage was set at nominal system voltage and the PMU data streams were captured for 5 seconds. The following figures show the TVE for voltage phasors, FE and RFE.

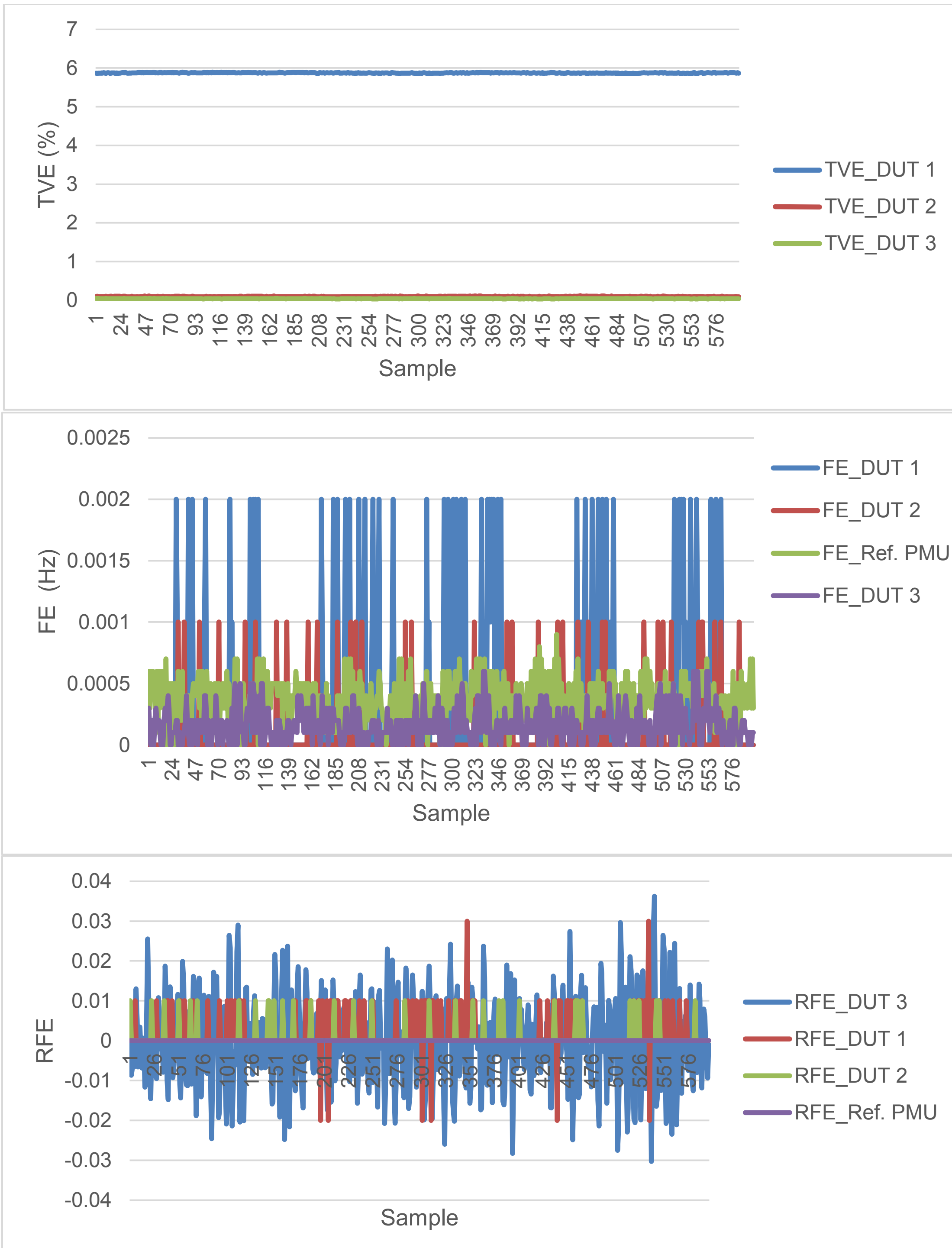


Figure 2-7. TVE, FE, and RFE Comparison for Nominal Voltage (Case 1-1-1)

- **Case 1-1-2:** System voltage was set at 50% of nominal system voltage and the PMU data streams were captured for 5 seconds. The following figures show the TVE for voltage phasors, FE and RFE. Except DUT1, all other devices showed acceptable results and errors within the expected range. The measurement offset of DUT1 created a large TVE % error comparing to others.

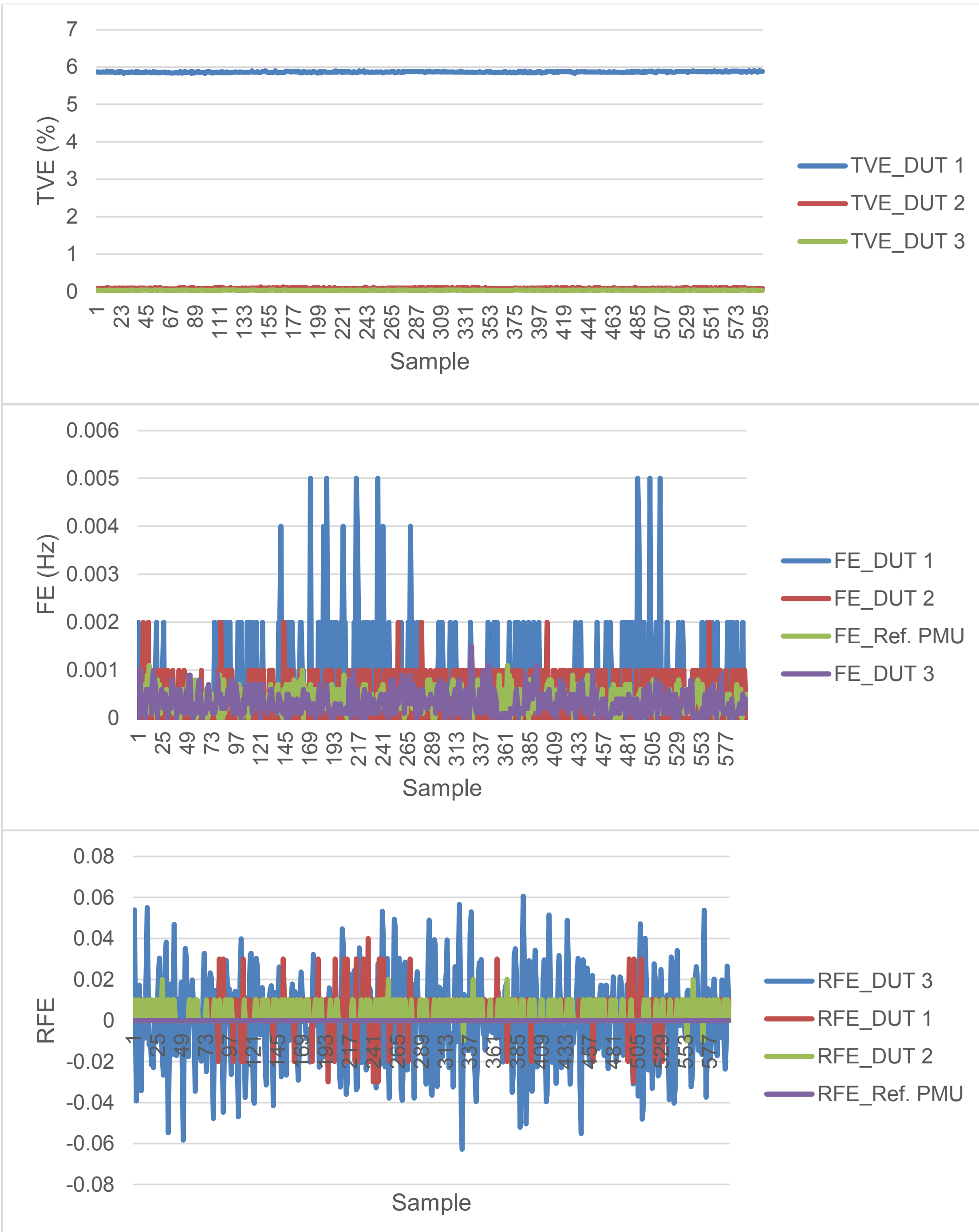


Figure 2-8. TVE, FE, and RFE Comparison for 50% of the Nominal Voltage (Case 1-1-2)

- **Case 1-1-3:** System voltage was set at 130% of nominal system voltage and the PMU data streams were captured for 5 seconds. The following figures show the TVE for voltage phasors, FE and RFE. As can be seen, DUT 1 had a 6% error due to inaccuracy in phasor measurements.

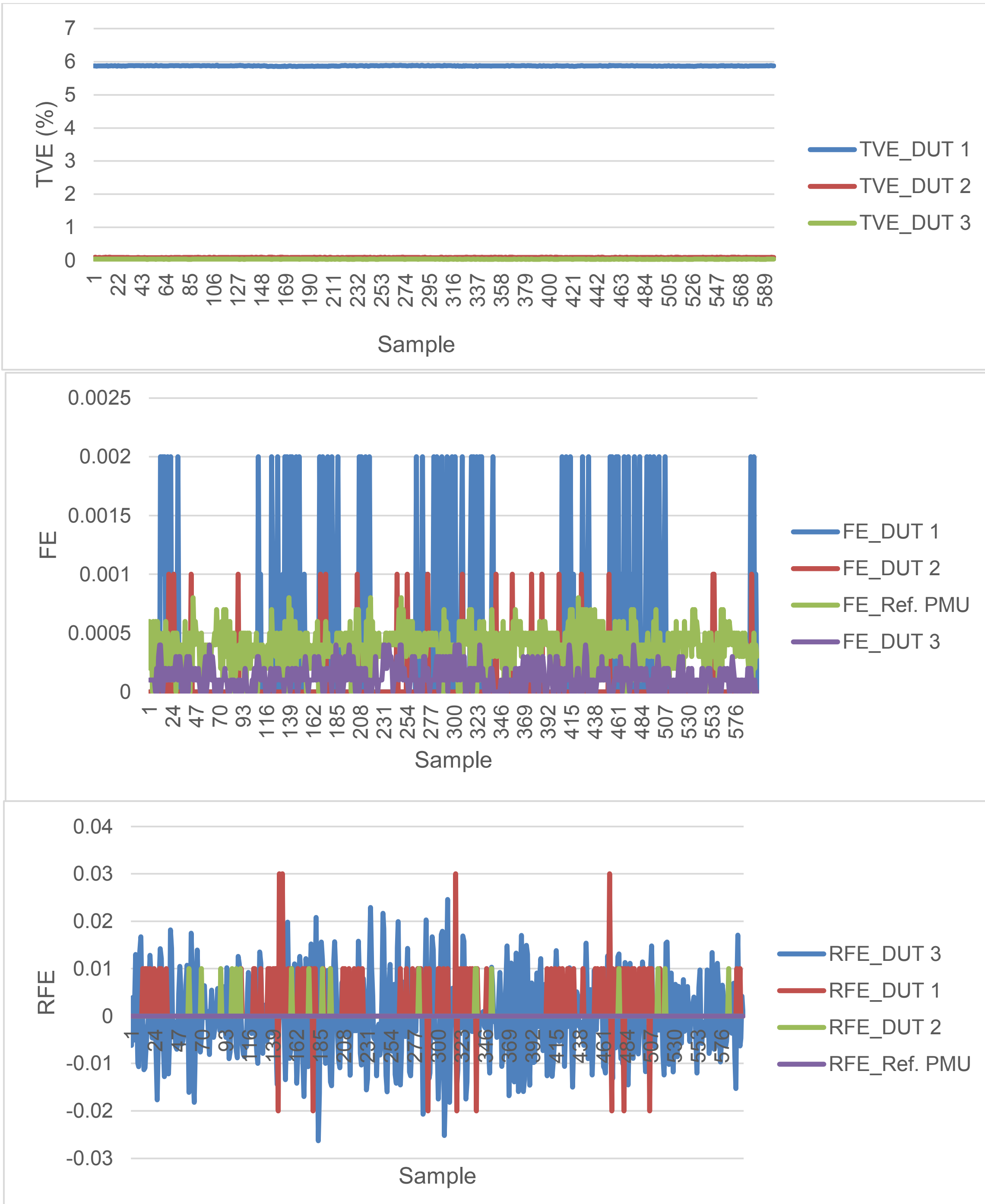


Figure 2-9. TVE, FE, RFE for 130% of Nominal Voltage (Case 1-1-3)

- **Case 1-1-4:** System voltage was set at nominal system voltage and run for 20 seconds. Phase B was disconnected at the source, and positive and negative sequence measurements from PMUs were recorded before and after the disconnection. It should be noted that DUT1 and DUT2 do not provide negative sequence measurements; therefore, the values had to be calculated using ABC phasors. The following figure shows the magnitude and TVE for positive sequence.

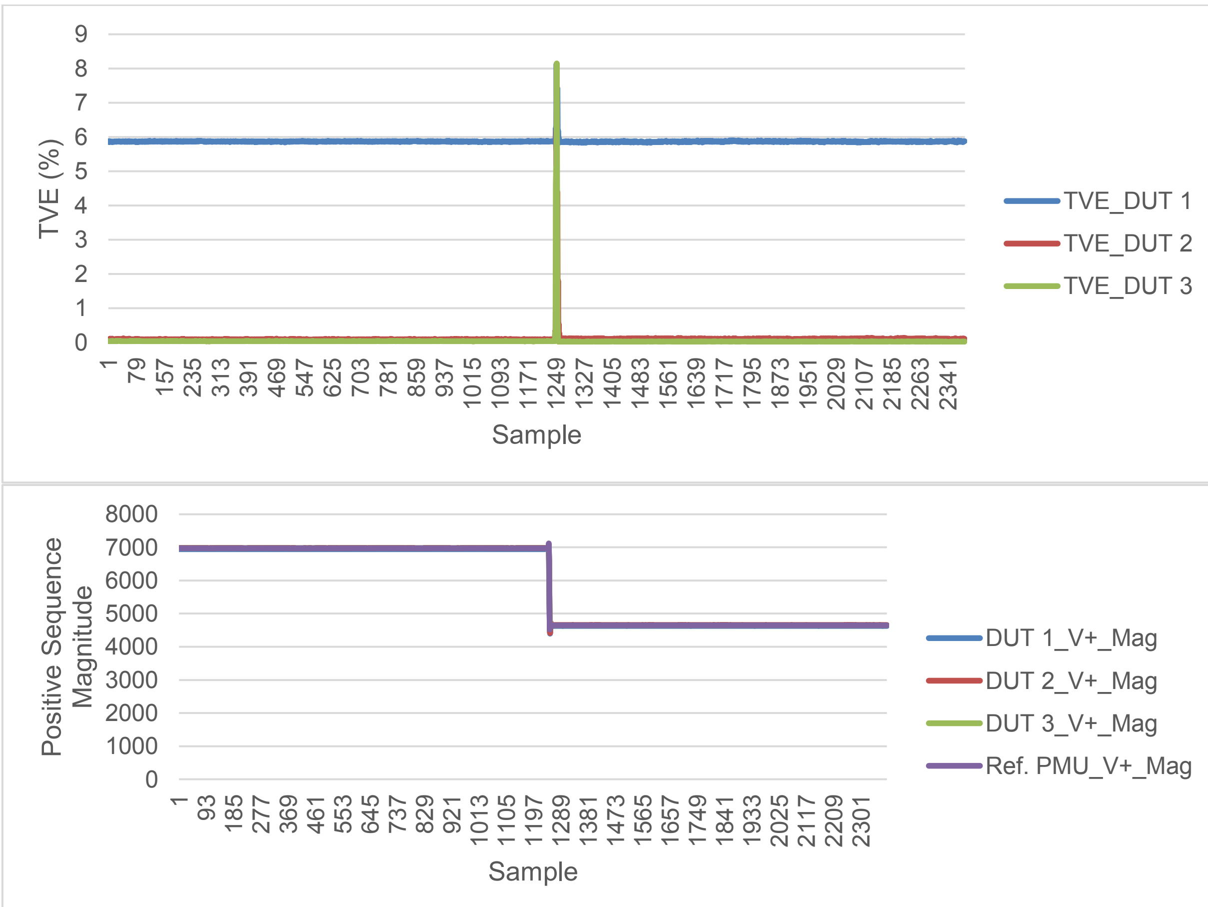


Figure 2-10. TVE and Magnitude of the Positive Sequence Subsequent to the Disconnection of Phase B (Case 1-1-4)

It can be seen that during the step change, a spike happened in the TVE. The duration of this spike was around 8 samples for all PMUs, which showed the convergence rate of the PMUs.

The next figure shows the TVE and magnitude of negative sequence. It should be noted that TVE was just shown during unbalanced operation of the system.

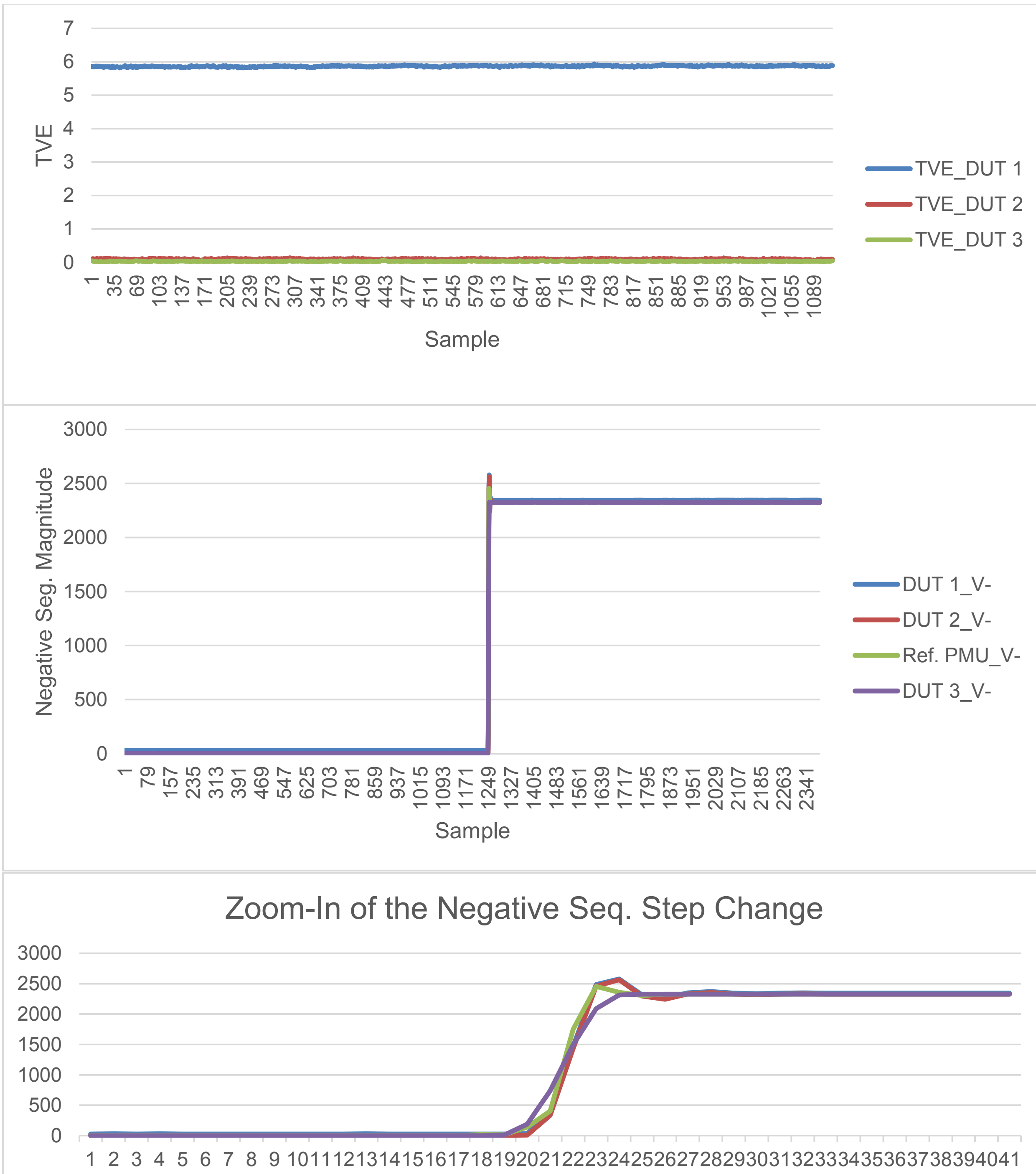


Figure 2-11. TVE and Magnitude of the Negative Sequence Subsequent to the Disconnection of Phase B (Case 1-1-4)

Note: Case 1-1-5 and case 1-1-6 are excluded because of their similarity to the previous results.

- **Case 1-1-7:** System was set at the nominal frequency, two phase voltages at nominal voltage and the third at 105% of nominal voltage. PMU data were captured for 5 seconds. The magnitude and TVE of the positive sequence as well as the magnitude and TVE of the negative sequence are shown in the following figures.

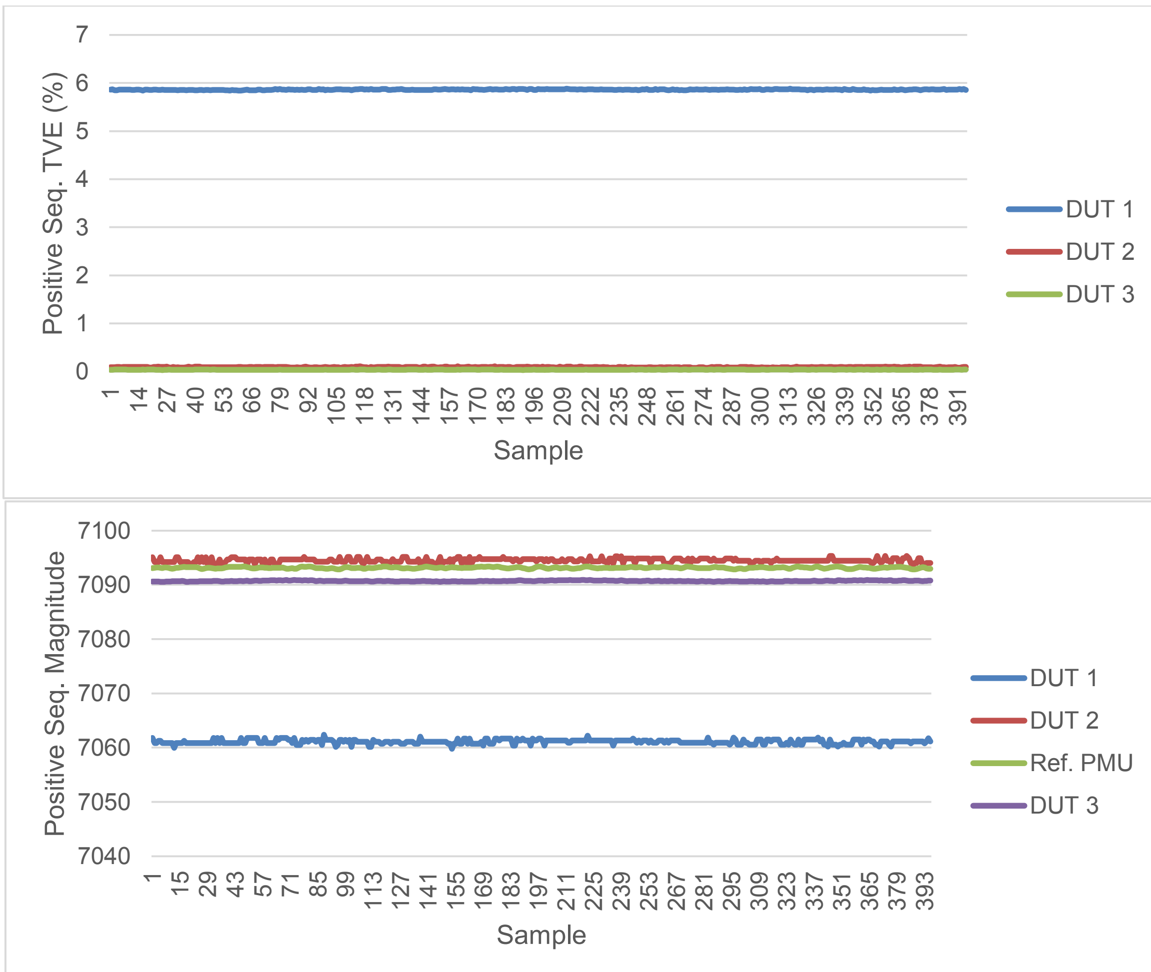


Figure 2-12. TVE and Magnitude of the Negative Sequence (Case 1-1-7)

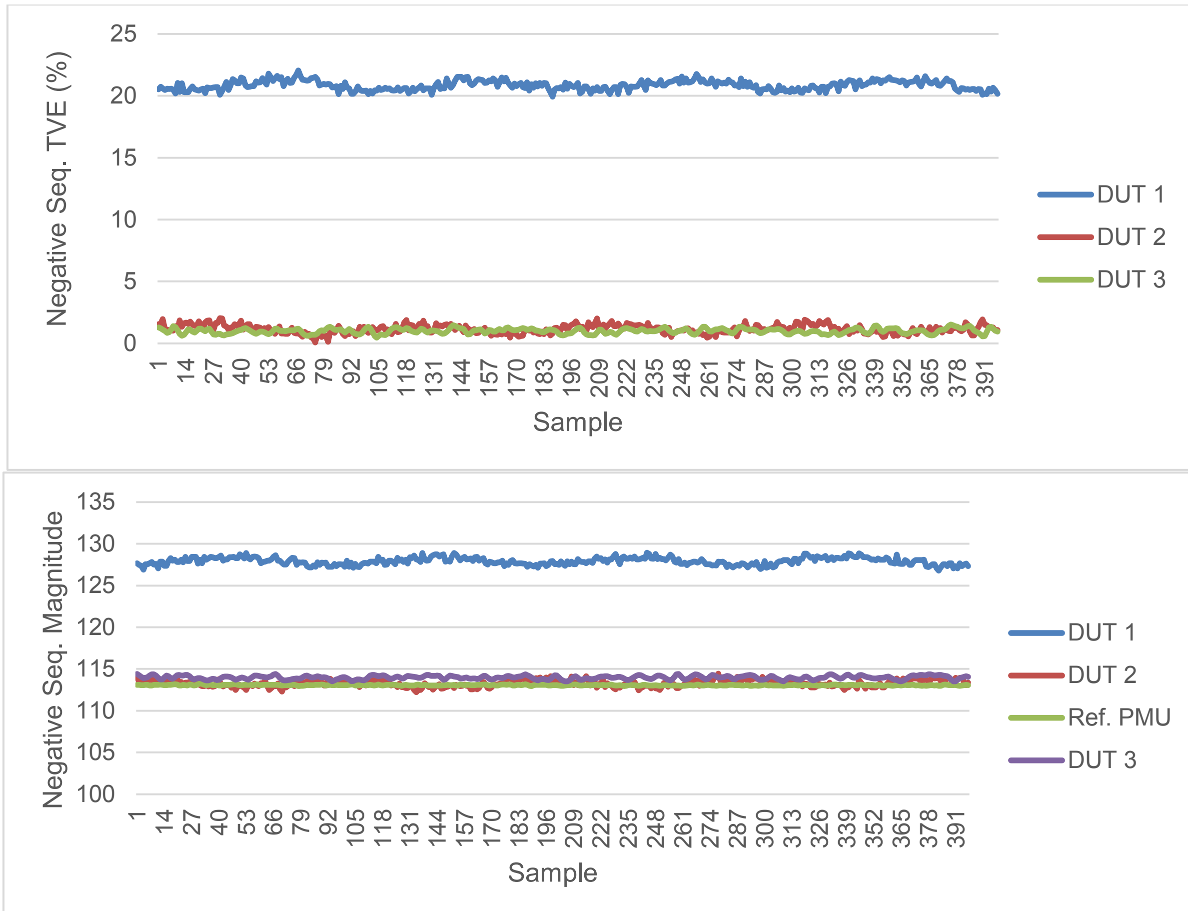


Figure 2-13. TVE and Magnitude of the Negative Sequence (Case 1-1-7)

2.5.2.5.2 Group 2: Frequency Step Test

Group 2 tests are designed for evaluating the DUTs' performance for frequency measurements. For group 2 tests, balanced three phase system voltages and currents were applied to the DUTs. Each of the following test cases was repeated 3 times for test results validation.

Note: Case 1-2-1 was excluded because it is exactly similar to case 1-1-1.

- **Case 1-2-2:** The system frequency was set at 59.7 Hz and the PMU data was captured for 5 seconds. Then, the frequency was changed back to 60 Hz, to continue capturing for another 5 seconds. The following figures show the frequency captured from different devices as well as the FE and RFE. It can be seen from the last figure that the 360 rotation happens within 200 samples. This is consistent with the frequency variation of 0.3 because $200 = \frac{1}{0.3} \times 60$. Furthermore, all PMUs have angle recovery after the frequency gets back to 60 Hz.

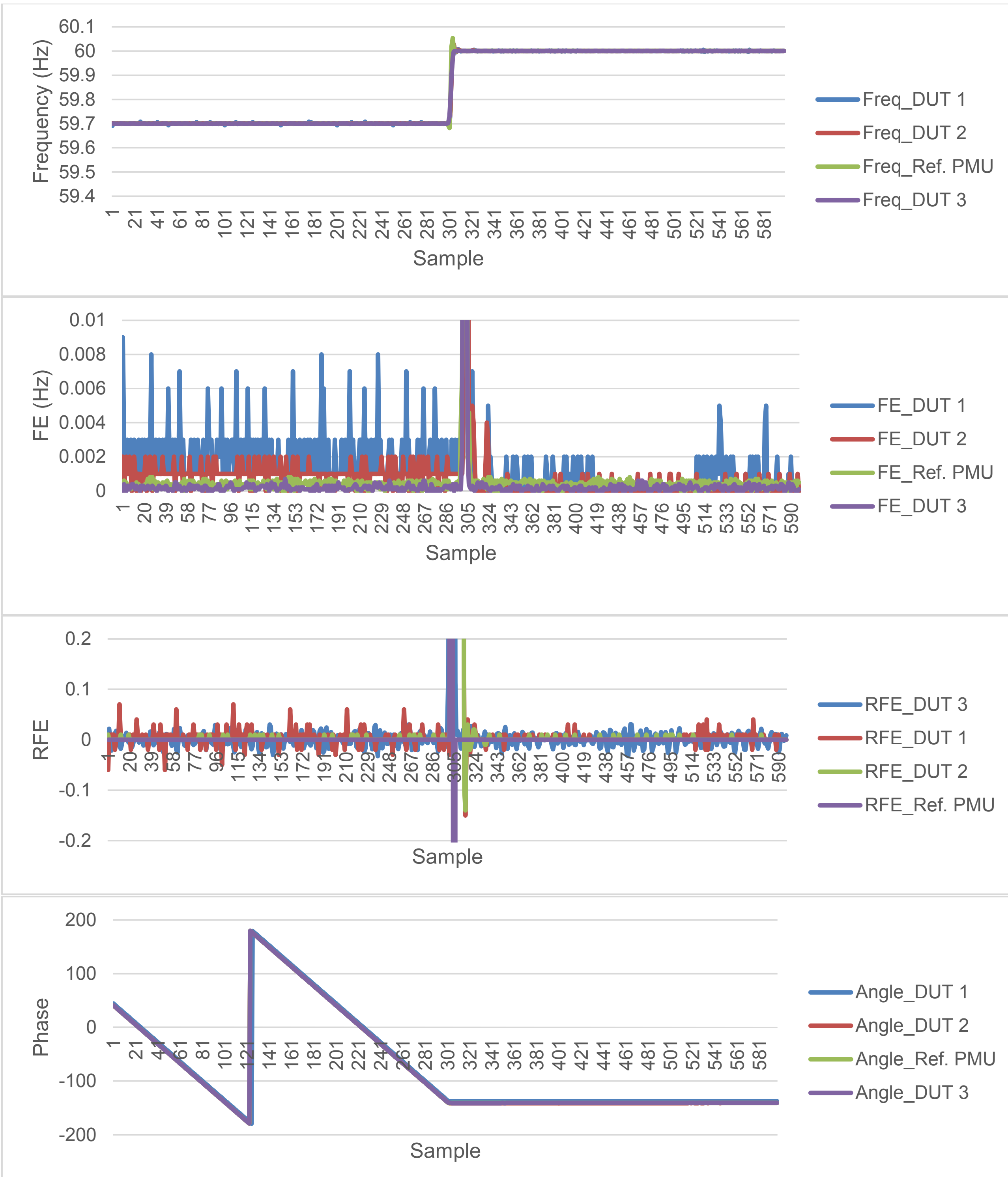


Figure 2-14. Frequency, FE, RFE, and Angle Subsequent to the Step Change of Frequency from 59.7 Hz to 60 Hz (Case 1-2-2)

An interesting observation that we made in this test is that the Arbiter lost the accuracy of its magnitude (for around 0.5 sec) due to the frequency step change. The positive sequence magnitudes from different PMUs can be seen in the following figure.

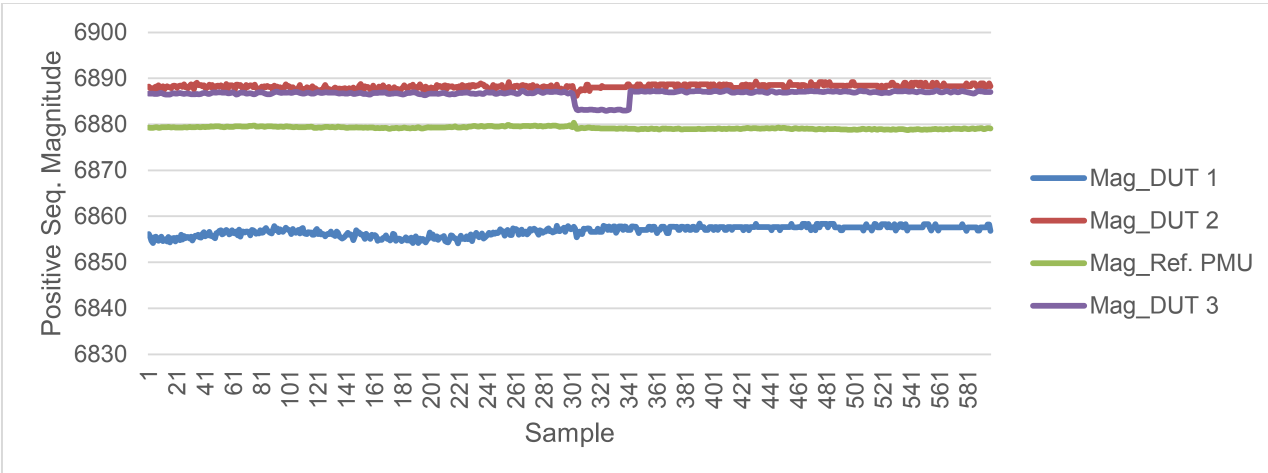


Figure 2-15. Positive Sequence Magnitude Subsequent to the Step Change of Frequency from 59.7 Hz to 60 Hz (Case 1-1-2)

Note: Case 1-2-3 and case 1-2-4 were excluded because of their similarity to the previous results.

- **Case 1-2-5:** The system frequency was set at 61 Hz and the PMU data was captured for 5 seconds. Then, the frequency was changed back to 60 Hz, continue capturing for another 5 seconds. The following figures show the frequency captured from different devices as well as the FE and RFE. The last figure shows that all PMUs have angle recovery after the frequency gets back to 60 Hz.

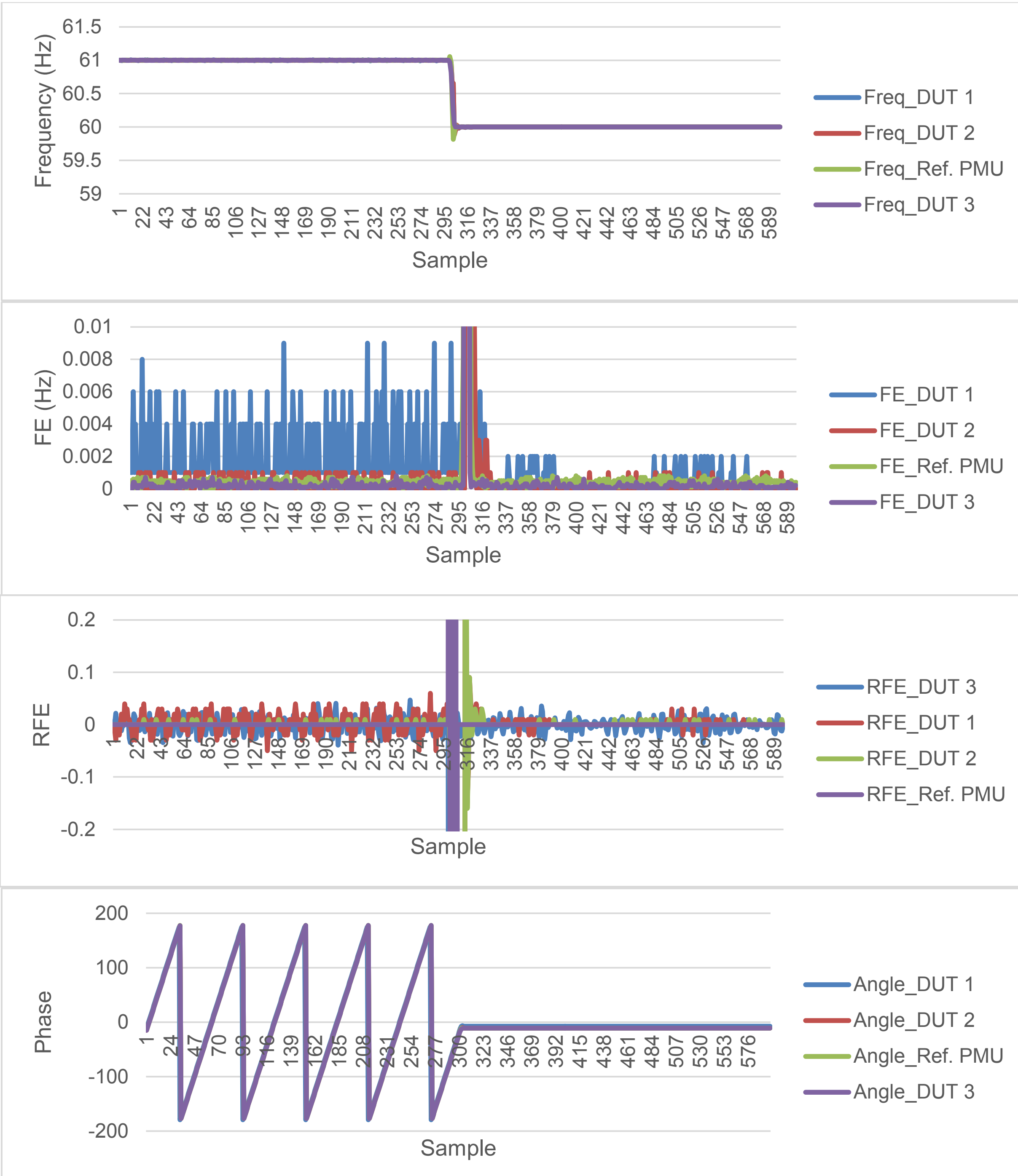


Figure 2-16. Frequency, FE, RFE, and Angle Subsequent to the Step Change of Frequency from 61 Hz to 60 Hz (Case 1-2-5)

The same effect we observed on the previous test case for DUT3 PMU happened for this test case as well, as shown in the following figure. These test cases suggested that the estimated magnitude of the DUT3 could be dependent on the change of the frequency.

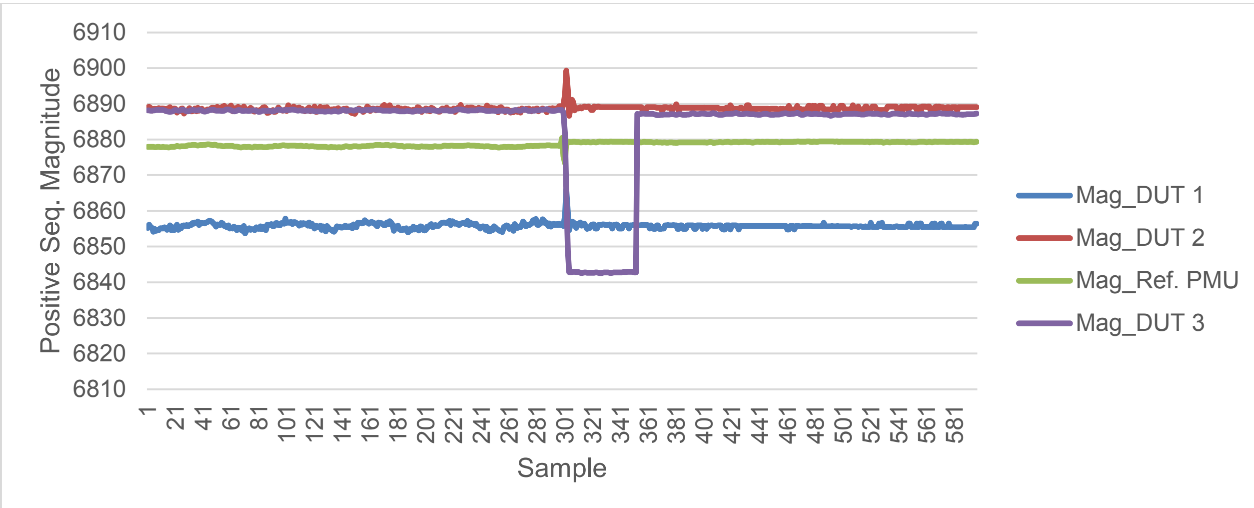


Figure 2-17. Positive Sequence Magnitude Subsequent to the Step Change of Frequency from 61 Hz to 60 Hz (Case 1-2-5)

2.5.2.5.3 Group 3: Harmonic Distortion Test

Group 3 test was designed for evaluating the DUTs' responses to harmonic distortion. For group 3 test, balanced three phase system voltage, current and nominal system frequency was applied as input to the DUTs. Each of the following test cases was repeated 3 times for test results validation. It should be noted that the TVE of Device 1 was very large (around 6%) compared with Device 2 and Device 3 (around 0.1%). Therefore, in order to provide a better comparison between DUT2 and DUT3, the TVE for DUT1 is not shown in this test group.

- **Case 1-3-1:** The system was started at nominal levels for voltage and frequency, while injecting the 5^{th} harmonic with 3% magnitude of voltage and current into DUTs' measurement location. PMU data was captured for 5 seconds. TVE and FE are shown in the following figures.

Figure 2-18. TVE and FE during the Injection of 3% Magnitude of 5th Harmonic (Case 1-3-1)

- **Case 1-3-2:** The system was started at nominal levels for voltage and frequency, while injecting the 5th harmonic with 5% magnitude of voltage and current into DUTs' measurement location. PMU data was captured for 5 seconds. TVE and FE are shown in the following figures.

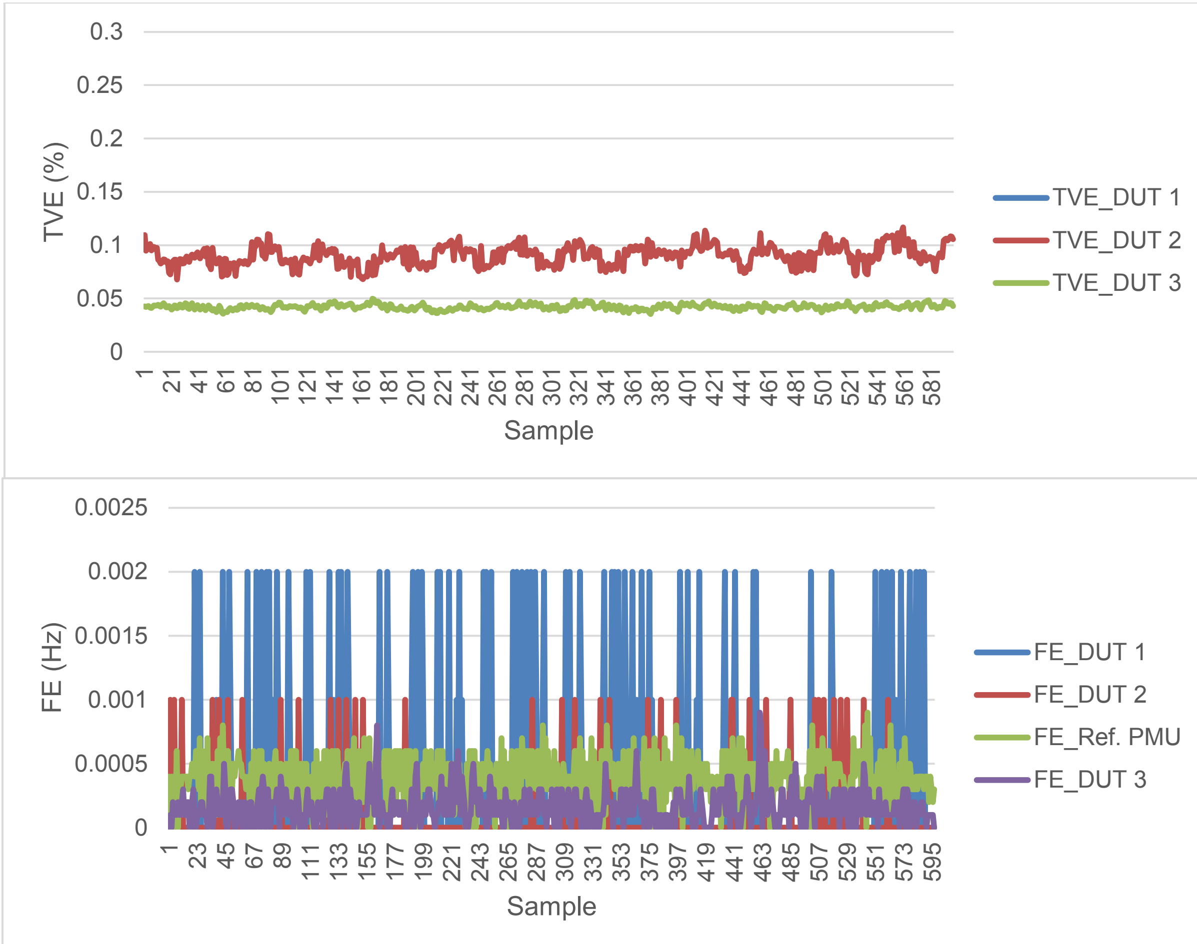


Figure 2-19. TVE and FE during the Injection of 5% Magnitude of 5th Harmonic (Case 1-3-2)

- **Case 1-3-3:** The system was started at nominal levels for voltage and frequency, while injecting the 5th harmonic with 10% magnitude of voltage and current into DUTs' measurement location. PMU data was captured for 5 seconds. TVE and FE are shown in the following figures.

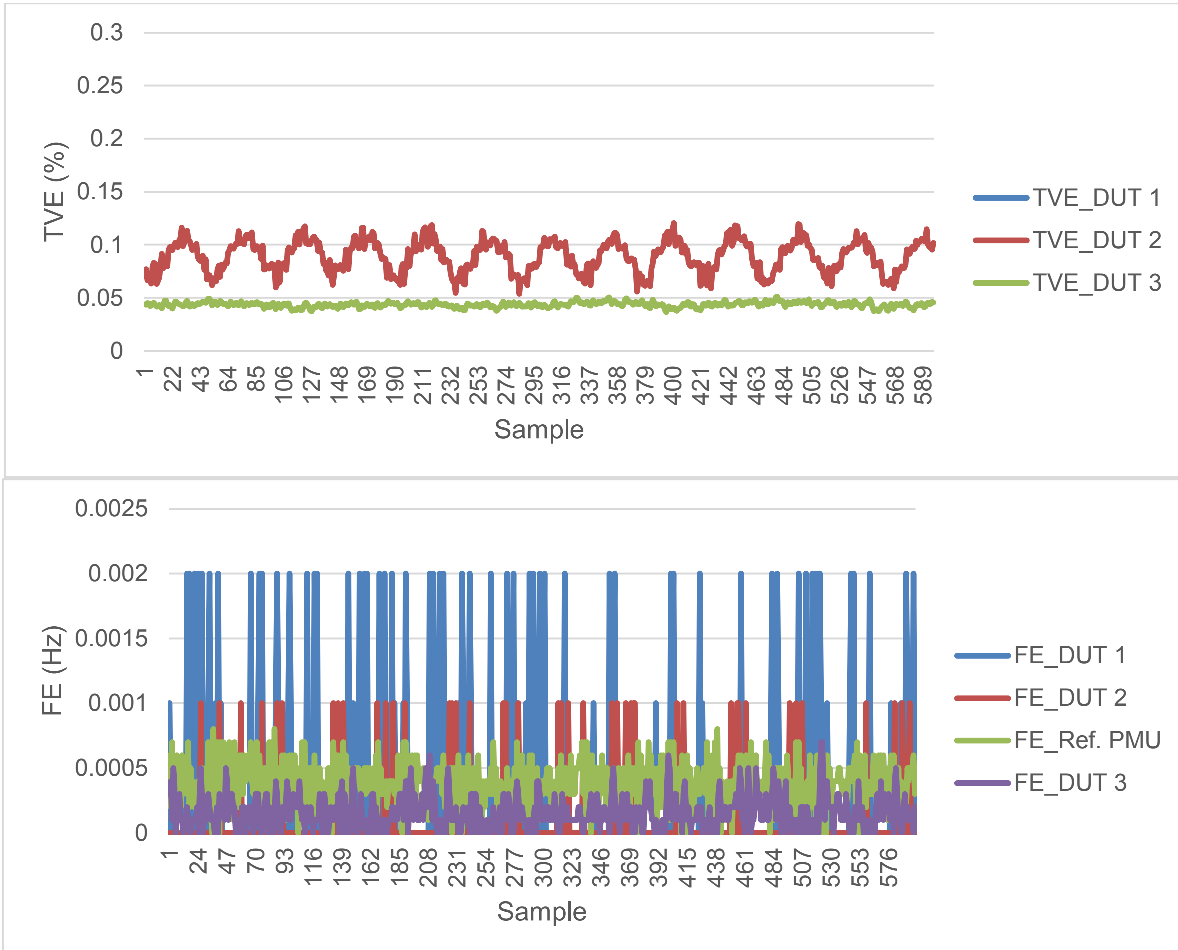


Figure 2-20. TVE and FE during the Injection of 10% Magnitude of 5th Harmonic (Case 1-3-3)

Note: Case 1-3-4, 1-3-5, and 1-3-6 are excluded because of their similarity to the previous results.

- **Case 1-3-7:** The system was started at nominal levels for voltage and frequency, while injecting multiple harmonics (3% of 7th order harmonic, 5% of 5th order harmonic and 10% of 3rd order harmonic) into DUTs' measurement location. A harmonic generator model was used in RTDS circuit model to inject various harmonic orders or a combination of harmonics. PMU data was captured for 5 seconds. TVE and FE are shown in the following figures.

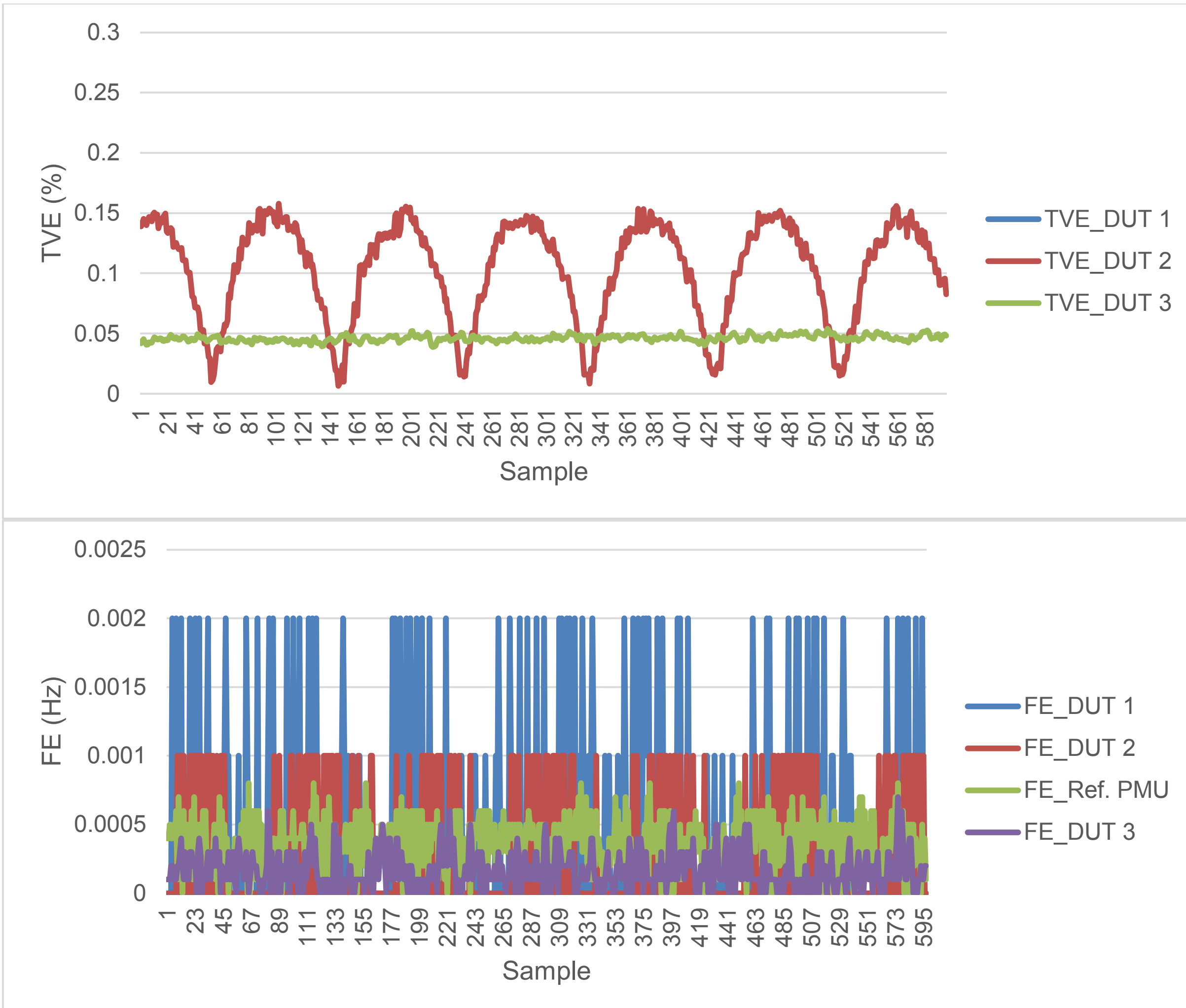


Figure 2-21. TVE and FE during the Injection of Multiple Harmonics (Case 1-3-7)

By comparing the results of this test group, it can be concluded that by increasing the Harmonics the FE increases. Furthermore, the TVE of DUT3 was very robust against harmonics, while the TVE of DUT1 and DUT2 increased by increasing the THD of the voltage.

2.5.2.6 Category 2: Dynamic Performance Tests

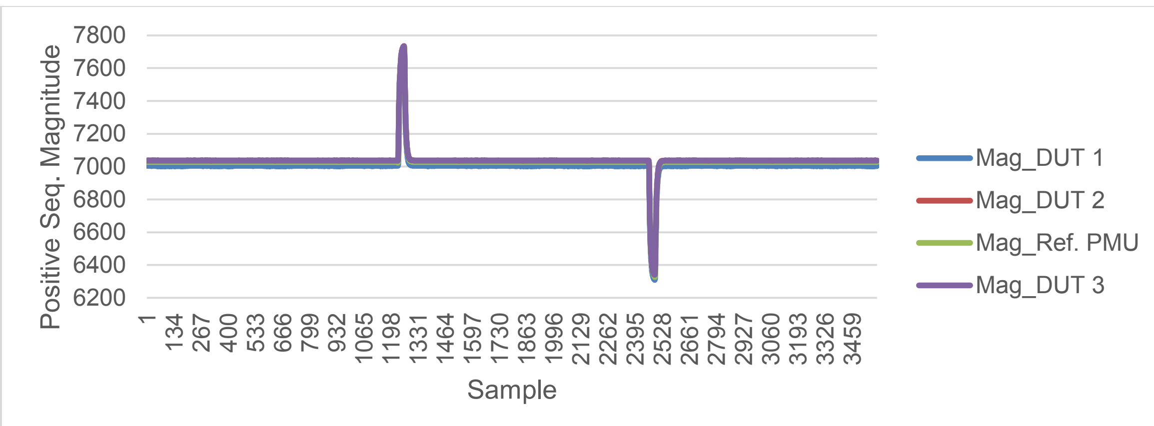
The purpose of this test category is to test the DUTs' performance under dynamic system conditions. The phasor, frequency, and ROCOF estimates obtained from DUTs under different system conditions are compared to the corresponding input measurements. TVE, FE, and RFE is calculated and compared with defined limits in IEEE C37.118.1. Several test groups will be considered in this test category. For category 2 tests, all the test groups were repeated with DUTs' reporting rate set at 60 frames / second and 30 frames / second. However, in this report, only the data at 60 frames/second is reported. Each of the following test cases was repeated 3 times for test results validation

2.5.2.6.1 Group 1: Response to Step Change in Amplitude and Phase

Group 1 tests are designed for evaluating the DUTs' responses to the step changes applied to voltage, current and phase angle. Step changes were applied to voltage, current and phase angle and PMU data streams were captured to calculate TVE.

- **Case 2-1-1:** System voltage and frequency was set at nominal value for 20 seconds. The following actions was applied to the voltage:
  - 10% step voltage increase was applied at the source for 0.5 seconds;
  - Voltage was changed to initial value for 20 seconds;
  - 10% voltage decrease was applied at the source for 0.5 seconds;
  - Voltage was changed to initial value.

The following figures shows positive sequence magnitude and TVE subsequent to the voltage change.



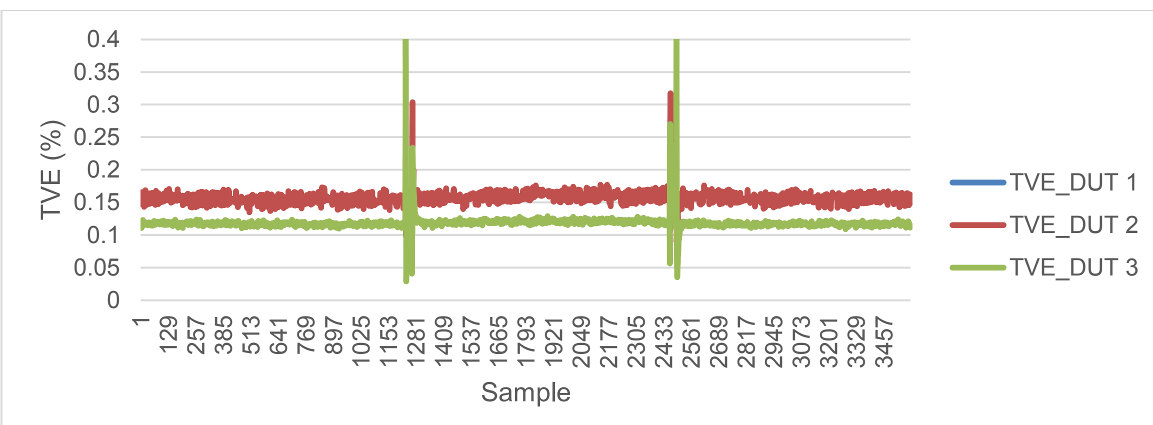


Figure 2-22. Positive Sequence Magnitude and TVE Subsequent to Voltage Changes (Case 2-1-1)

To better compare the dynamic performances, a zoom-in plot of the positive sequence magnitude is shown in the next figure.

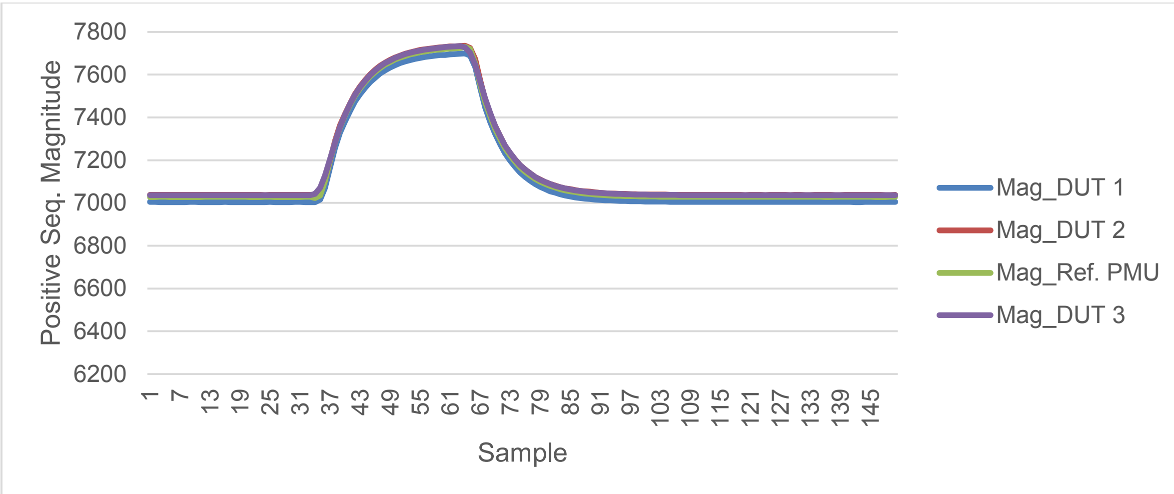


Figure 2-23. Zoom-In Plot of the Positive Sequence Magnitude (Case 2-1-1)

- **Case 2-1-2:** System voltage and frequency were set at nominal value with a 3 phase balanced inductive load with the power factor of 0.75. Load was increased by 10% for 20 seconds and changed back to initial value for 20 seconds. Then, it was decreased by 10% for 20 seconds. The following figures show positive sequence magnitude and TVE subsequent to the load change.

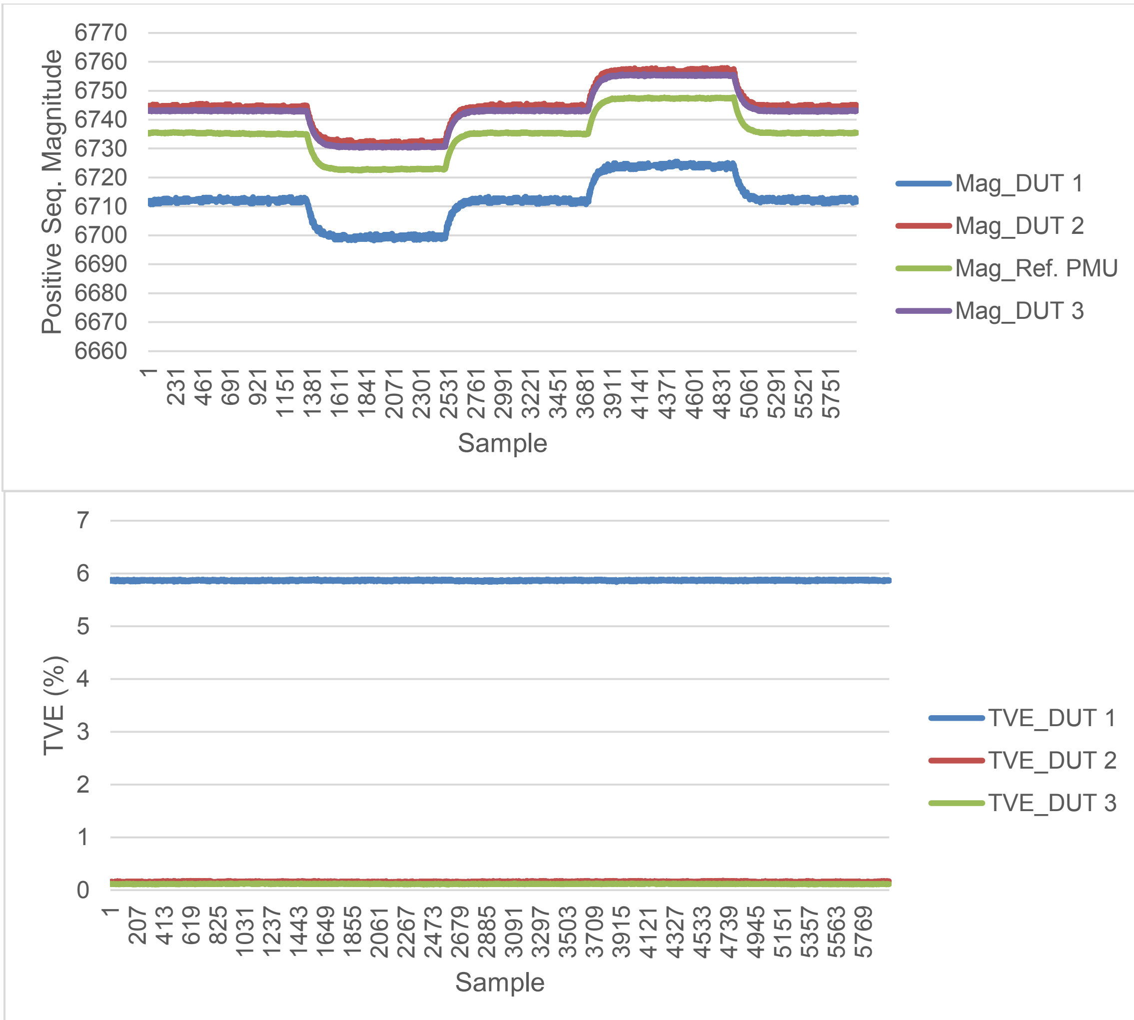


Figure 2-24. Positive Sequence Magnitude and TVE of Voltage Subsequent to Load Changes (Case 2-1-2)

- **Case 2-1-3:** System voltage and frequency were set at nominal value. After 20 seconds, phase angle was increased 45 degrees for all three phases for 0.5 seconds and changed back to its initial value for 20 seconds. Then, phase angle was decreased by 45 degree for all three phases for 0.5 seconds and changed back to its initial value. Note that the phase angle change through the model was used to create sudden vector jump to evaluate DUT responses.

  The following figures shows TVE, magnitude, and phase of the positive sequence subsequent to the voltage change.

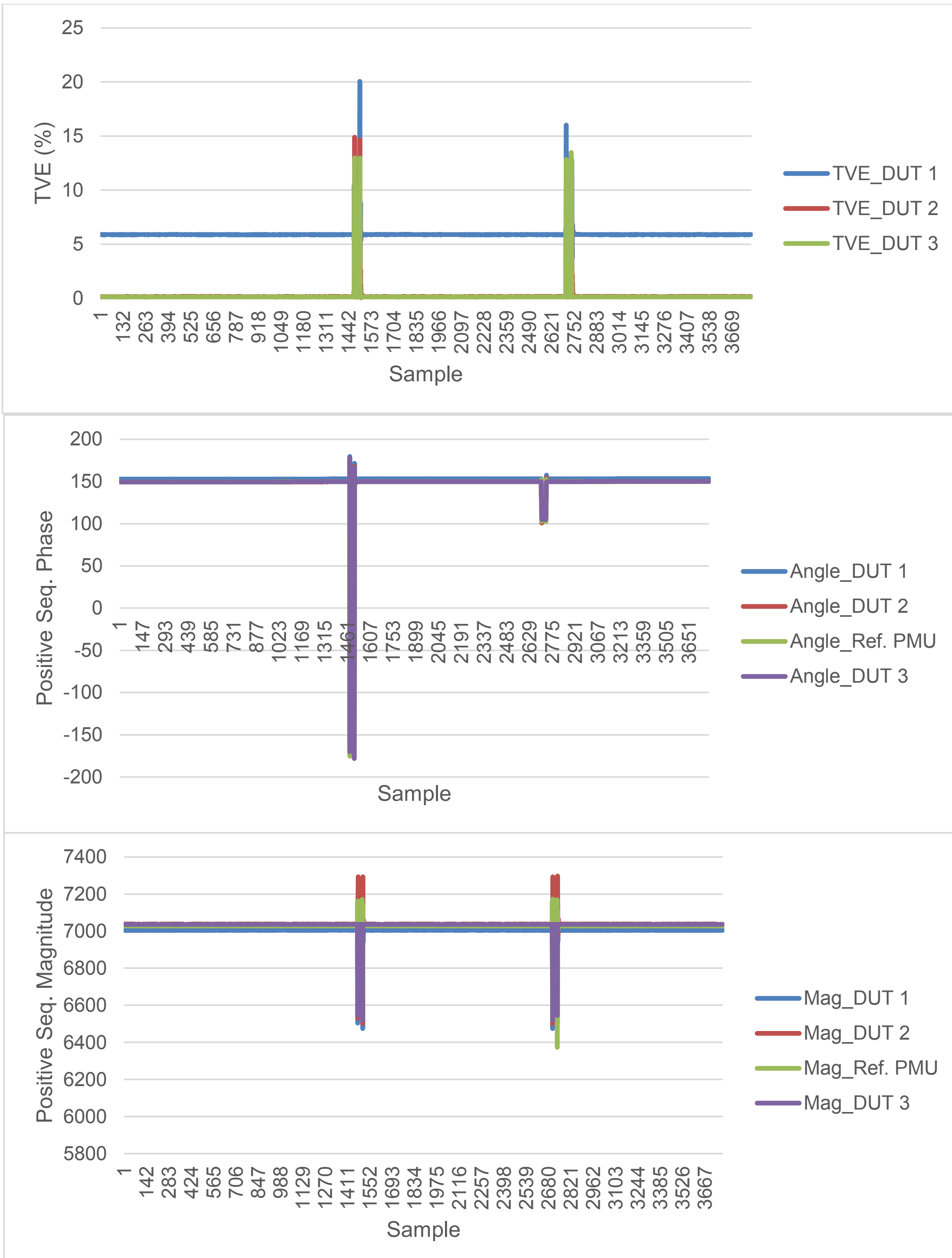
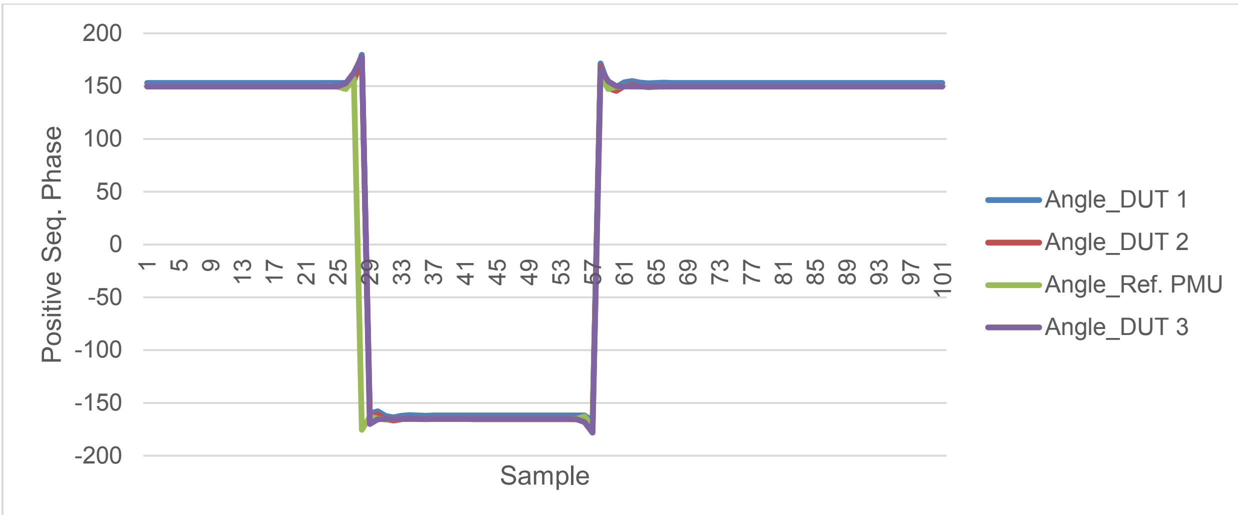


Figure 2-25. TVE, Phase, and Magnitude of the Positive Sequence Subsequent to Phase Angle Changes (Case 2-1-3).

To better compare the dynamic performances, a zoom-in plot of the positive sequence magnitude is shown in the next figure. It can be seen that based on the definition of phase angle, adding 45 degree to the vector has changed the phase angle direction of measurement (150 + 45 = 195 which is greater than 180 degrees).



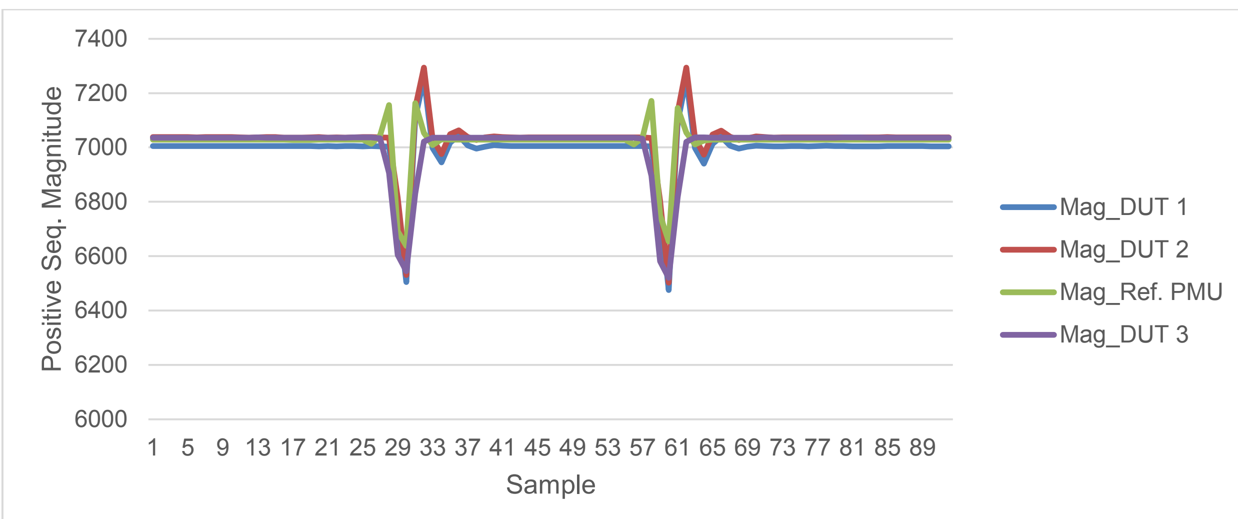


Figure 2-26. Zoom-In Plot of the Phase and Magnitude of the Positive Sequence (Case 2-1-3)

2.5.2.6.2 Group 2: Performance Test during Ramp of System Frequency

This test was designed for evaluating the DUTs' responses to the ramp changes of system frequency. Positive and negative ramps of frequency was applied to the system. PMU data streams were captured to see the DUTs' response.

- **Case 2-2-1:** System frequency was set at 59.7 Hz. After 10 seconds, the positive ramp of frequency was started with the ramp rate of 0.1 Hz/second until reaching 60.3 Hz. Frequency, TVE, and RFE for the test duration can be seen in the following figure.

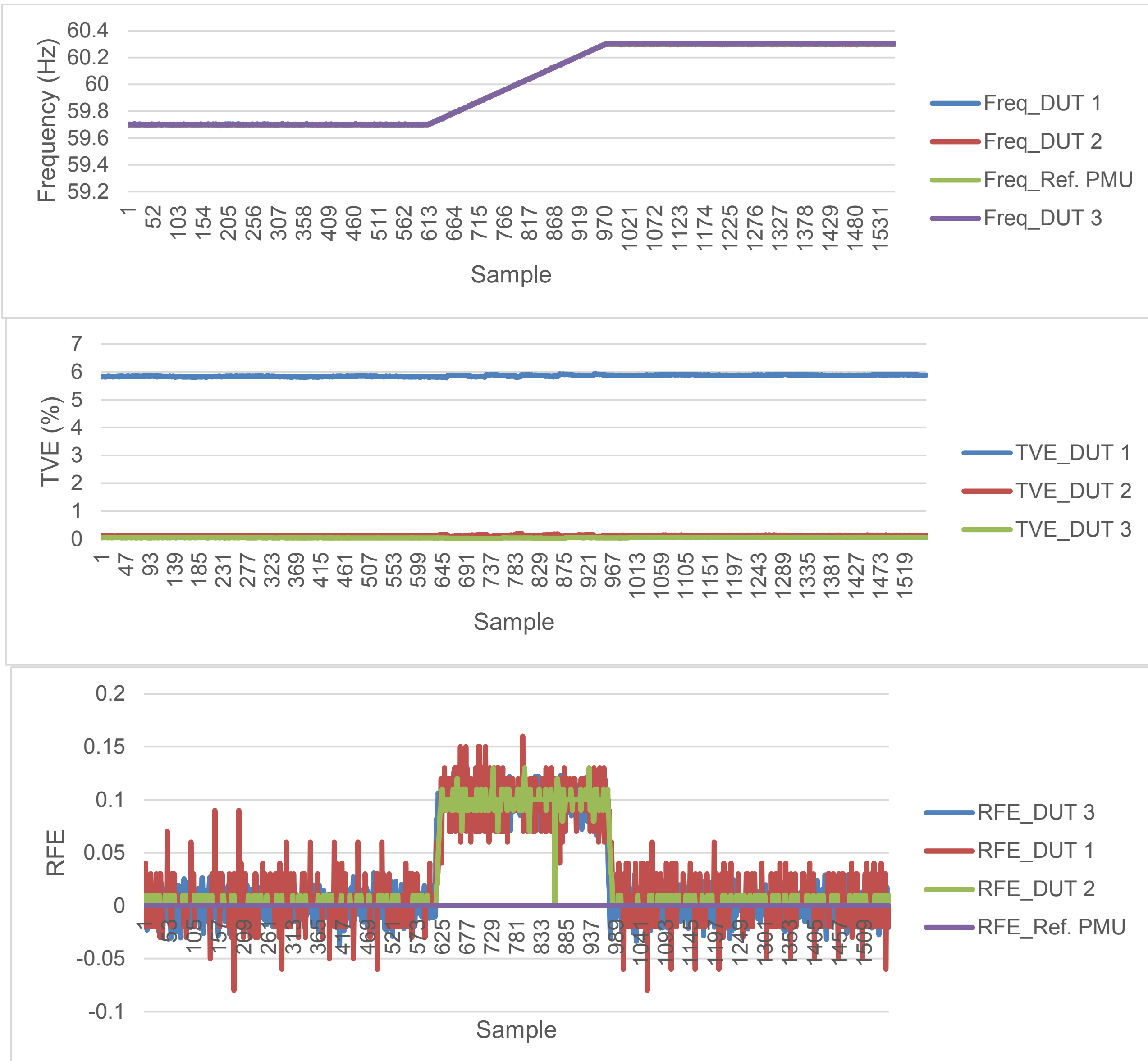


Figure 2-27. Frequency, TVE, and RFE Subsequent to Frequency Ramp (Case 2-2-1)

- **Case 2-2-2:** System frequency was set at 60.3 Hz. After 10 seconds, negative ramp of frequency was started with the ramp rate of 0.1 Hz/second until reaching 59.7 Hz. Frequency, TVE, and RFE for the test duration can be seen in the following figure.

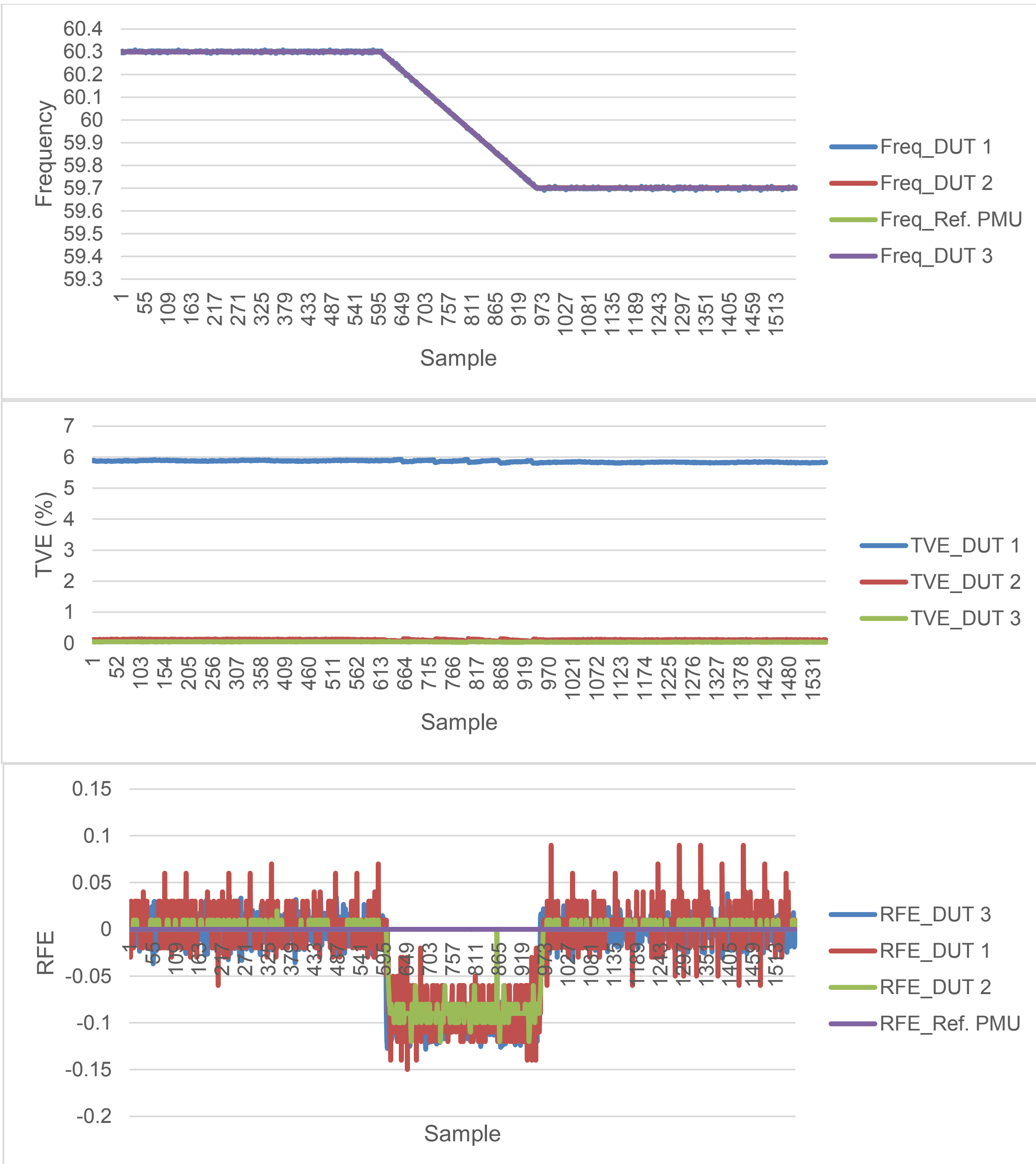


Figure 2-28. Frequency, TVE, and RFE Subsequent to Frequency Ramp (Case 2-2-2)

2.5.2.6.3 Group 3: Performance Test during Capacitor Switching

This group of tests was designed for evaluating the DUTs' performance to record system a sample transient event. This transient event was generated by switching on a capacitor bank. Capacitor switching event was simulated in RTDS and measurements from PMUs were captured and analyzed.

- **Case 2-3-1:** System voltage and frequency were set at nominal value. After 10 seconds, 1.2 MVAR 3 phase cap bank downstream of the DUTs was switched on. Frequency, TVE of voltage, and RFE subsequent to this frequency ramp can be seen in the following figure.

Figure 2-29. TVE and FE Subsequent to Capacitor Switching (Case 2-3-1)

2.5.2.6.4 Group 4: Performance Test during System Faults

This group of tests was designed for evaluating the DUTs' performance to record system fault events. Different types of faults were simulated in RTDS and measurements from PMUs were captured and analyzed.

- **Case 2-4-1:** System voltage and frequency were set at nominal value. After 10 seconds, temporary single line-to-ground fault was applied for 0.2 seconds. The results are shown below.

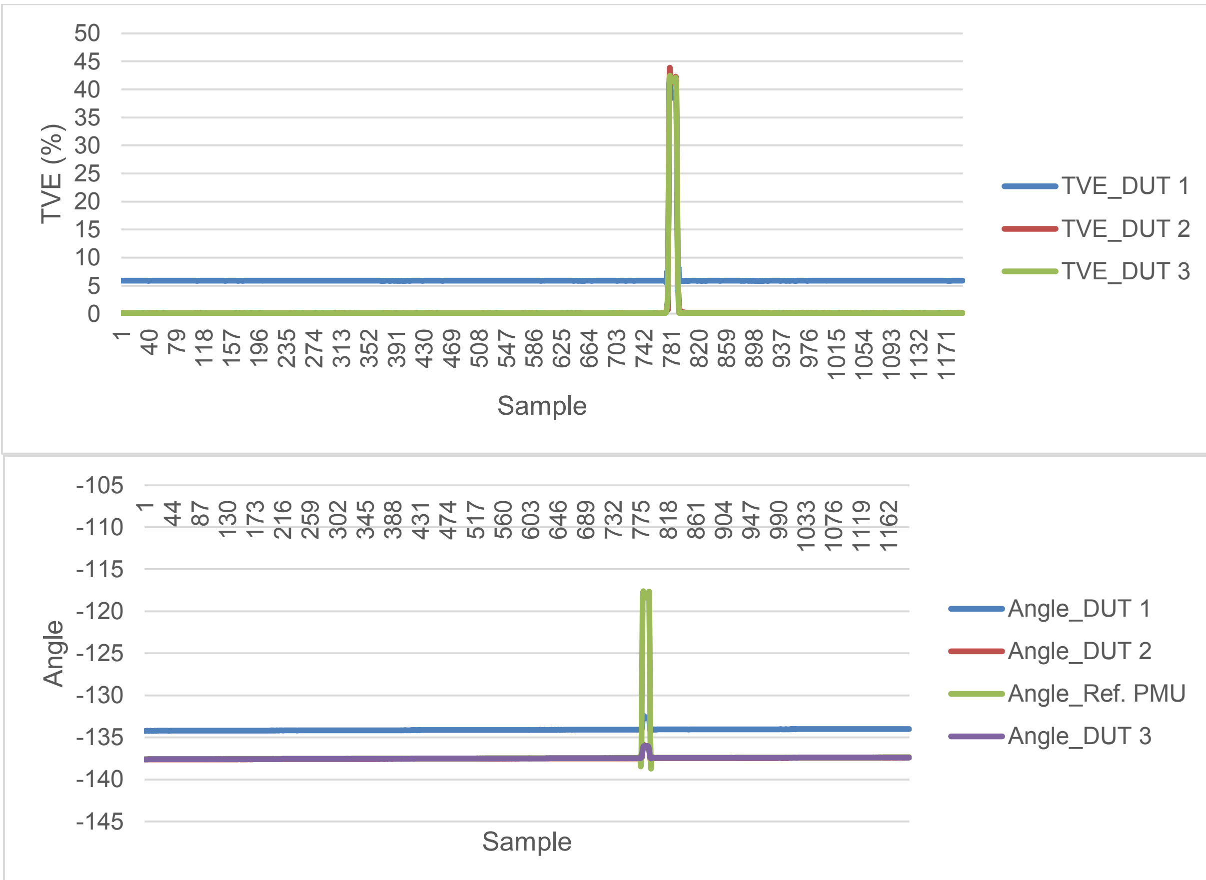


Figure 2-30. TVE of Voltage and Angle Subsequent to Single Line-to-Ground Fault (case 2-4-1)

- **Case 2-4-2:** System voltage and frequency were set at nominal value. After 10 seconds, temporary line-to-line fault was applied for 0.2 seconds. The results are shown below.

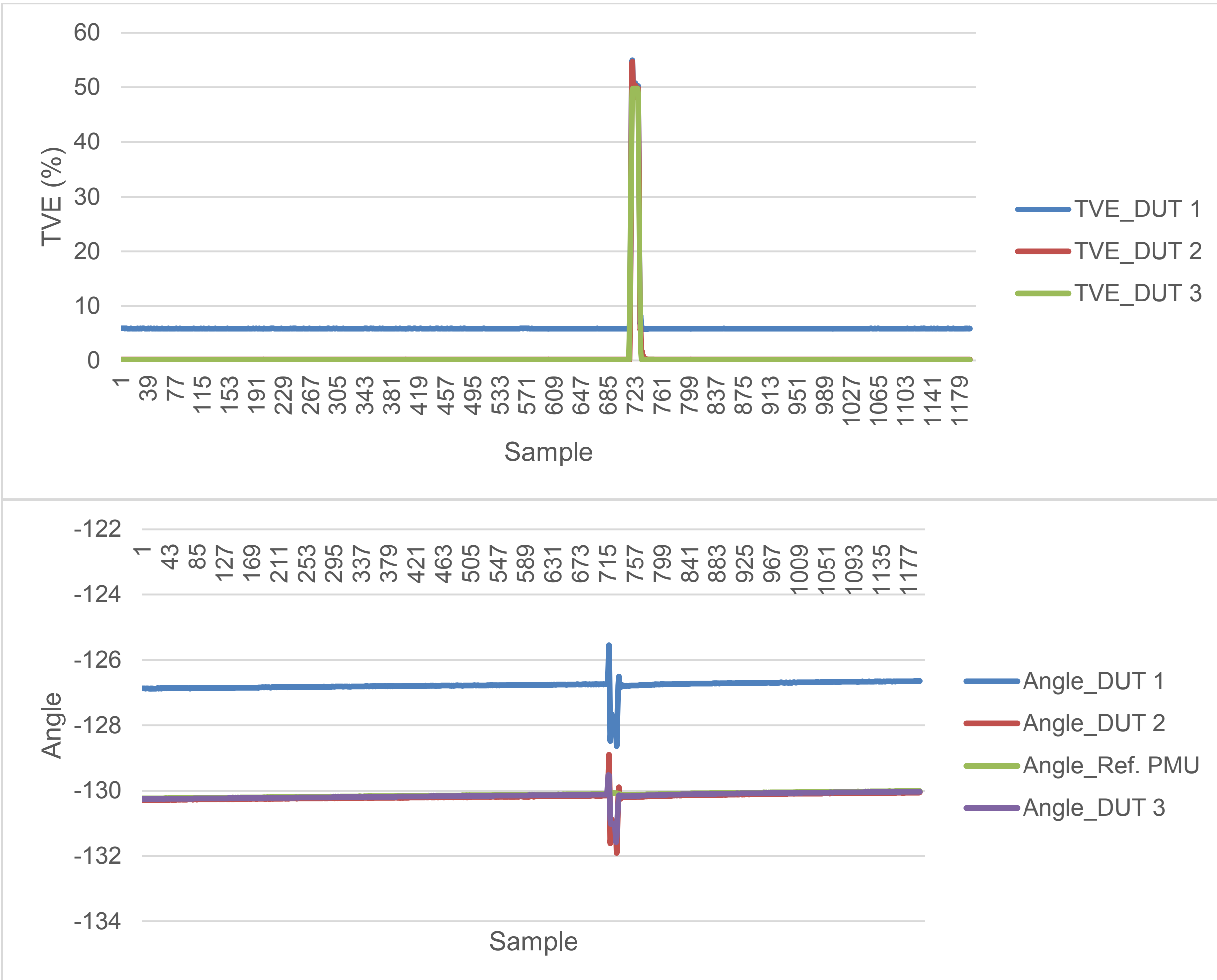


Figure 2-31. TVE and angle subsequent to line-to-line fault (2-4-2).

Case 2-4-5: System voltage and frequency were set at nominal value. After 10 seconds, temporary line-to-line fault was applied for 1 seconds. The results are shown below.

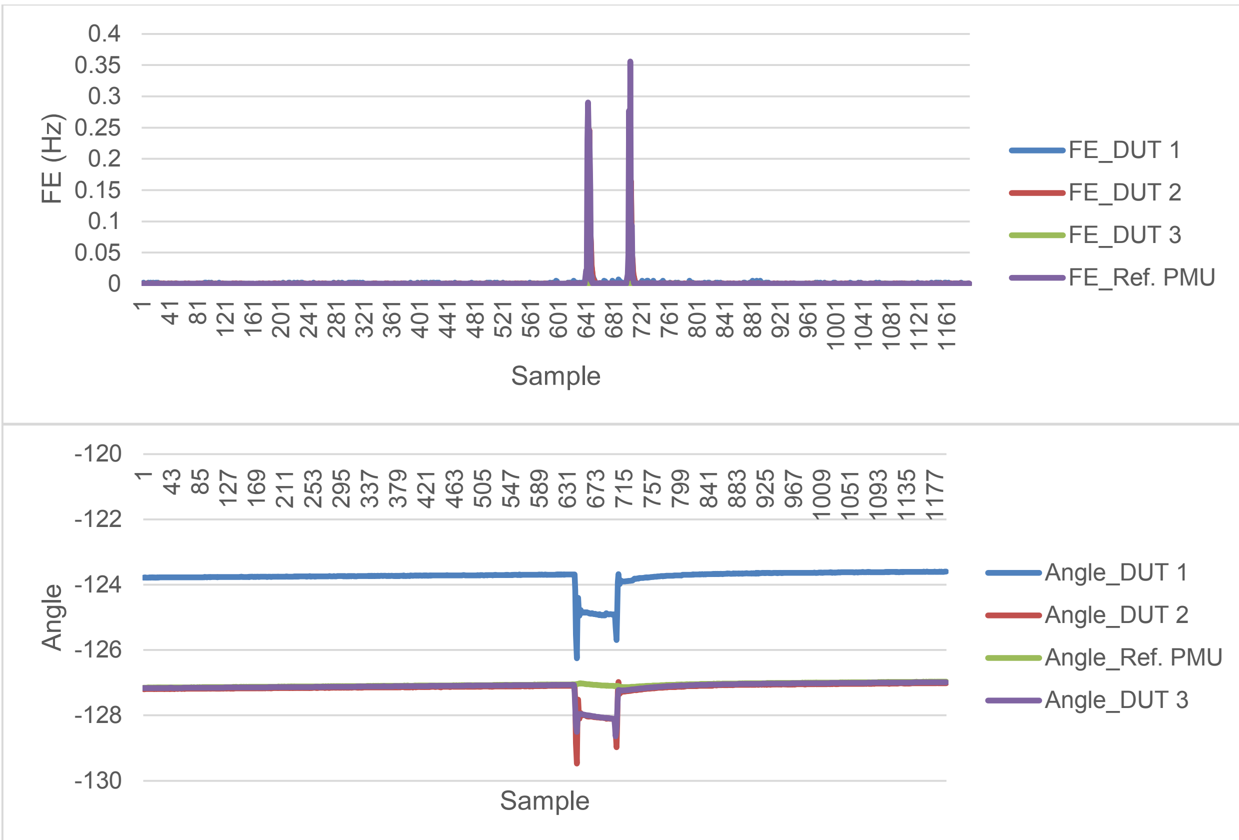


Figure 2-32. FE and angle subsequent to line-to-line fault (2-4-5).

An interesting observation from this test was that there is no change in the phase angle estimation of the reference PMU during the fault, while the other devices had a certain phase shift during the fault. The fault was long enough so that all the PMUs converge to the new values during the fault; therefore, it was expected to have a zero TVE during the fault. However, we cannot see zero TVE during this event. The reason is that it seems that the reference PMU was not working properly.

- **Case 2-4-6:** System voltage and frequency were set at nominal value. After 10 seconds, temporary three-phase fault was applied for 1 seconds. The results are shown below.

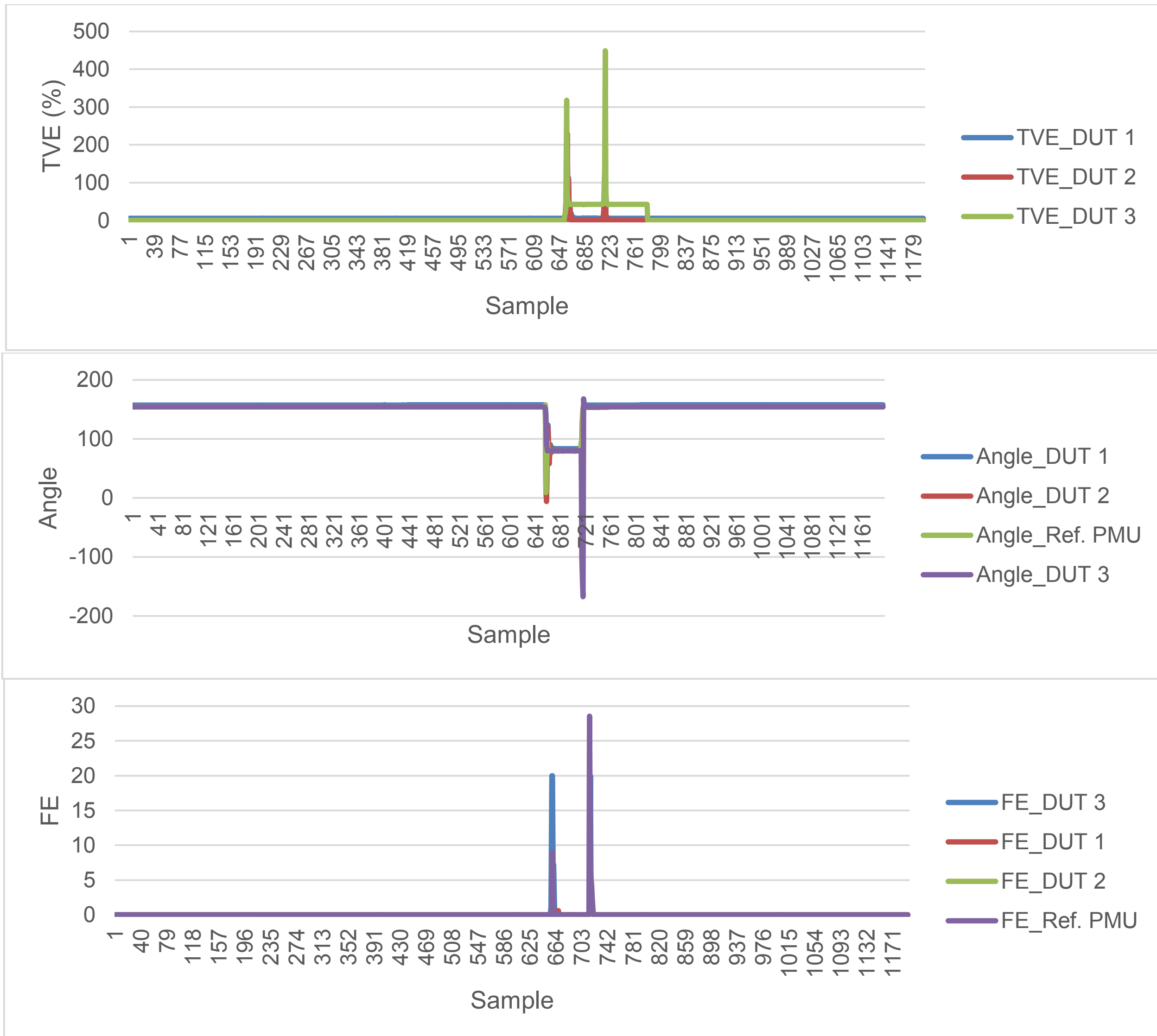


Figure 2-33. TVE, angle, and FE Subsequent to 3-Phase Fault (Case 2-4-6)

It can be seen that the TVE of the DUT3 remains high even after the clearance of the fault. The reason is that, as it can be seen in the following figure, the arbiter is not able to correctly estimate the magnitude of the positive seq. voltage after the fault for about 1 second.

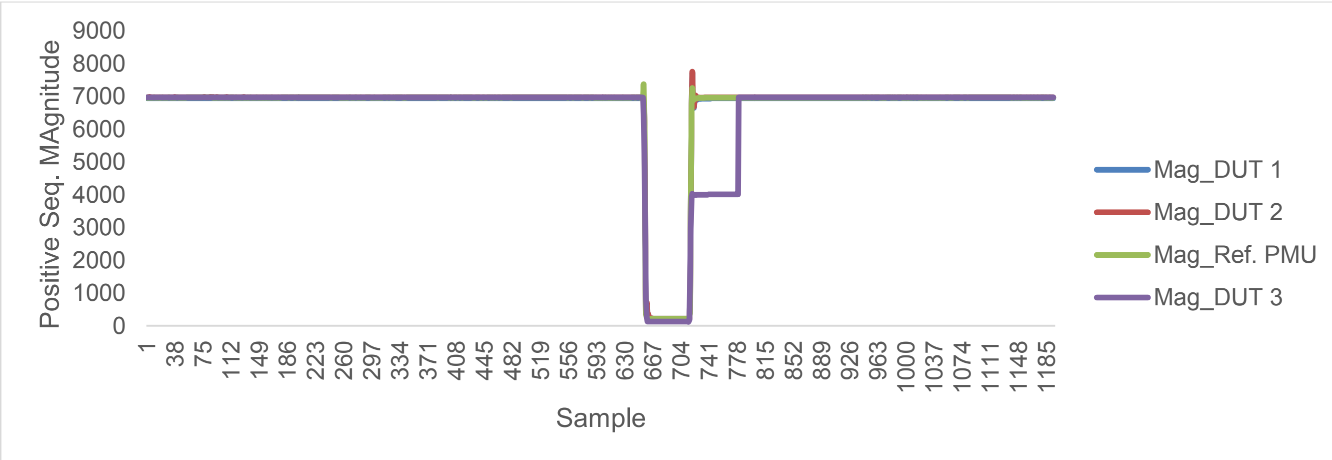


Figure 2-34. Voltage Magnitude during the Fault (case 2-4-6)

2.5.2.7 Category 3: Analog and Digital Data Streaming Capability

In this section, the DUT capability for streaming locally measured power quality parameters or any parameter that is calculated at device level using mathematical and logical blocks is investigated. It should be noted that reference PMU is not listed here because its measurements and capabilities depend on the added module to the device. The following table summarizes the available phasors through IEEE C37.118 Synchrophasor protocol from different PMUs.

Table 2-14. Available Phasors in Different PMUs

Phasor	DUT1	DUT2	DUT3	DUT4
V_a	☑	☑	☑	☑
V_b	☑	☑	☑	☑
V_c	☑	☑	☑	☑
V_s	☒	☑	☒	☒
I_a	☑	☑	☑	☑
I_b	☑	☑	☑	☑
I_c	☑	☑	☑	☑

Phasor	DUT1	DUT2	DUT3	DUT4
I_N	✓	✓	✗	✗
V_1	✓	✓	✓	✓
V_2	✗	✗	✓	✗
V_0	✗	✗	✓	✗
I_1	✓	✓	✓	✓
I_2	✗	✗	✓	✗
I_0	✗	✗	✓	✗

In addition to the phasors, IEEE C37.118 provides the capability for the analog and digital data streaming. The following table summarize this capability for different PMUs.

Table 2-15. Available Analog and Digital Data Streams in Different PMUs

Data Stream	DUT1	DUT2	DUT3	DUT4
Assignable Analog Value	4	4	0	0
Unassignable Analog Value	0	0	20	0
DSP Trigger Event input	16	16	32 4	8

It should be noted that:

a. PMU in DUT1 and PMU in DUT2 can stream 4 assignable analog values and 16 digital values.

b. PMU in DUT3 can stream 20 analog values through PMU. However, all of these analog values are pre-defined and cannot be changed. It should be noted that the triggering logic in PMU Device 3 can just compare the analog values with some limits, while in PMU in DUT1 and DUT2 can perform mathematical and logical operations.

c. PMU in DUT3, depending on the settings sends either the voltage and current abc-phasors or voltage and current positive sequence phasors, while other devices sends at least both abc-phasors and positive sequence phasor. However, this PMU does not provide analog value streaming; however, it can stream up to 8 digital values.

2.5.3 Type Test Conclusions

Based on the steady state performance, dynamic performance, and digital/analog capability of four tested PMUs the following can be concluded:

1. DUT1

    a. Based on the test results, it was shown that it added around 3 degrees of error in phase angle; however, it has the capability to be calibrated.

    b. It showed a very good dynamic performance. It never lost the convergence due to the rapid changes in the voltage, frequency, or phase angle.

    c. It can stream 4 analog values and 16 digital values. There is a lot of flexibility on defining a logic for the digital value or a calculation for analog value.

    d. Device configuration is straightforward.

2. DUT2

    a. Based on the results, it was shown that it had less than a 0.5degree error in phase angle. Furthermore, it has the capability to be calibrated.

    b. It showed a very good dynamic performance. It never lost the convergence due to the rapid changes in the voltage, frequency, or phase angle.

    c. It can stream 4 assignable analog values and 16 digital values. There is a lot of flexibility on defining a logic for the digital value or a calculation for analog value.

    d. Device configuration is straightforward.

3. DUT3

    a. It had shown less than a 0.5-degree error in phase angle. However, it has the capability to be calibrated.

    b. It showed poor dynamic performance. In few case studies, it was observed that the device lost the convergence for few seconds after a transient.

c. It can stream 20 pre-defined analog values and 36 digital values. The analog values are pre-defined and cannot be changed. Furthermore, very basic logics can be defined for the digital value.

d. Device configuration is straightforward.

e. It can operate as a PQ meter as well.

4. DUT4

a. The test results showed that it had around 2 degree error in phase angle. However, this error was increased to 45 degrees in case of the utilization of the extension module due to the communication delay between the extension module and relay. Currently, the phase angle doesn't have calibration capability. However, the discussions with vendor had suggested that there will be future firmware upgrade to accommodate the issue.

b. It cannot stream any analog value.

c. It can stream up to 8 digital value.

d. Device configuration is difficult.

2.6 Demo System Setup and Customer System Integration

Based on the proposed approach, various data sources have been employed to monitor and visualize the status of the selected circuits of the SDG&E distribution systems. More details about this are provided earlier in this report. One aspect of the project has been to look at the actual field data, both in real-time form, but also the data and information retrieved from historical data base, power quality meters, as well as from other sources such as reliability department.

Another aspect of the project has been to look at the simulated environment that would enable to add additional devices to models of selected circuits, and enable monitoring and analysis of use case that are not available in the actual distribution network.

The diagram shown in Figure 2-35 below describes at high level this hybrid approach. There are two parallel data streaming and monitoring paths: 1) field data streaming path through substation PDC, and 2) simulated data streaming from laboratory through a dedicated PDC in the lab. The data from both paths gets ultimately collected at control center for processing and visualization.

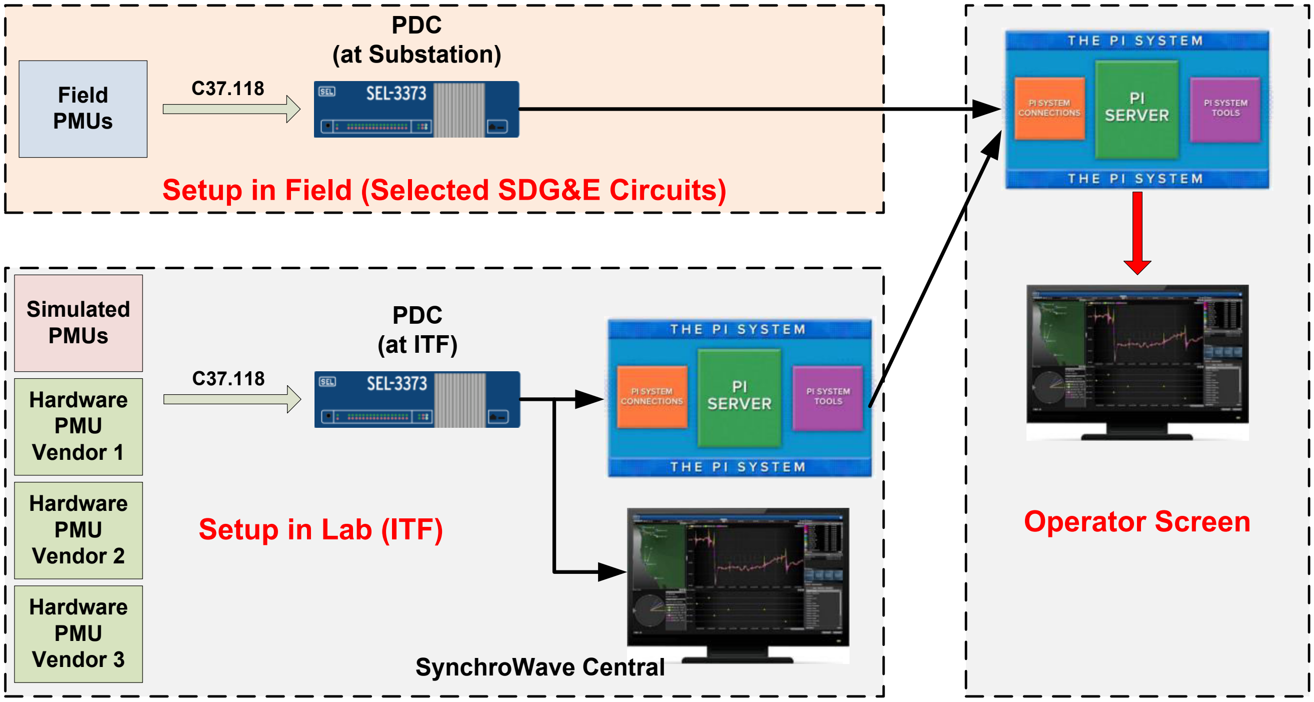


Figure 2-35. High level architecture for of the demonstration system

2.6.1 System architecture that employs field data

As described earlier in the report, field data can come from various devices, such as PMUs, IEDs, RTUs (remote terminal devices for SCADA), AMIs, power quality meters, as well as from PI historian, or other offline sources in form of reports or additional documents. Figure 2-36 shows a high-level architecture that has been used for this purpose. Visualization and analytics box in this diagram was used for post processing data to calculate performance indices and/or to create data infeed for trends and histograms, as described in the visualization system functional requirements and the six proposed use cases.

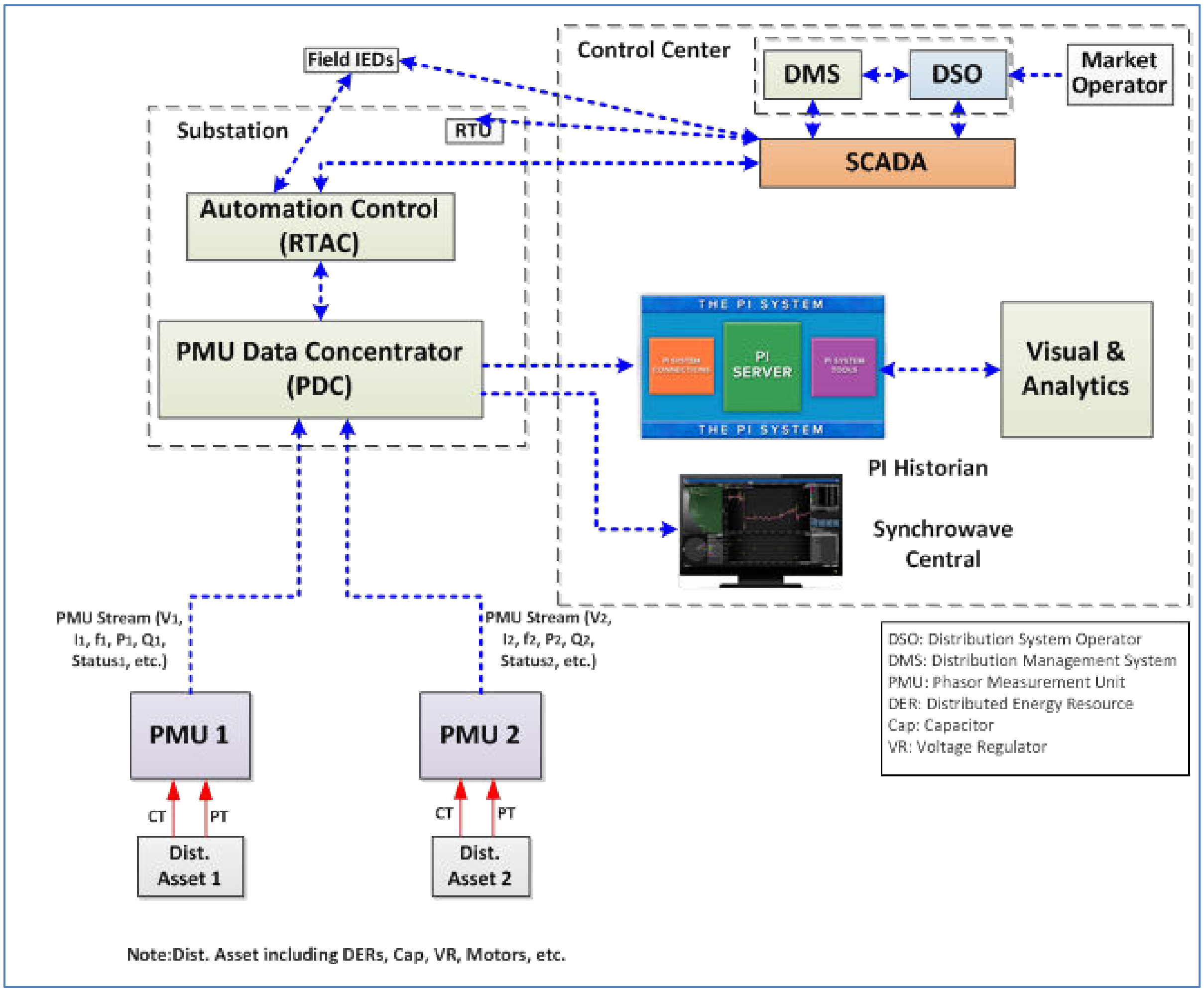


Figure 2-36. High level system architecture for integration and visualization of field data and information

One of the challenges in implementation of this system was to resolve how to combine various visualization and data platforms in one, user friendly system. For instance, PMU data is managed using a synchrophasor management system, power quality is managed by the technology that can process and visualize data such as harmonics, distortion, swell and sag, and similar; and, historian system has its own platform to manage, process and visualize the measurements and processed results. In addition to this, some of the requirements were to have access to reliability data, and these are managed by a separate group at SDG&E.

Also, one needed having in mind that the main anticipated users of this system would be system operators and engineering analysis group, as well as planning group, to a lesser extent.

This challenge of fusing and integration of diverse data set was addressed by creating a dashboard within Geospatial Information System (GIS) as a convenient means that provides geographical information about the circuits' infrastructure.

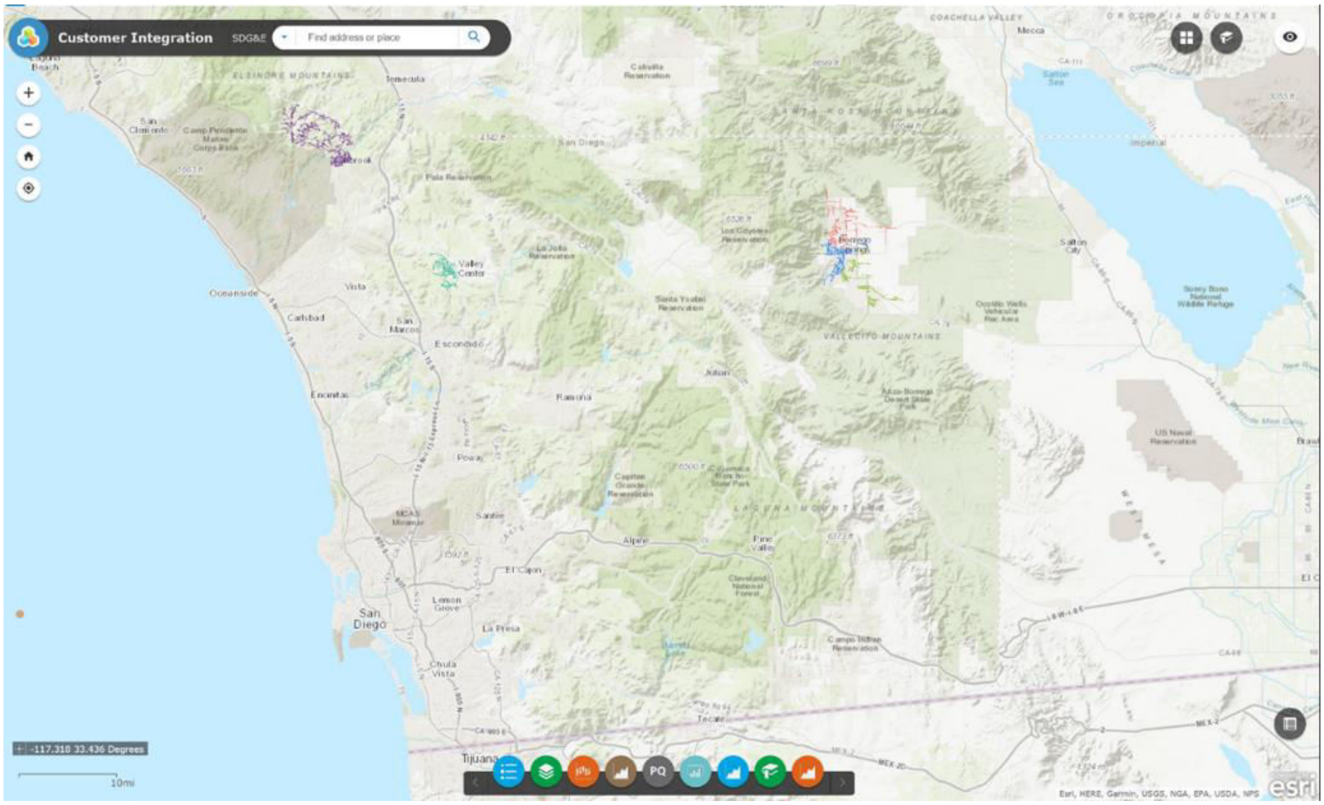


Figure 2-37. Main visualization system implementation dashboard

The SDG&E team has successfully implemented all requirements and the results are presented in the following sections.

2.6.2 System Test Setup at ITF Lab

The general layout of the testbed has been illustrated in Figure 2-38. The testbed consists of the following components:

- **Real-time digital simulator (RTDS)** – which is used for the representation of circuit 1 with all major controllable assets modeled.
- **GTNET PMU** – which is used for phasor data measurement and streaming of PMU1 to PMU8 in the simulation environment.
- **GTAO1 and GTAO2** – analog output cards that are used to send the low level voltage and current signals to the physical PMU devices.
- **Amplifier** – which is used to amplify low level voltage/current signals from RTDS to the secondary level for injection to the physical PMU devices (it should be noted that some physical devices use low level signals directly).
- **PMU Device 2** used for phasor data measurement and streaming of PMU9.
- **PMU Device 3** used for phasor data measurement and streaming of PMU10.
- **PMU Device 4** used for phasor data measurement and streaming of PMU11.

- **PMU Device 1** used for phasor data measurement and streaming of PMU12.
- **Real-Time Automation Controller unit** used for the processing of the available PMU data
- **GPS clock** used for time synchronization of RTDS, Automation Controller and PMU devices.
- **A PDC Software** used for PMU and Automation Controller data aggregation and time alignment for downstream applications
- **PMU Visualization Software** used for translating PMU data into visual information.

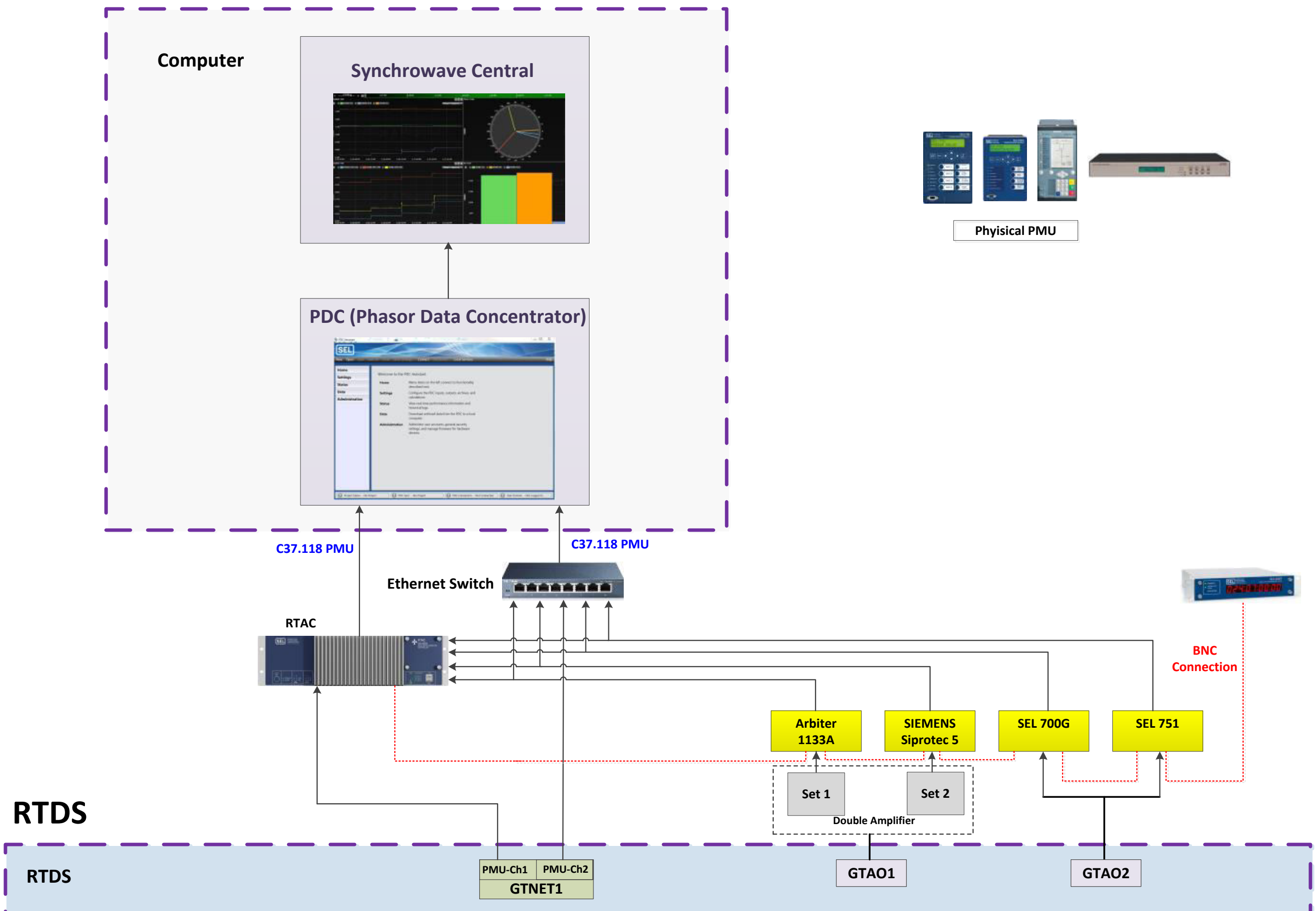


Figure 2-38. Test System Single Line Diagram for laboratory testing

3 Pre-Commercial Demonstration Results with Field data

This section provides the results of demonstrations on the capabilities of measurement, monitoring and visualization platform of the system described earlier in this report. The implementation was based on the requirements developed in six use cases and the proposed (extensive) list of visualization requirement.

3.1 PI Coresight Screens

The main system dashboard (Figure 2-37) developed for this project is a web based GIS application, with a series of widgets/buttons, each representing a separate application of visualization environment. One of the widgets calls up a PI Coresight dashboard, as shown in Figure 3-1.

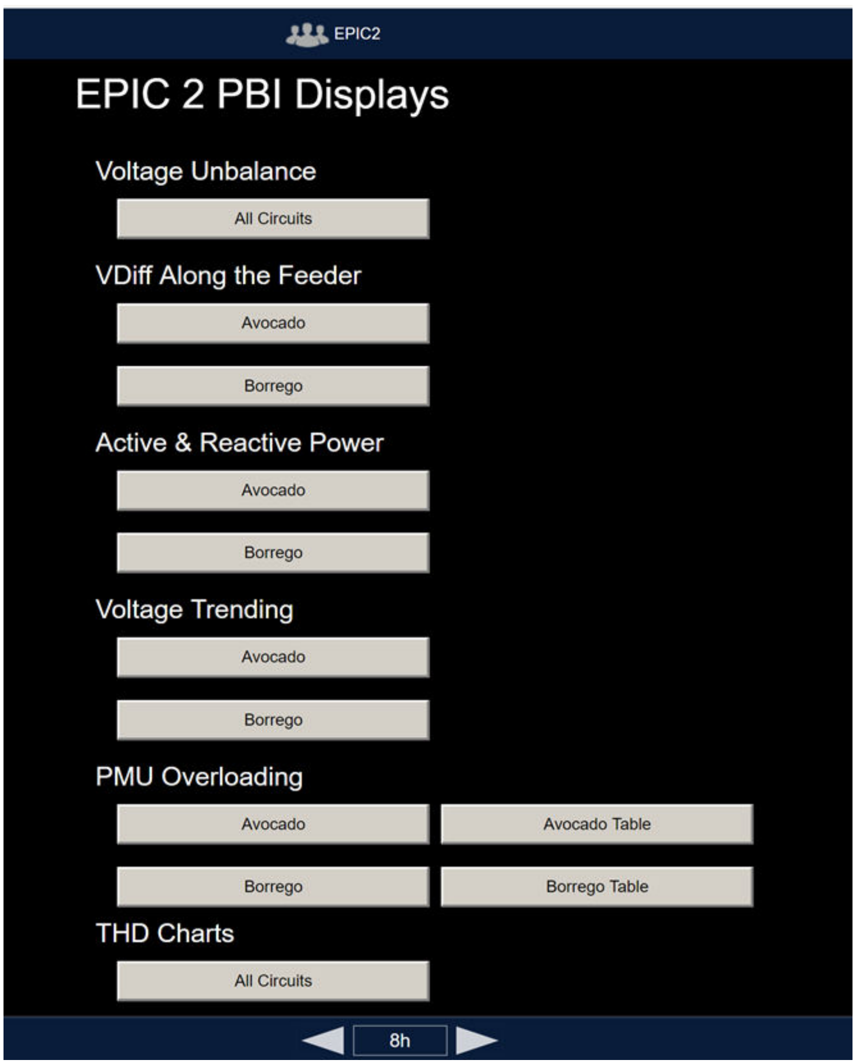


Figure 3-1. An example of a dashboard that utilize historical data base

As shown in this figure, several screens (such as Voltage Unbalance, PMU Overloading, THD charts, and etc) have been integrated in the PI Coresight dashboard. The remaining of the section provides example of various screens demonstrated.

The following figure shows visualization of voltage unbalanced factor using positive and negative sequence components at each PMU location ($\frac{V_1}{V_2}$). The values are calculated every 30 seconds in the PI system. The result are displayed on this PI Vision screen with limit lines at 3% and 10%. By using a multi-state symbol, the bars on the chart will turn to orange and then to red as they exceed the two thresholds.

Figure 3-2. Monitoring of voltage unbalance factor

The following screen shows voltage total harmonic distortion (THD) data being displayed on a bar chart with limit lines. The data comes through the SCADA system, so updates occur every 2-5 seconds. By selecting a THD percentage value, a trending chart is displayed with a configurable time range as shown in Figure 3-4.

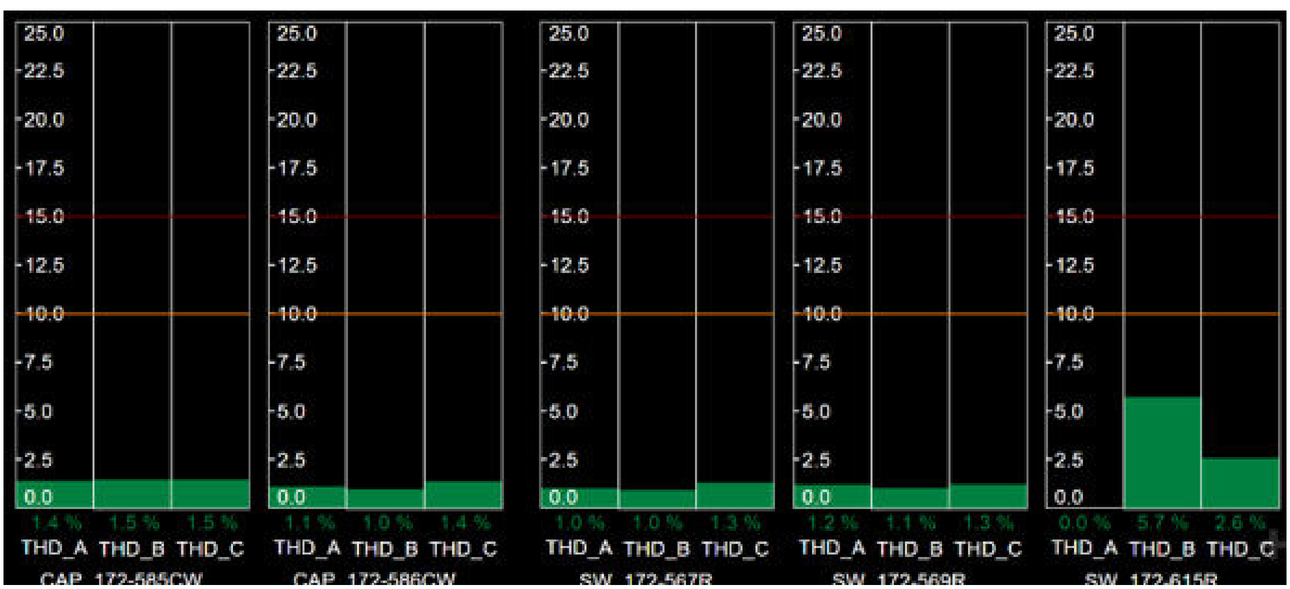


Figure 3-3. THD measured at various locations of selected circuits (all three phase); source: SCADA

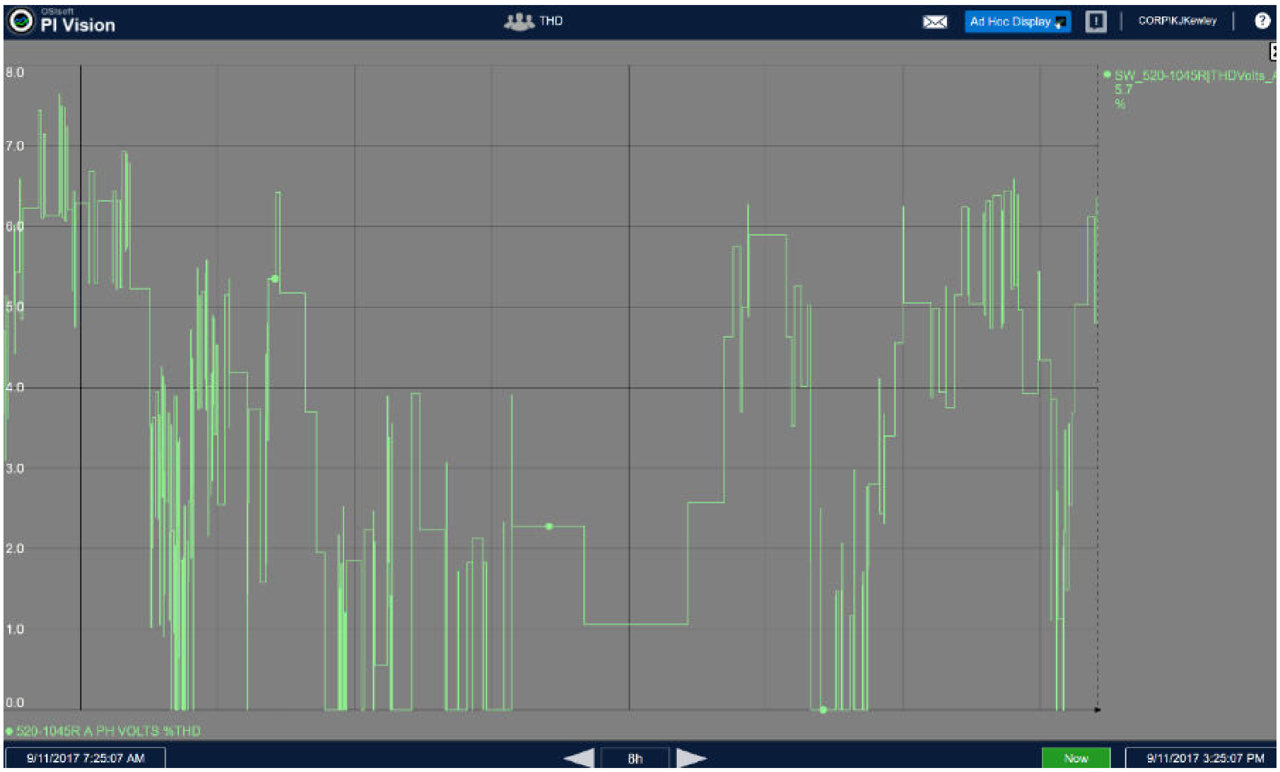


Figure 3-4. Harmonic distortion (time frame) at one of the switches on circuit 1 (obtained from SCADA)

The following screen shows voltage difference from nominal value (in pu) measured at each PMU location on circuit 1. The upper and lower bars are +/-5% target levels from the nominal voltage (on 12 kV basis).

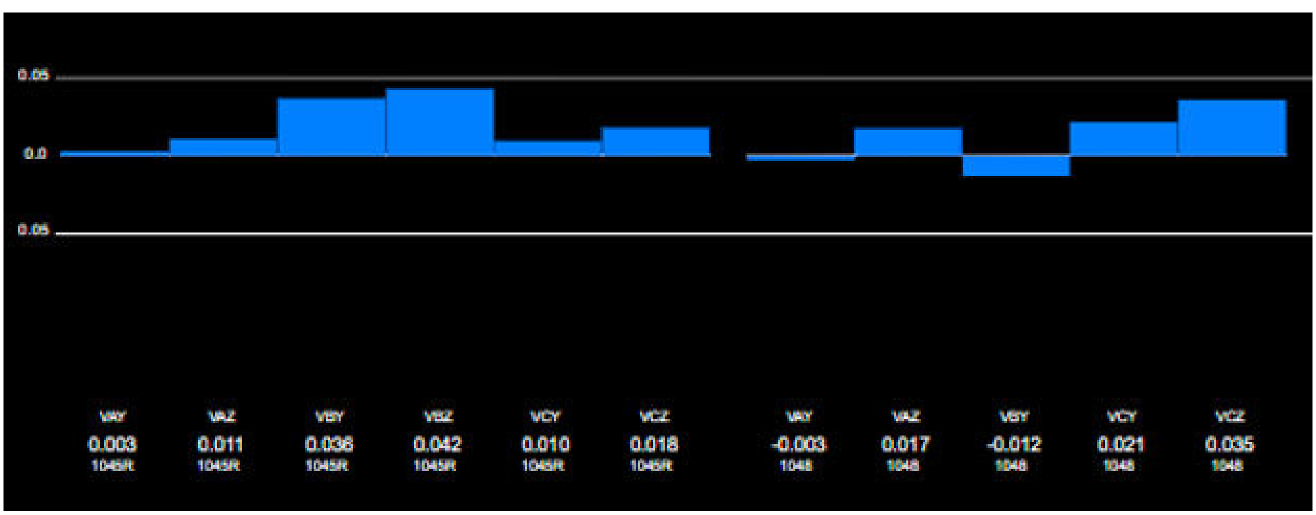


Figure 3-5: Voltage difference (in pu) on Circuit 1

The following screen shows active and reactive power by device as a bar chart. Active and reactive power are calculated for each existing phasor in real-time based on the data from OpenPDC and fed into the PI system. By using PI Vision for this visualization, the user can select any data and time to view the historical active/reactive power data on the devices. Negative values represent areas that reverse power flow occurs on the circuit.

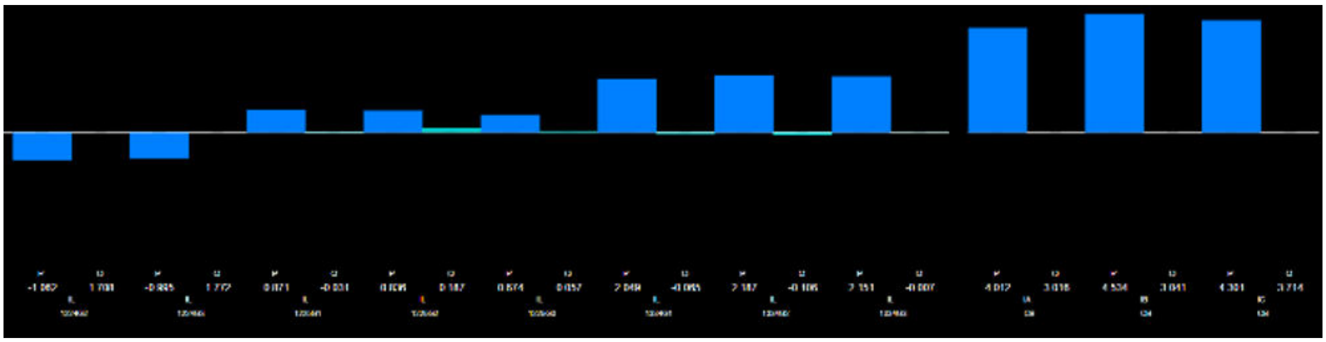


Figure 3-6. Active and reactive power flow for Circuit 1

The following two screen shots show thermal loading plots for Circuit 1, 2, and 3. The bars will change colors when they reach the rating limit lines, defined by a look up table for each feeder device and section of the line.

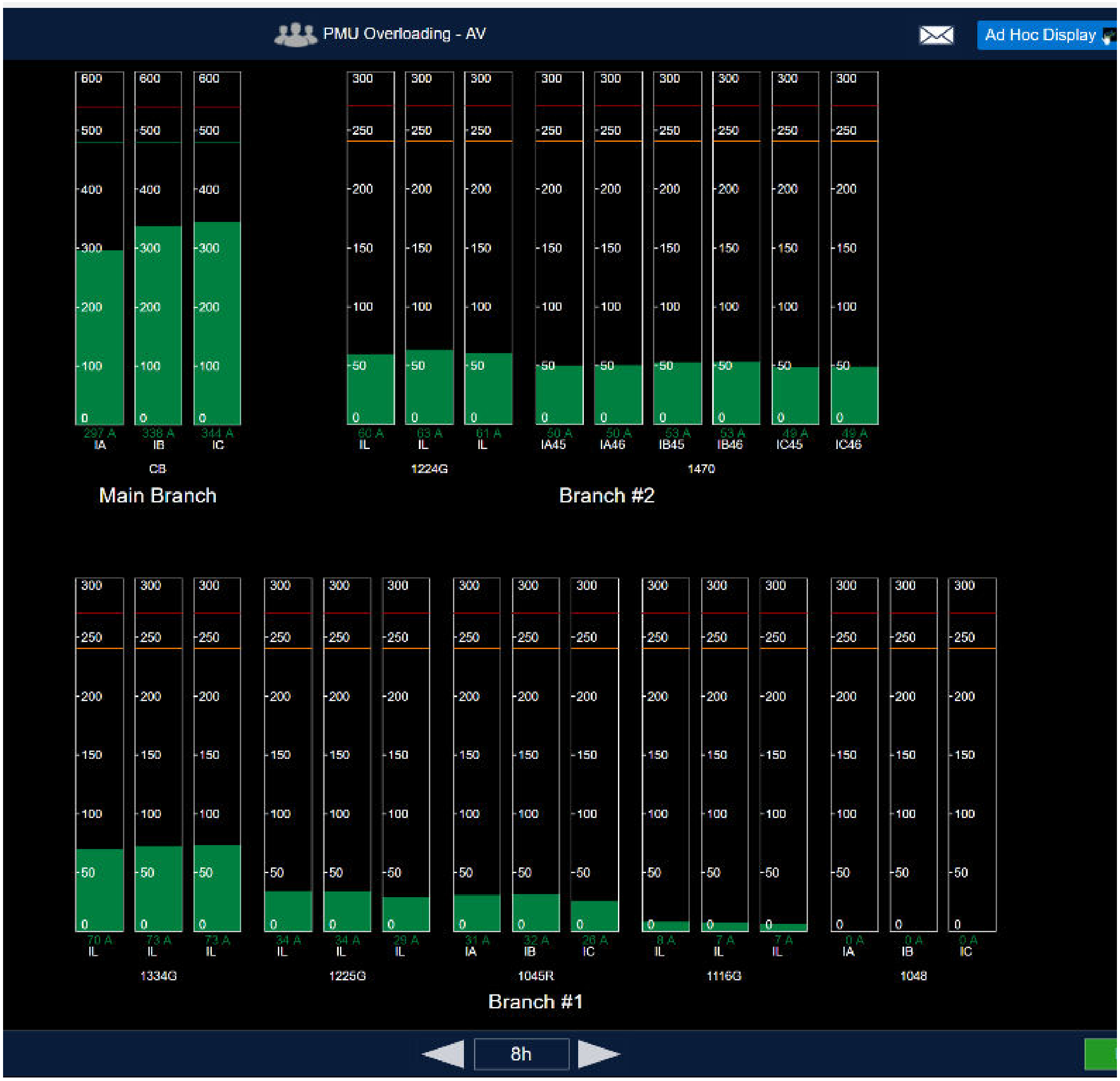


Figure 3-7. Thermal loading asset monitoring on Main branch, Branch #1 and Branch #2 of the Circuit 1

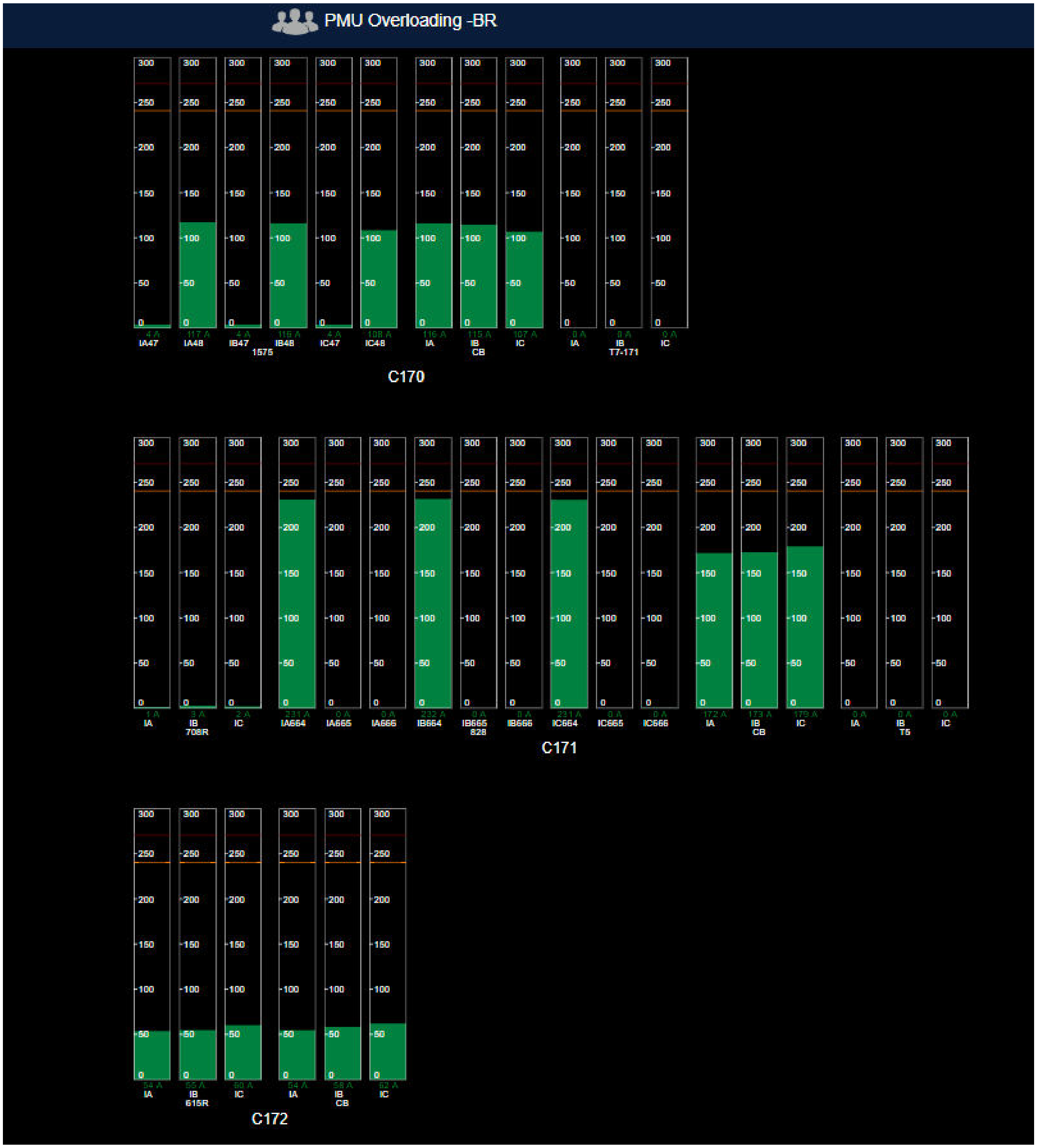


Figure 3-8. Thermal loading asset monitoring for Circuits 2, 3 and 4

The following is a screenshot from the Active/Reactive power values on Circuit 1. It can be seen that some of the PMUs with high MVAR values have bars that are displayed in red so they stand out in a large list.

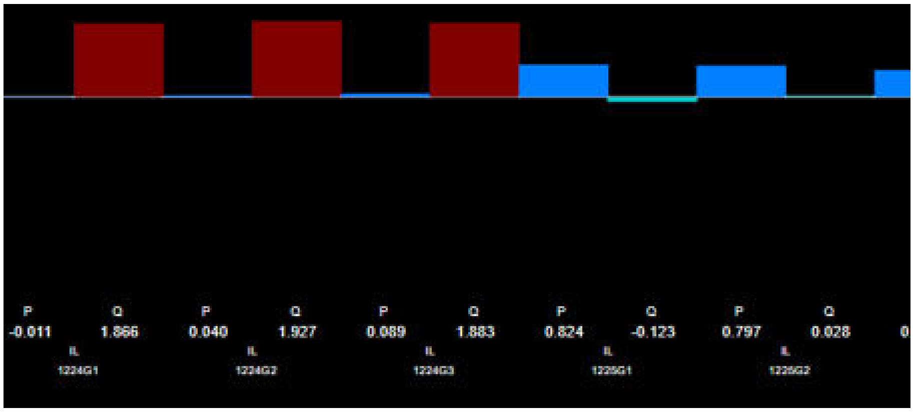


Figure 3-9. Active/Reactive power along Circuit 1

Figure 3-10 is the screenshot for reporting and visualizing the overloading conditions. The limit lines are accurately calculated for circuit breakers. The limits for the field devices are not determined because there are many factors down the line that effect the rating. The feature uses a look up table for field data update.

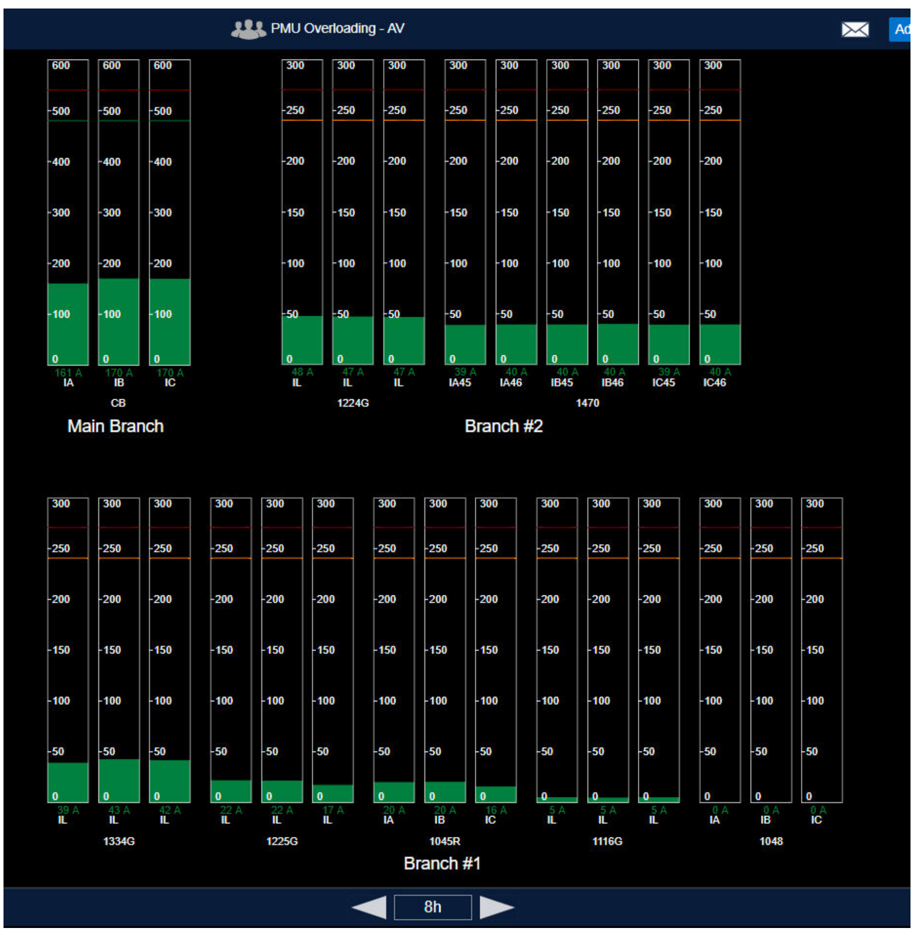


Figure 3-10. Overloading bar chart display for Circuit 1 based on PMU data

The following screenshot provides the tabular reporting format of the circuit level device loading. The report is organized by the main branch (backbone) and each individual branches (laterals). In the advanced visualization the aim is to move from tabular data to graphics and summary reports that can fuse multiple measures into specific metrics to support fast-decision making by operators.

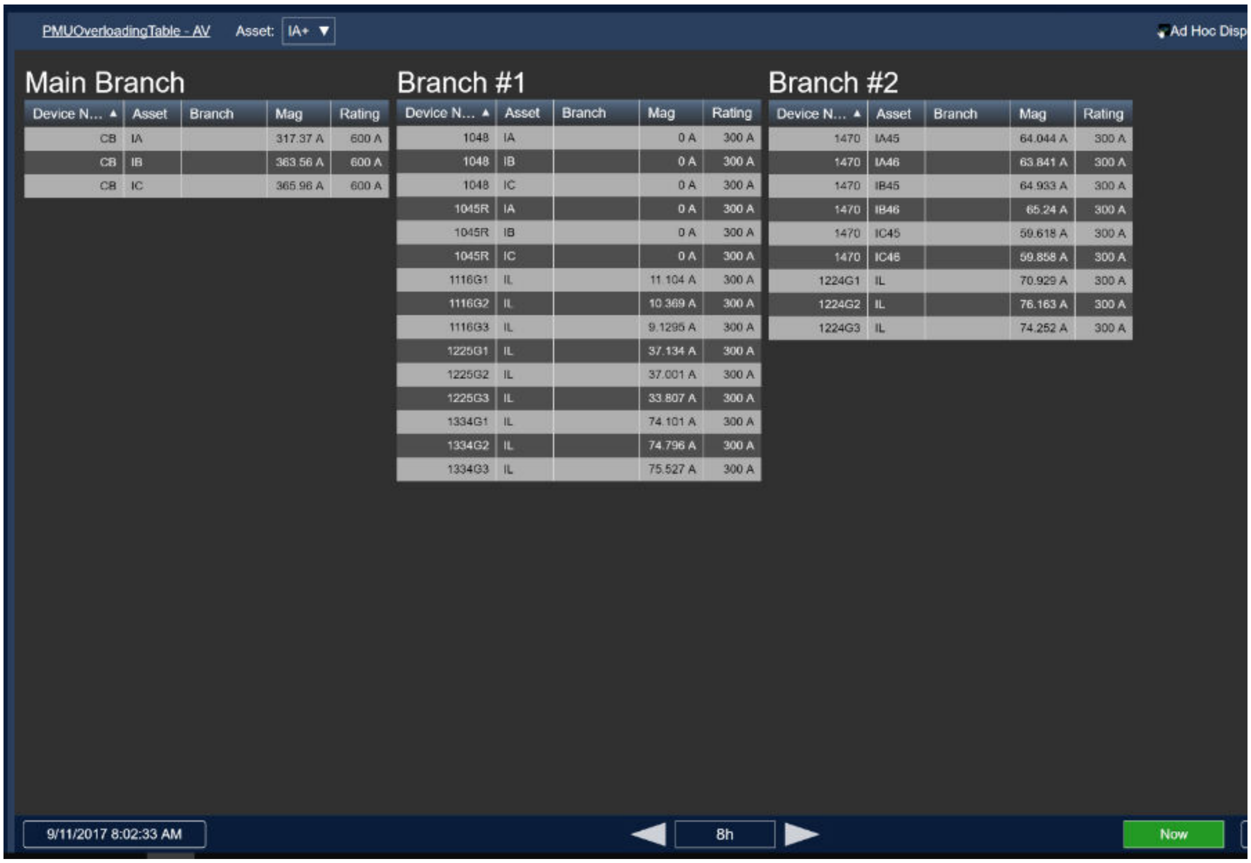


Figure 3-11. Tabular reporting of device loadings for Circuit 1 based on PMU data

The following display shows another PIVision display with voltage along the feeder. This display gives the operator a clear view of voltages over the entire circuit. The limit lines and color changing bars draw attention to large voltage deviations.

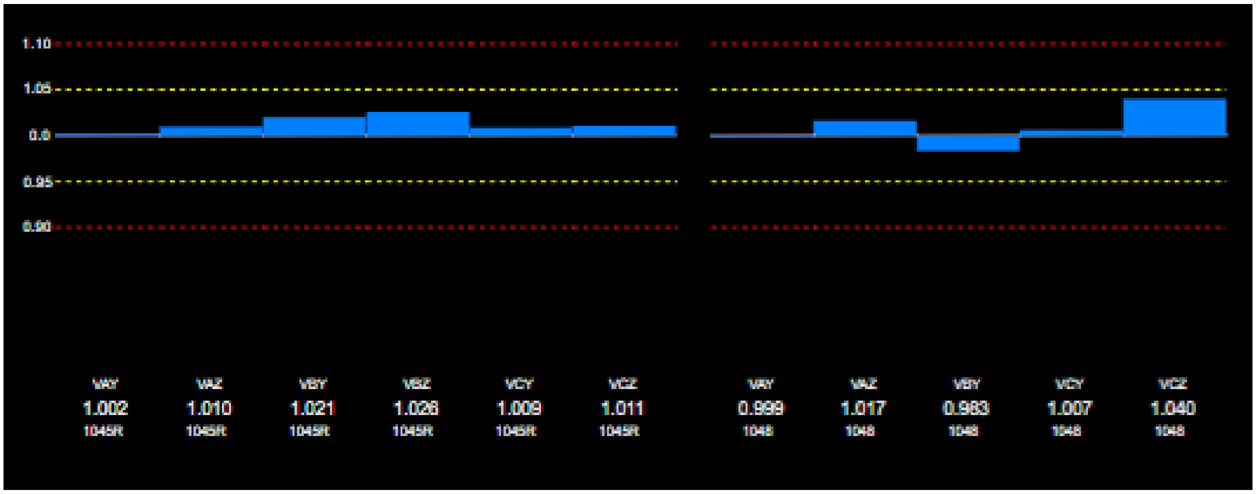


Figure 3-12. Voltage deviations (from base voltage) in percentage along the selected circuit length (circuit 1)

3.2 Real-time measurement examples

One of the menu selection options on the visualization screen navigates to real–time PMU visualization software platform. In this subsection, several real-time screens (based on the visualization requirements) obtained from field PDC are shown to demonstrate the built in capabilities and type of data visualization available.

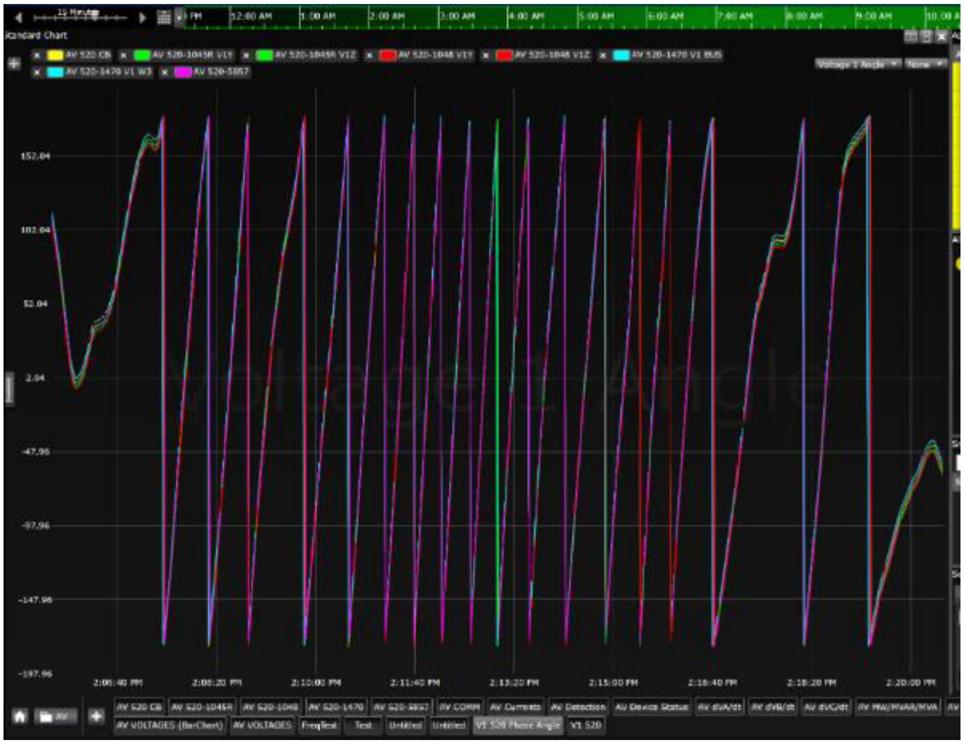


Figure 3-13. Voltage phase angle in phasor time domain

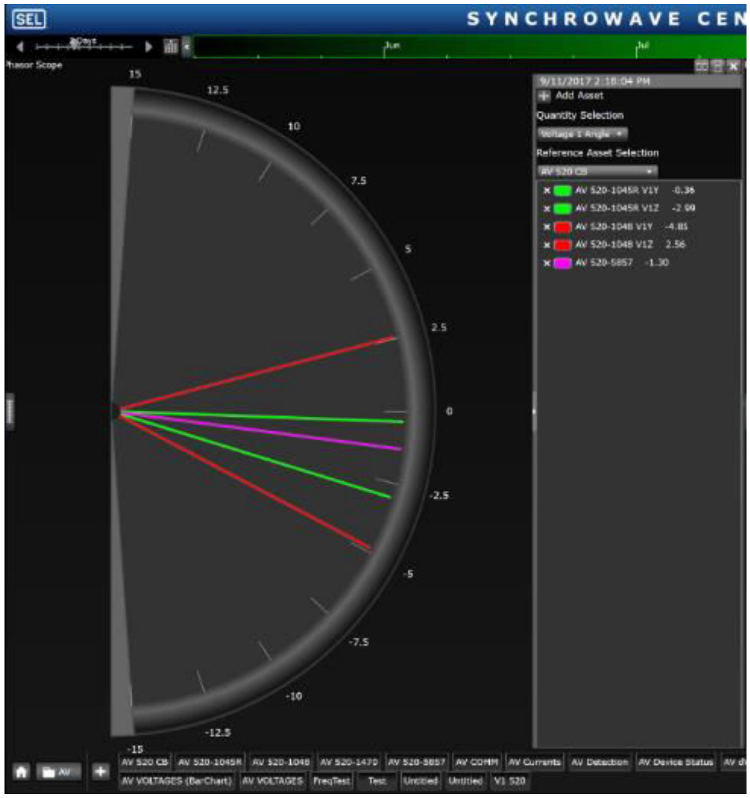


Figure 3-14. Polar version of real time monitoring of voltage phase angles

The following displays show voltage magnitude and phase angle for the device 520-1470 (near the large 2MW solar site toward the end of circuit 1). The displays are built out for several circuit breakers and recloser on the line, such as: 1045R, 1048, 1470, and 5857.

Figure 3-15. Voltage magnitude of the Circuit 1 PMUs (standard view)

Figure 3-16. Voltage phase angle of the Circuit 1 PMUs (standard view)

The following display shows active, reactive, apparent power for the circuit breaker, and PMU 5857 which is located just outside of the 2MW solar PV site.

Figure 3-17. Numeric display for selected PMUs

3.3 Visualization displays on the GIS map

In addition to the aforementioned screens, some of the visualization requirements were based on the GIS maps to show the distributed and geographical nature of the distribution circuits. Examples of GIS map based screens and built in functionalities are shown in this section.

The next two figures demonstrate visualization of real-time measurements for total active power generation units in the PV plant, and customer loads, respectively. The data is also obtained from the field and the blue circles show geographical measurements locations. The active power data displayed for PV Customer generation is the nameplate rating of the PV system rather than real-time. All of the other data on the map is real-time PMU data.

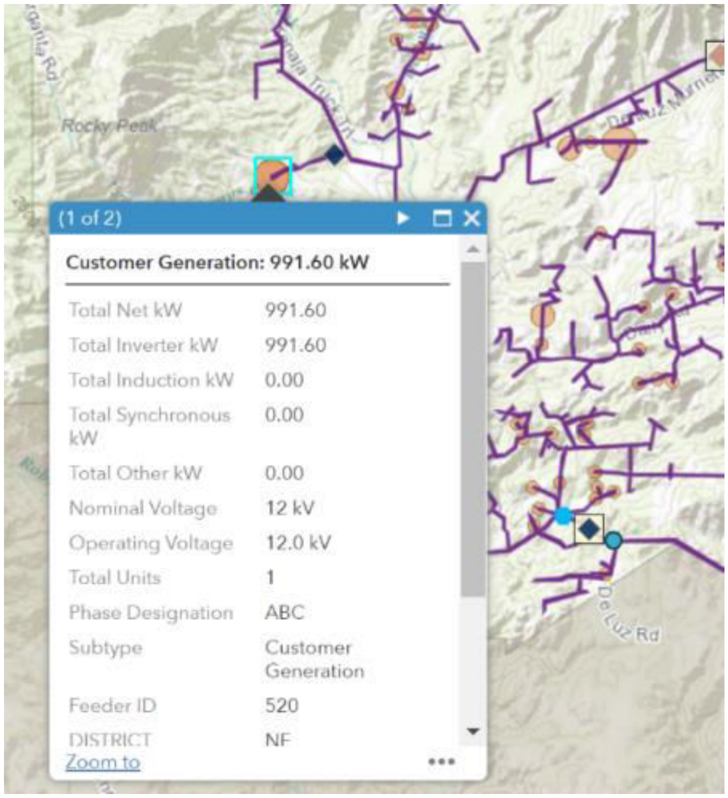


Figure 3-18. Total active power generated by PVs

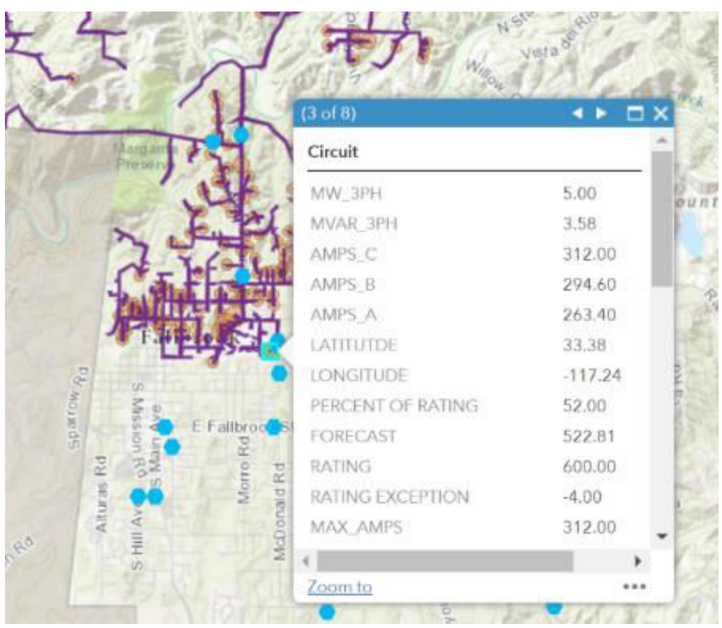


Figure 3-19. Real time monitoring of customer loads

The next two figures show real-time measurements of voltage regulator tap positions and capacitors status, respectively. The screenshots show capacitor switching on the cap information popup and the time series display of that value. The values are incremented whenever a capacitor switches on or off. The status changes can be because of time bias or changes in the voltage level of the circuit. PV production fluctuation is also a key contributing factor. The number of tap changes need to be monitored.

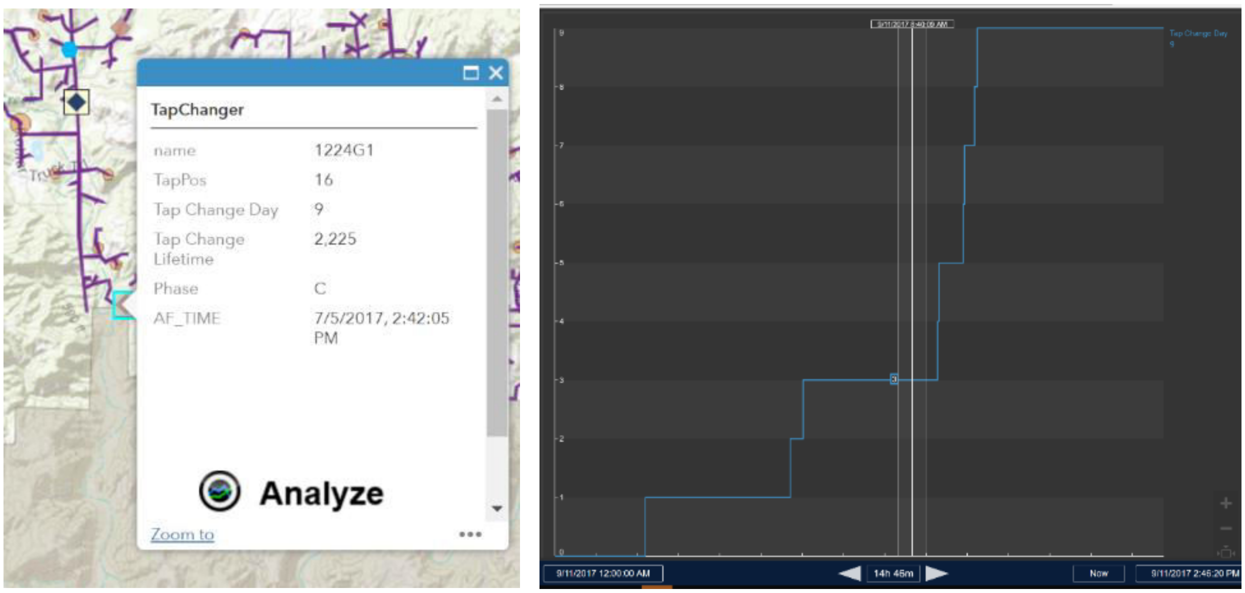


Figure 3-20. Monitoring of Tap changer status (left) and tap positions change over time (right)

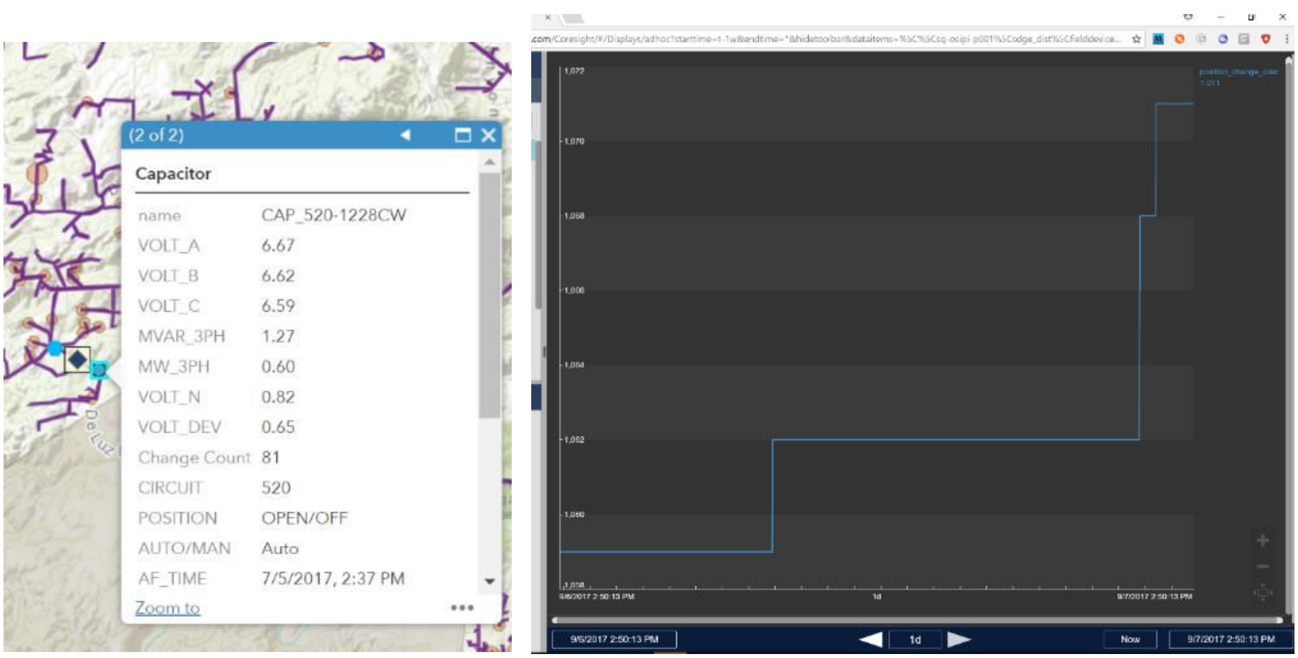


Figure 3-21. Real-time monitoring of cap banks status

Voltage Sag and Swell are some of the KPIs that need to be monitored and visualized as described in the system requirements. Figure below illustrates one of the implementation cases for these requirements.

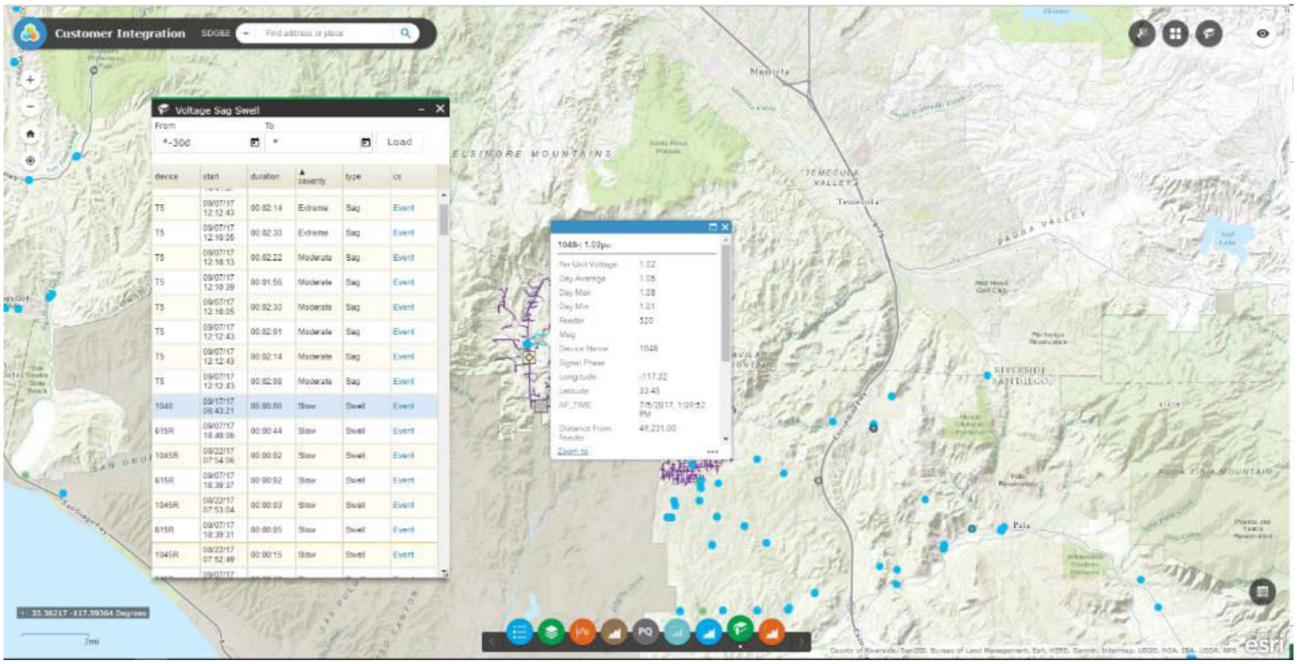


Figure 3-22. Demonstration of KPI monitoring

By clicking on an event on the table, it selects the matching attribute in the map. By clicking on the "Event" link, it brings up a PI Vision display showing the per unit voltage with limit lines for the time range of the event.

To create this display, the processing engine behind it has to detect the events using a custom extension on the OpenECA platform written in C#. OpenECA provides the custom program with synchronized real-time synchrophasor data. The program is configurable, so it can specify different thresholds for different sag/swell severities. Each severity has a set time duration and percent exceedance that must be reached for the event to be counted. Once an event is detected, an event frame is created in PI and linked to the correct device and phase. When the event concludes, the end time is updated in PI as well.

Once the data captured in PI, the processing engine uses a custom widget used to display the data in our web app. The user specifies a start/end for the search and clicks load. The widget makes a request to a custom web service that uses the PI macros to load and return the relevant event frames.

The following screens show the "interconnection violation" indicators for voltage sags, voltage swells, and power frequency. The ride-through thresholds and durations are determined from CA Rule 21 requirements.

The bar charts at the bottom count total number of voltage sags/swells for the current date. The threshold lines (blue and yellow lines) are calculated using the 30 sample per second OpenECA data and fed into PI. When the voltage reaches a configured threshold, the threshold line immediately jumps to the next threshold for a specified amount of time. To not violate the Rule 21 specifications, the voltage should recover within that time limit.

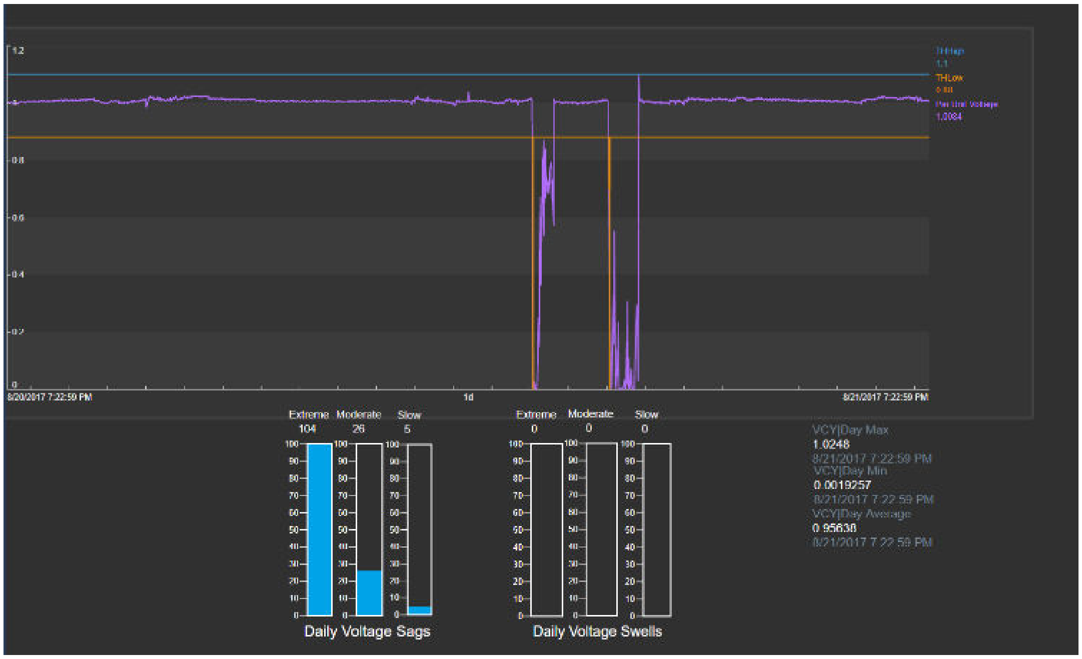


Figure 3-23. Sample of the captured voltage sag versus the acceptable thresholds and durations

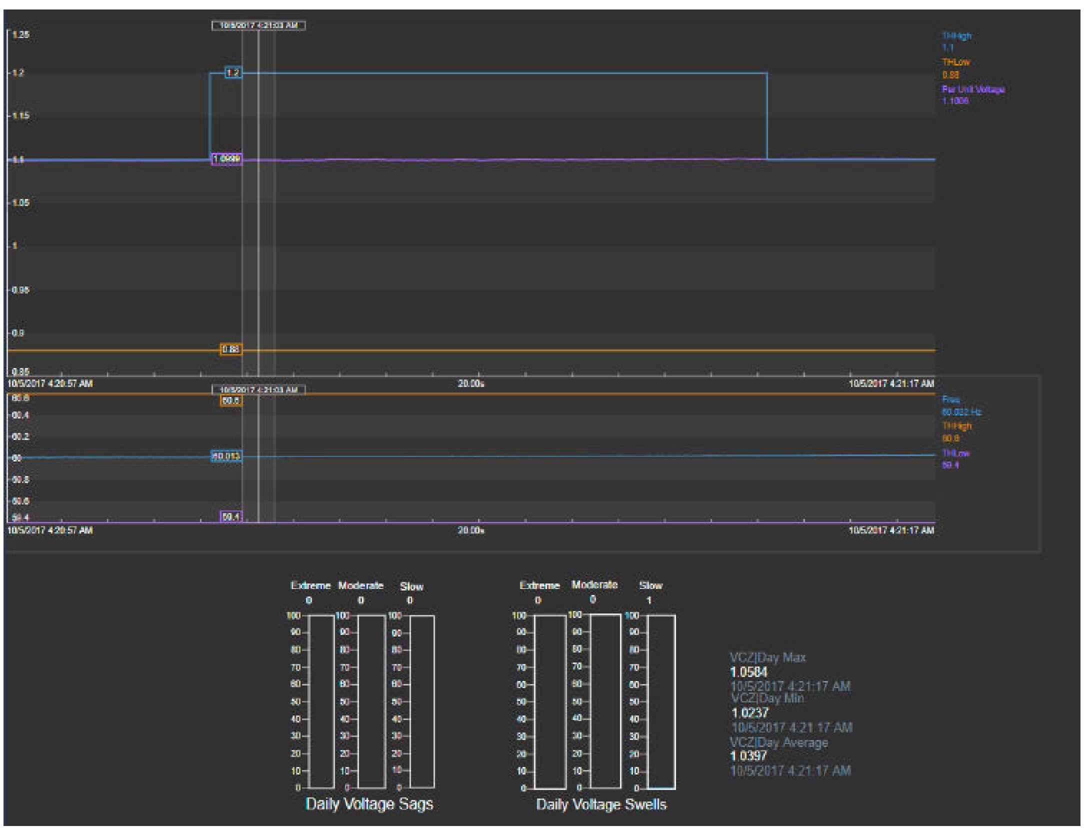


Figure 3-24. Sample of captured voltage swell versus

The voltage sag cases reported in the previous plots were caused by a sensor measurement problem on a line recloser. The voltage drops were only became observable when the PMU data streaming and visualization put in place.

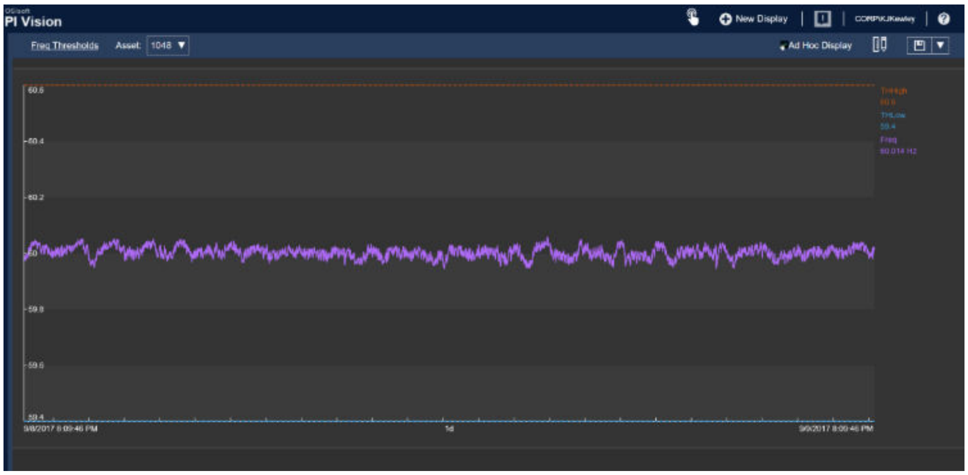


Figure 3-25. Frequency violation monitoring

Above screenshot uses similar calculations, but the thresholds are configured for frequency data. In this case, the high threshold is 60.6Hz and the low is 59.4Hz. Generally, frequency in distribution system is more stable and there should not be any violation of these thresholds on the circuits. However, if a cascading fault and outage event on transmission system causes a sudden frequency change and restoration, the distribution PMUs should be able to detect that.

The following screen calculates the voltage sensitivity of the PMUs. This PI process book screen is linked to the map. The values on the XY plot come from a calculation done in OpenECA. When there is a large change in voltage, the calculation returns $\frac{\Delta V}{\Delta P}$ and $\frac{\Delta V}{\Delta Q}$. This is plotted on a chart with the y axis as the calculated value and the x axis as the per unit voltage. On the left hand side, different PMU locations can be selected for display.

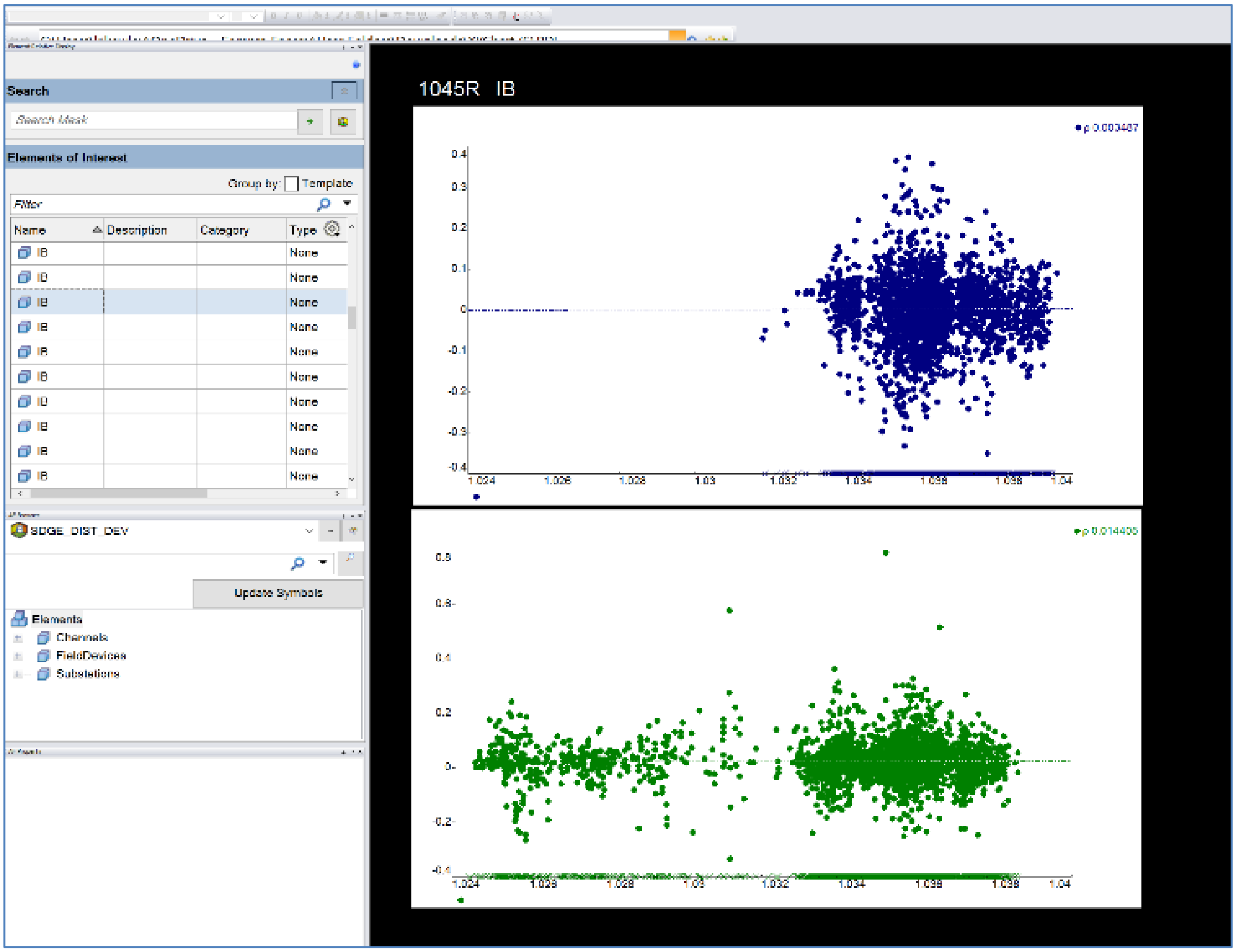


Figure 3-26. Power sensitivity trending for Circuit 1

The next figure shows the min/average/max voltage profiling plot for the entire circuit. Small horizontal line shows the average voltage, and the two ends of the long vertical line show minimum and maximum voltages in a day.

This visualization was created with a custom widget in Web AppBuilder. When opened, the widget subscribes to feature selection on the map. When a feature from the layer specified in the configuration is selected, the widget gets the "feeder" attribute of the selected feature. Then it makes a request for all the min, max, average, distance, and name attributes of features with the same feeder ID. Once the data is returned, the candlestick chart is drawn using the "dojo" framework charting library.

The plots was considered very beneficial for engineering analysis purpose and operator troubleshooting. In one glance, the engineer or the operator can determine the worst case locations on the circuit and narrow down the focus on analyzing those locations.

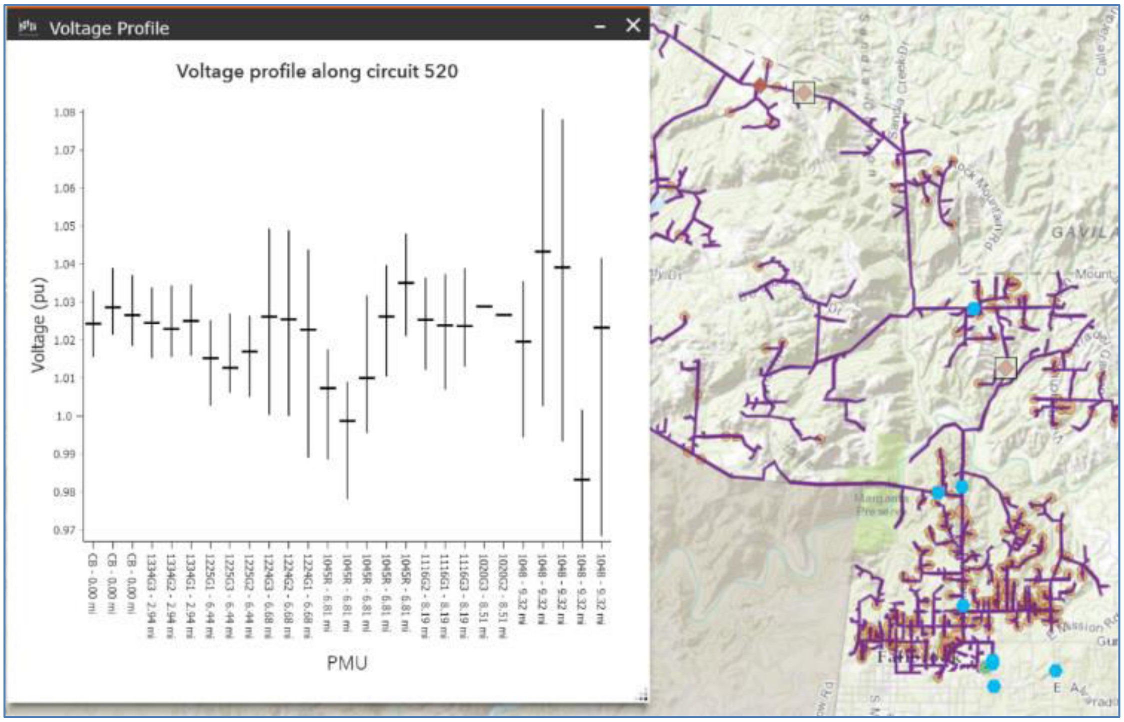


Figure 3-27. Voltage monitoring demonstration – Use Case 1

3.4 Power quality monitoring examples

Figures below illustrate visualization of odd/even harmonics and total harmonic distortion for selected substations. The detail harmonic information was extracted from PQview data base and incorporated in the visualization screen of this project. During the course of the project, it was noted that several SDG&E distribution substations are already equipped with power quality meters. The harmonic data are captured for pre-defined disturbance conditions (such as sudden voltage changes beyond 20%, or RHD greater than 3%) in PQdiff format. The PQview database collects and organize the PQdiff event records which will be the source of extracting harmonic information.

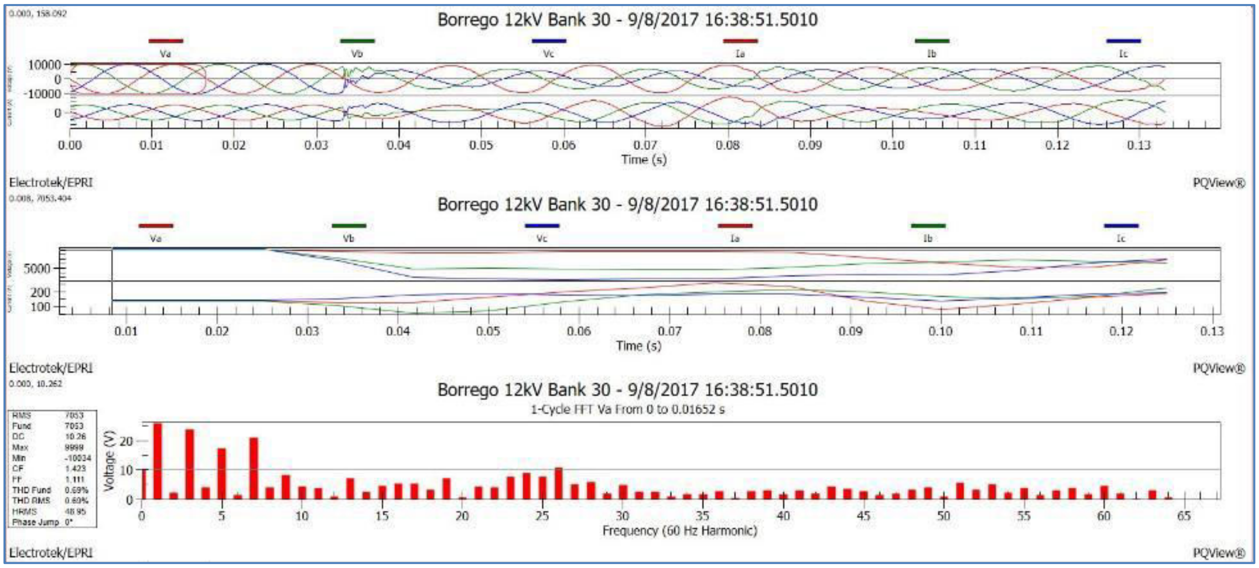


Figure 3-28. Monitoring of odd/even harmonics

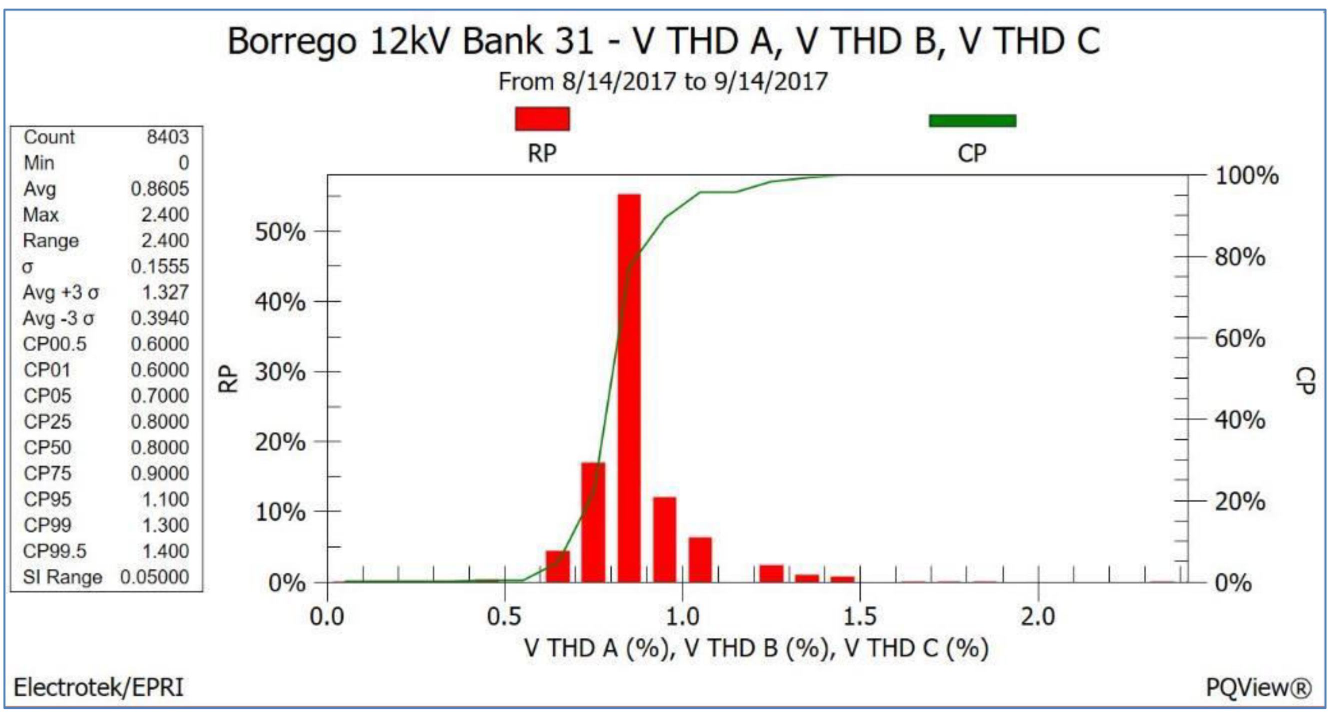


Figure 3-29. Visualization of total harmonic distortion (THD) on one of the selected circuits

3.5 Key performance indices monitoring

Figure below shows the data captured form one of the PQ meters at a distribution substation. The PQ meter provided a measurement of long term flicker factor as an example of the proposed performance indices. In order to calculate flicker factor, the number of voltage dips per minute has to be monitored and counted over the long moving window. However, the substation PQ devices already have internal calculation capability of the flicker factor. The feature was integrated in the visualization screen.

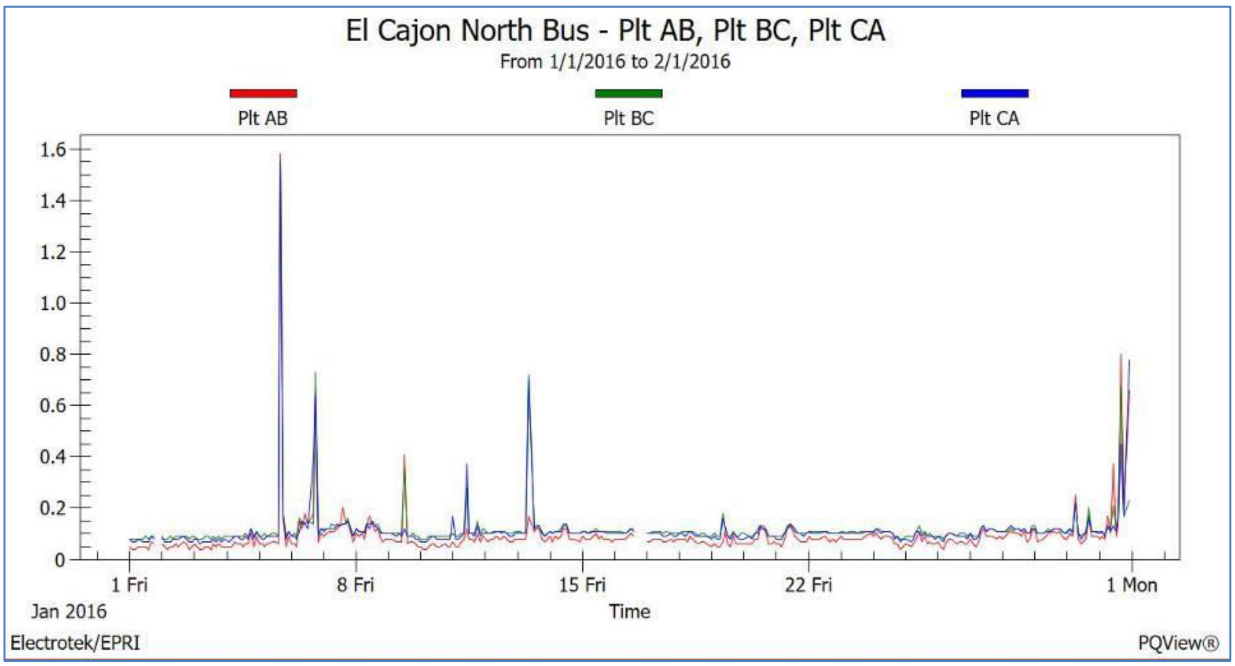


Figure 3-30. Illustration of Flicker factor monitoring and visualization

4 Pre-Commercial Demonstration Results based on Laboratory Setup

In this section, the results of the test cases for selected circuits (Circuit 1, Circuit 2, Circuit 3, and Circuit 4) based on different use cases demonstrated in the ITF laboratory are provided.

4.1 Circuit 1 Test Results

A simplified single line diagram of the Circuit 1 and the test setup are shown in Figure 4-1. The single line diagram is an overall representation of the model built in the RTDS environment for the laboratory testing and evaluations.

As indicated in this figure, there is a 2 MW PV system at the end of the circuit. The circuit backbone branches out in two directions. There is a normally open tie switch (520-1048) between the two branches of this circuit. For load transfer cases, the tie switch can be closed and one of the upstream reclosers can be opened to change the load flow and voltage profile of the circuit. Six voltage regulators and two switched shunt capacitors are installed on this circuit. A Dynamic Voltage Regulator (DVR) is also installed on the branch to the PV site, upstream of the PV location. DVR is used to mitigate significant voltage issues due to high PV production and loading condition. For the purpose of this study, this circuit has been modeled in RSCAD[1]. 12 PMUs including 8 simulated PMUs (PMU1 to PMU8) and 4 physical PMUs (PMU9 to PMU12) are located at various nodes in the study system to facilitate system monitoring during the tests.

[1] All controllable assets (voltage regulators, load tap changers, and capacitor banks) are also modeled in details in the real-time digital simulator (RTDS) to enable integrated voltage/var control in the distribution circuit under study.

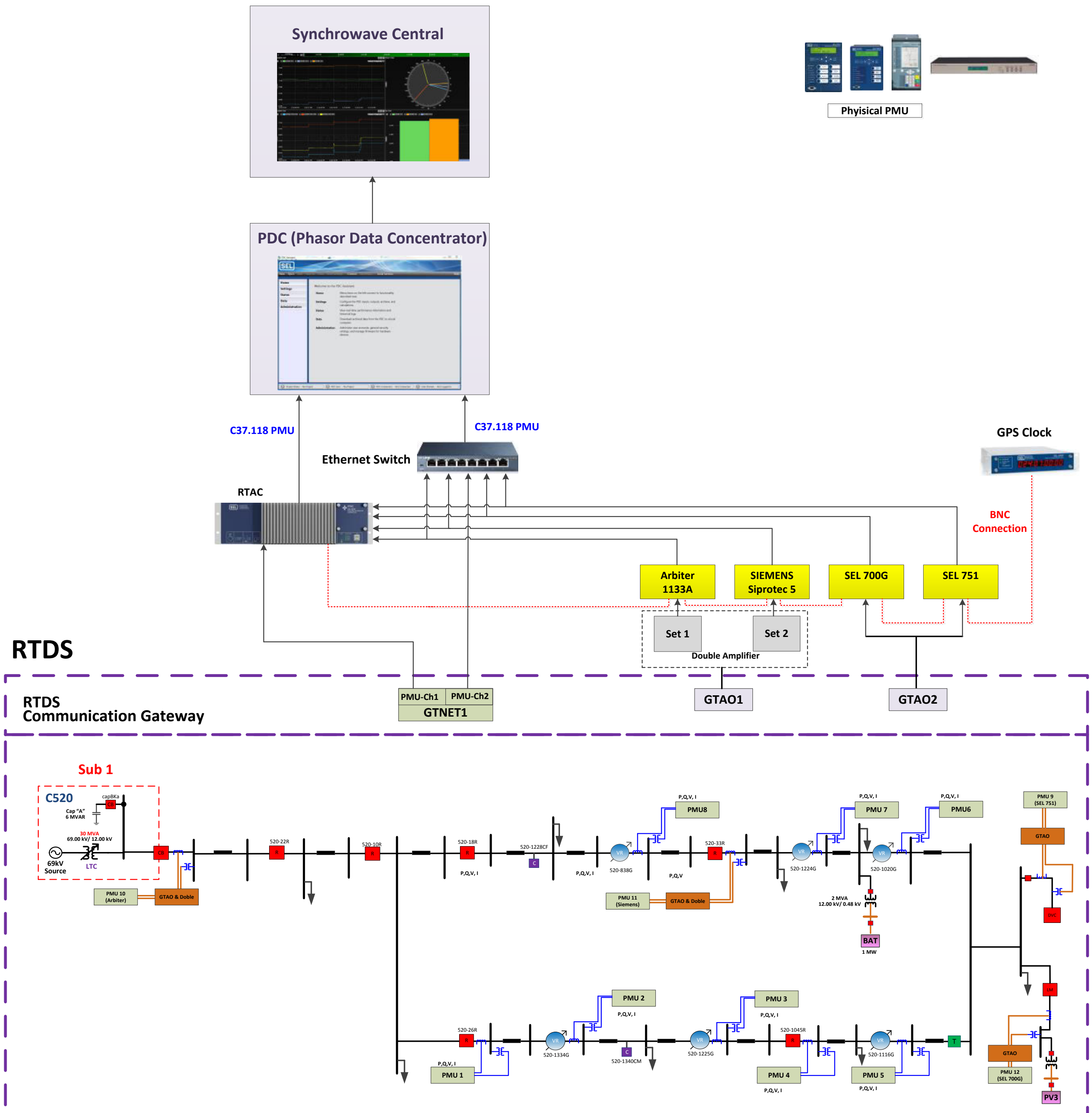


Figure 4-1. Single Line Diagram and PMU Locations of the Circuit 1

The PMUs data (either obtained from the real-time digital simulator or actual physical hardware) is streamed to PDC and RTAC. Simultaneously, RTAC processes the input PMU data and sends the calculated parameters into the PDC. Finally, all data obtained from PMUs and RTAC will be time aligned and sent to SynchroWAVe for monitoring and visualization purposes. The calculated values in RTAC are as follows:

- Delta V in per unit (with respect to the base voltage of 12 kV)
- Unbalance factor in % (using V2/V1 – negative to positive sequence voltage ratio)
- Extreme voltage sag count (V<0.2 pu for 10 cycles)
- Moderate voltage swell count (0.2 <V< 0.4 pu for one second)
- Extreme voltage swell count (V > 1.3 pu for 10 cycles)
- Moderate voltage swell count (1.2< V < 1.3 pu for 1 second)
- Alpha factor (dV/dP) in pu/MW
- Beta factor (dV/dQ) in pu/Mvar
- Flicker index (calculated based on the number of voltage dips per minute)

In addition to these calculations, THD and tap positions are directly sent to the PDC using the analog values of the simulated PMUs.

In the following section, different case studies are investigated and reported for the validation of the test set-up and the calculations in the Avocado circuit.

4.1.1 Voltage/Power Flow Monitoring

The purpose of this test category is to verify proper communications amongst various components of the test setup and to demonstrate the built-in visualization capability of the SynchroWAVe Central. Furthermore, it will evaluate the calculation of Delta V (per unit) in RTAC.

4.1.2 Long-term Monitoring

In this test, the winter load profile was run for 90 minutes with PV and the following measurements were captured from SynchroWAVe Central for all PMUs.

- Magnitude of positive sequence voltage
- Magnitude of positive sequence current
- Phase angle of positive sequence voltage
- Phase angle of positive sequence current
- Active power
- Reactive power
- Apparent power
- Delta V (per unit).

Figure 4-2. Magnitude of Positive Sequence Voltages

The fluctuations in the voltages and currents are caused by the changes in the load profile, PV profile, and tap position changes of the voltage regulators. The changes in load and generations are observable from a visualization graph such as the one shown below for capturing positive sequence currents at PMU locations.

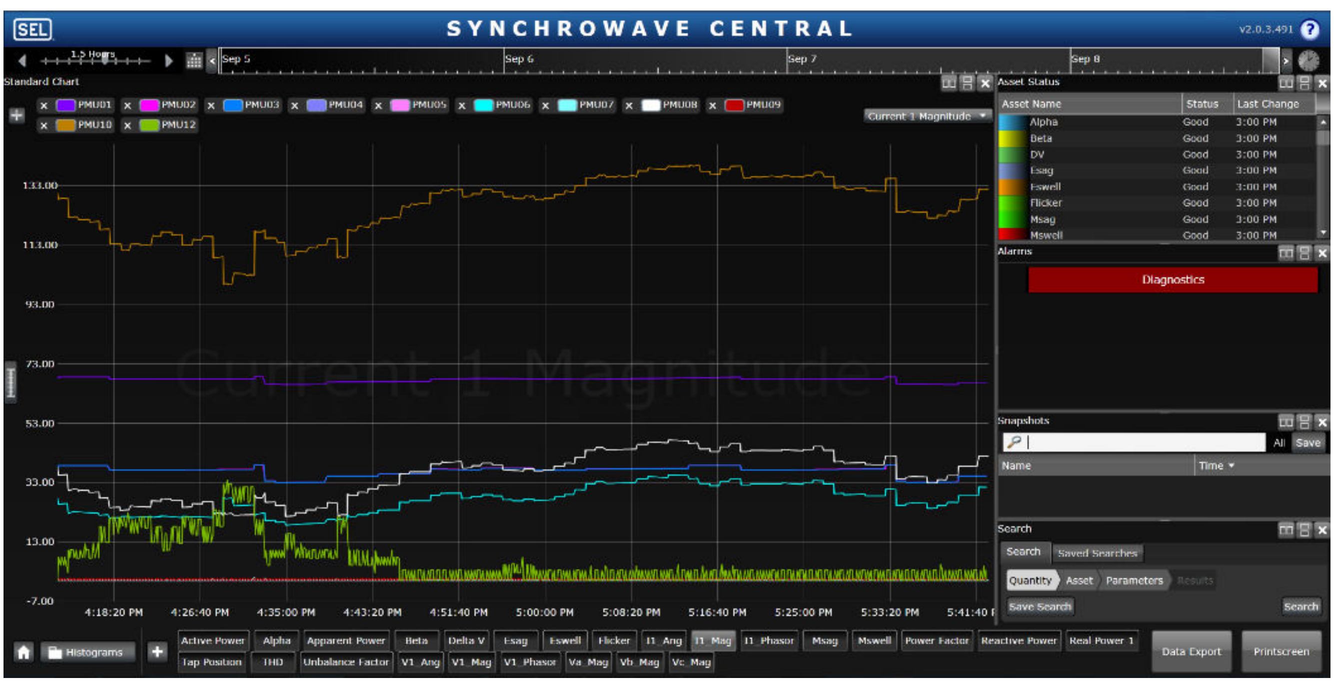


Figure 4-3. Magnitude of Positive Sequence Currents

Other visualization screens were used to capture phase angles of the voltage and current phasors as shown below. Phase angle visualization were primarily used during synchronization and load transfer schemes. Sudden changes in load or issues associated with customer introduced disturbances can also be identified from phase angle measurements by noticing any sudden jumps (typically called vector jump).

Figure 4-4. Phase Angles of Positive Sequence Voltages

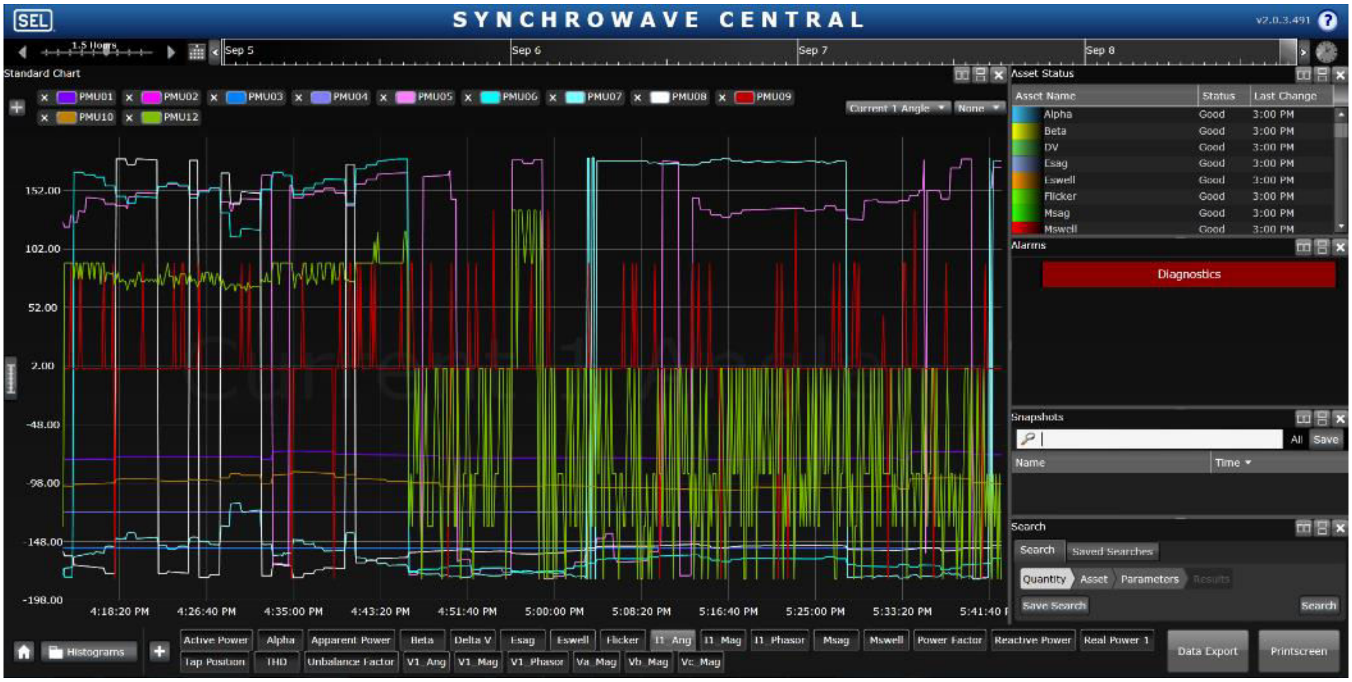


Figure 4-5. Phase Angles of Positive Sequence Currents

The reason for the current phase angles fluctuations in PMU 09 and PMU 12 is that the currents of the aforementioned PMUs are zero; therefore, the PMUs cannot correctly calculate phase angles from noises.

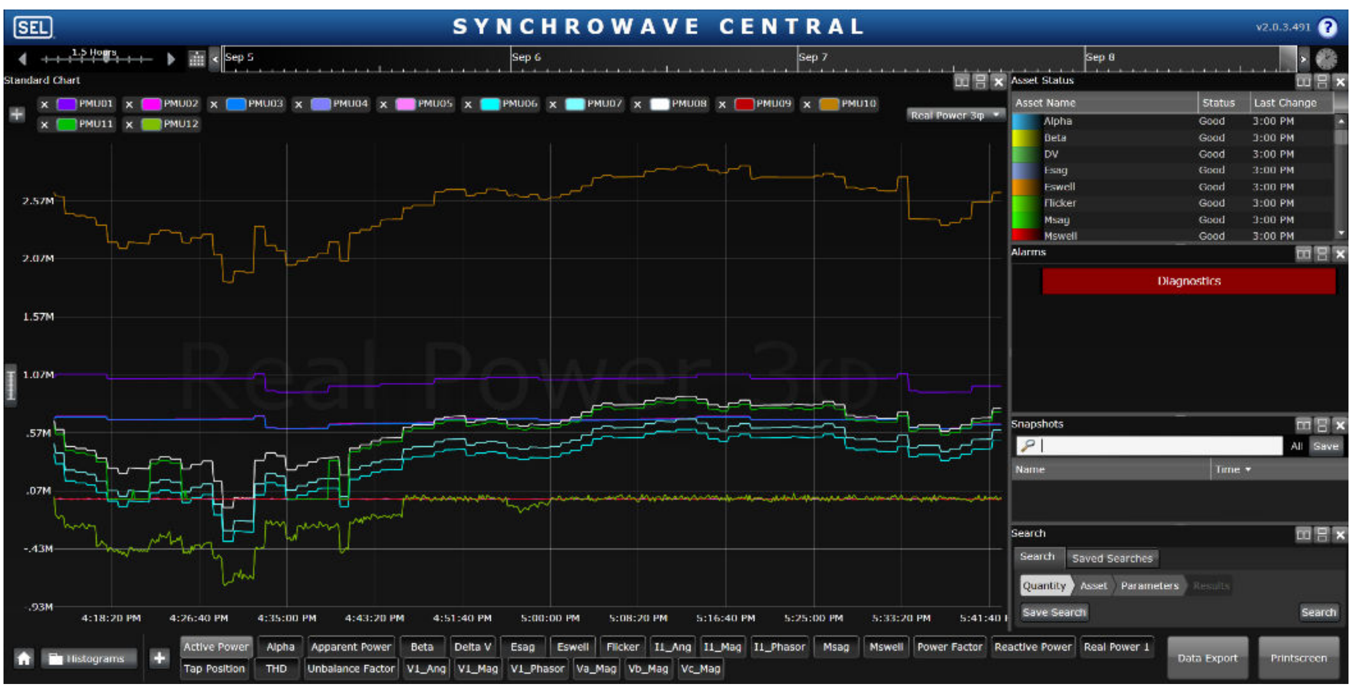


Figure 4-6. Active Powers

Active and reactive power visualization screens were used to investigate power flow across the circuits.

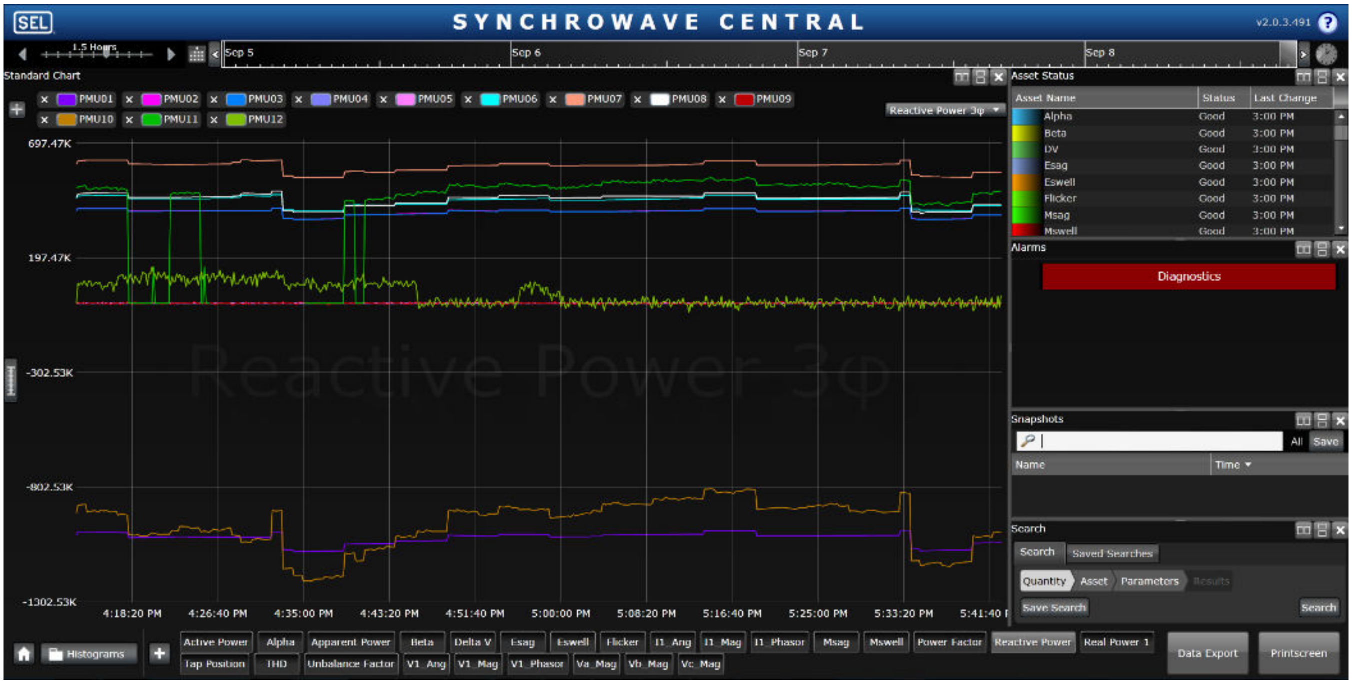


Figure 4-7. Reactive Powers

The apparent power screen was used to evaluate the thermal rating of the circuit and feeder devices.

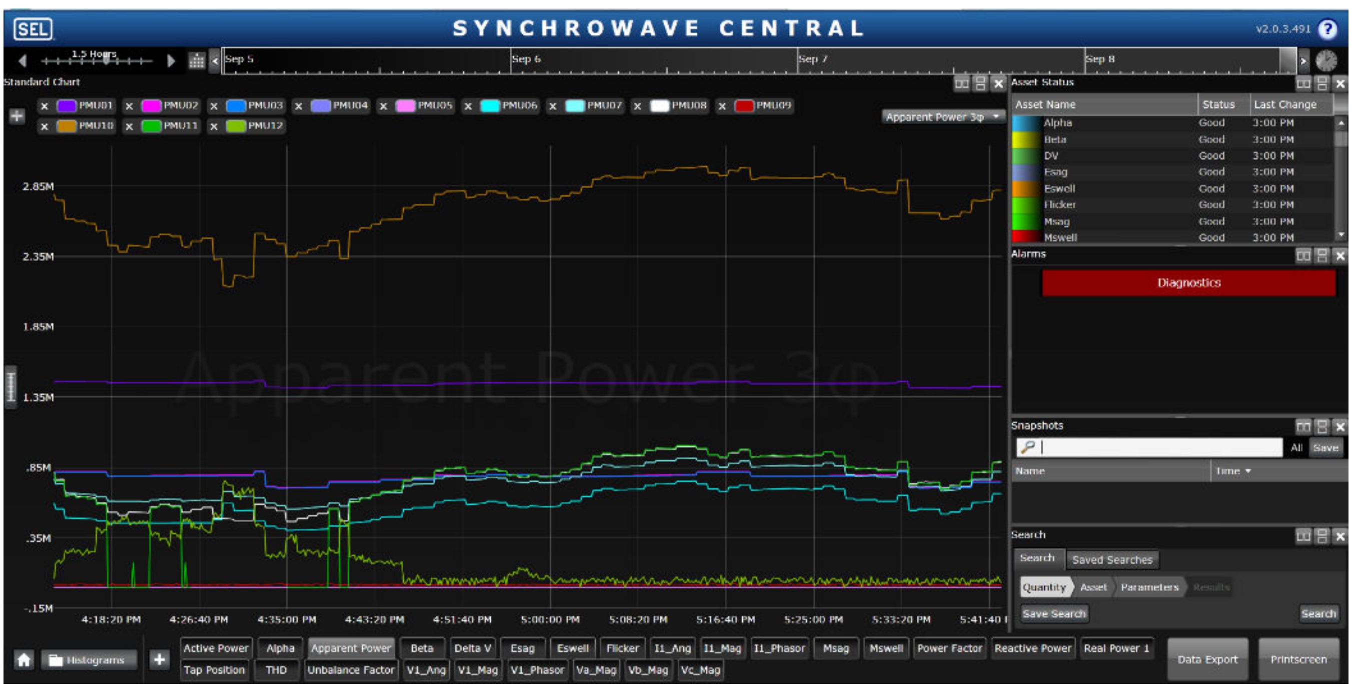


Figure 4-8. Apparent Powers

Figure 4-9. Calculated Delta V (pu) in Automation Controller

From the above graph, it can be simply observed that the voltage differences (compared to the nominal voltage) across the circuit do not violate 0.05 pu.

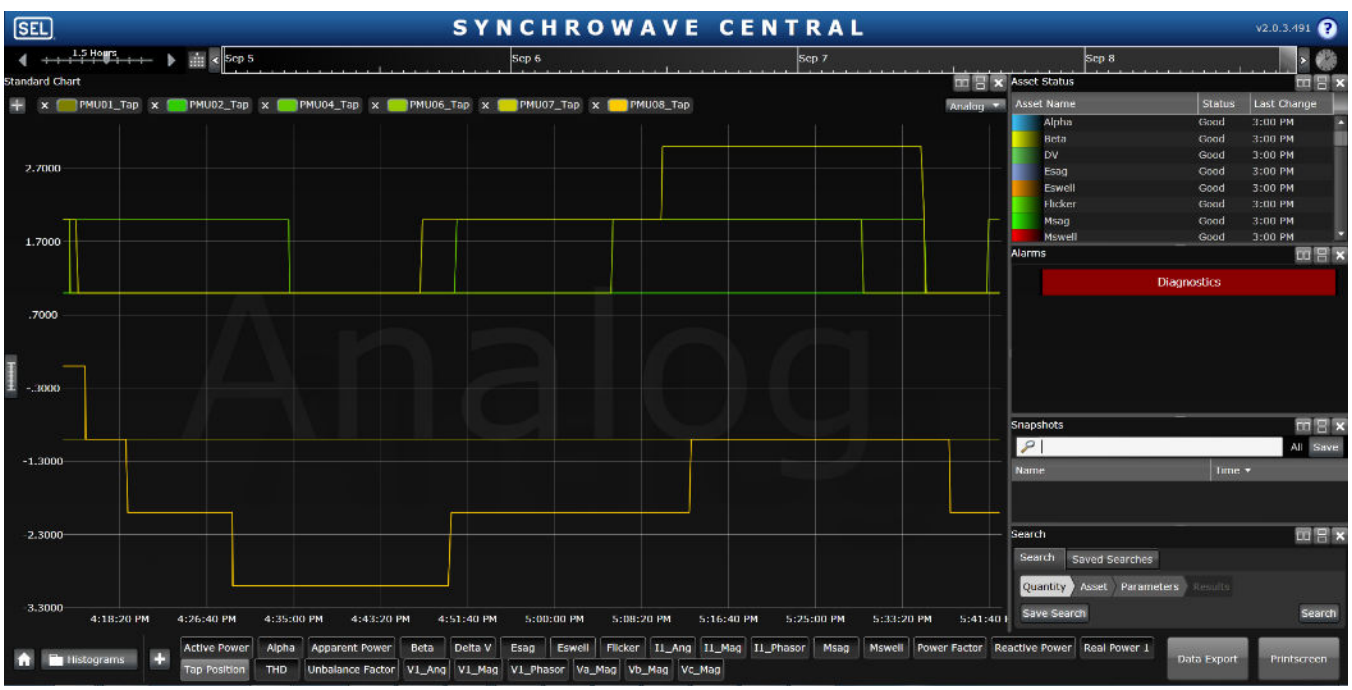


Figure 4-10. Tap positions streamed through the analog value

4.1.2.1 Phasor Monitoring

In this test, the behavior of the circuit 1 was studied during a load transfer.

Initially, the circuit was set at constant low load condition (0.3 pu) with no PV. Figure 4-11 shows the active powers before the connection of the PV. It can be observed that there is no reverse power flow in any of the PMUs as expected. Figure 4-12 shows the phase angle difference between the two sides of the normally open tie switch (520-1048) which is 1.27 degrees.

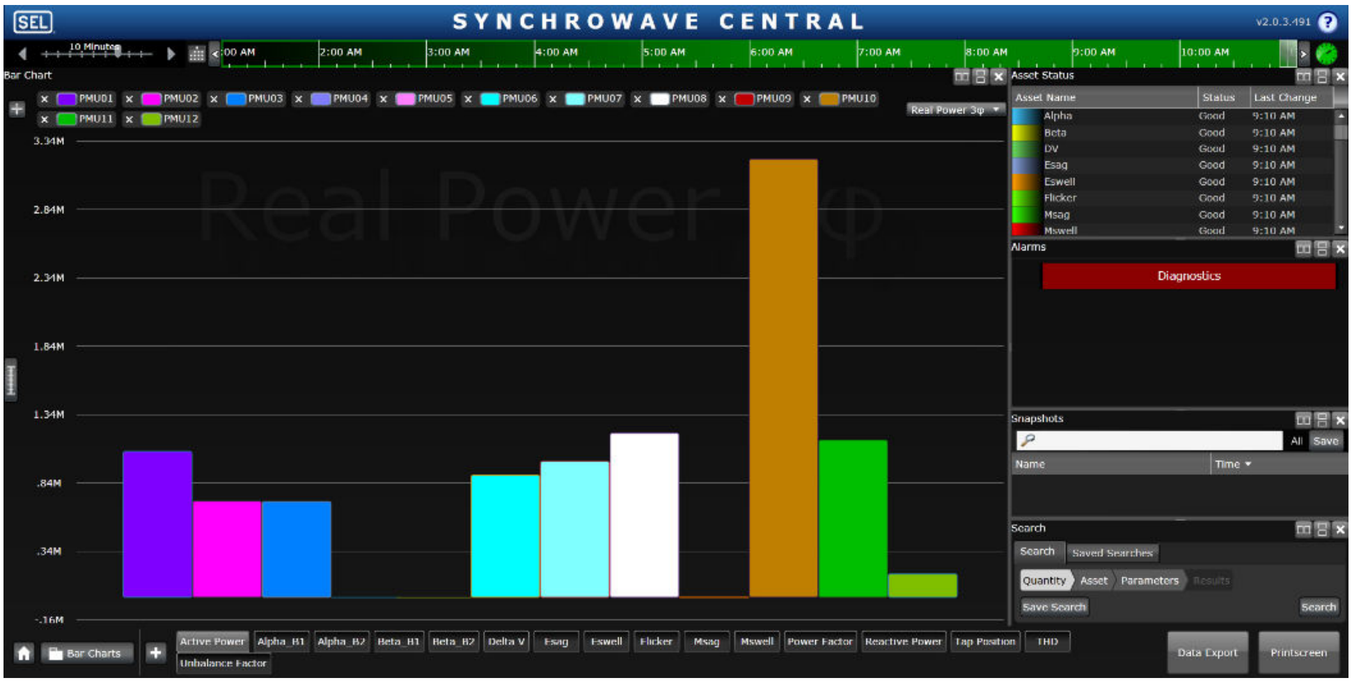


Figure 4-11. Active Powers during Low Loading without PV and with a Tie Switch Opened

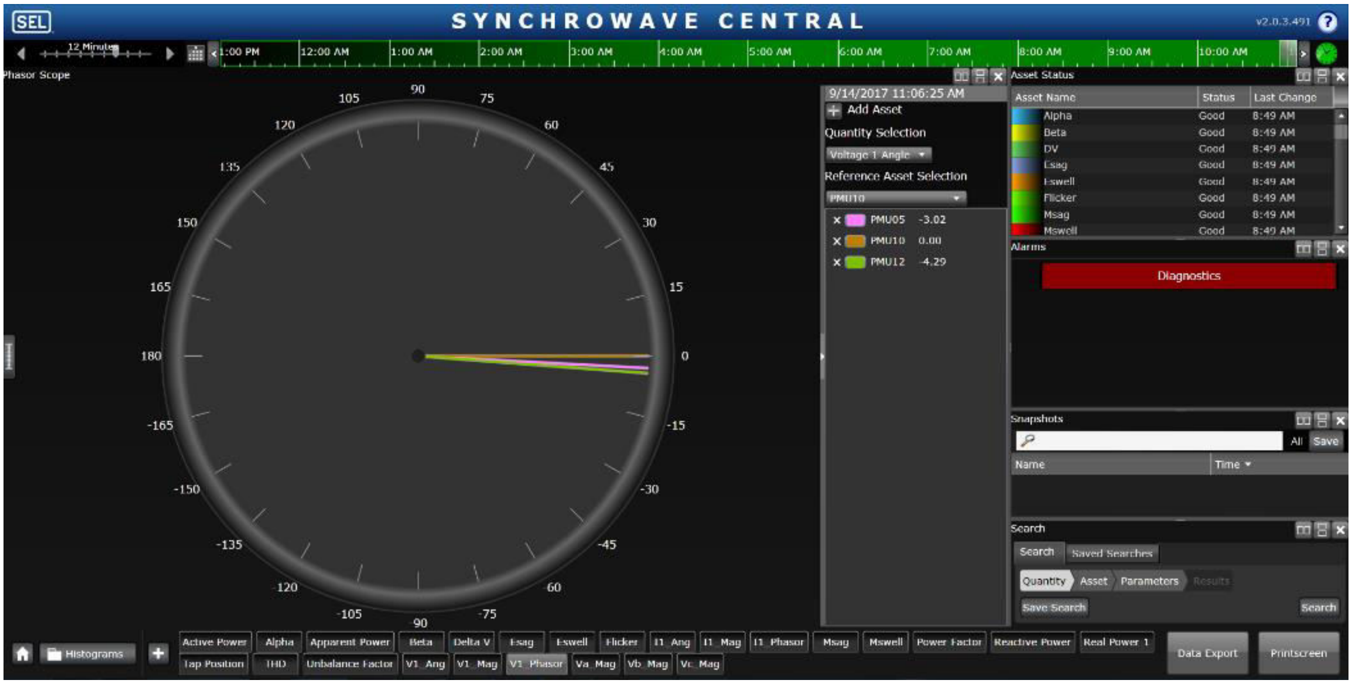


Figure 4-12. Phase Angles of the Two Sides of the 520-1048 during Low Loading without PV.

In the next step, suddenly, the maximum PV was added to the circuit. It can be seen in Figure 4-13 that this event created reverse power flow in the branch with PV (PMU 6, PMU 7, PMU 8, and PMU11, and PMU12).

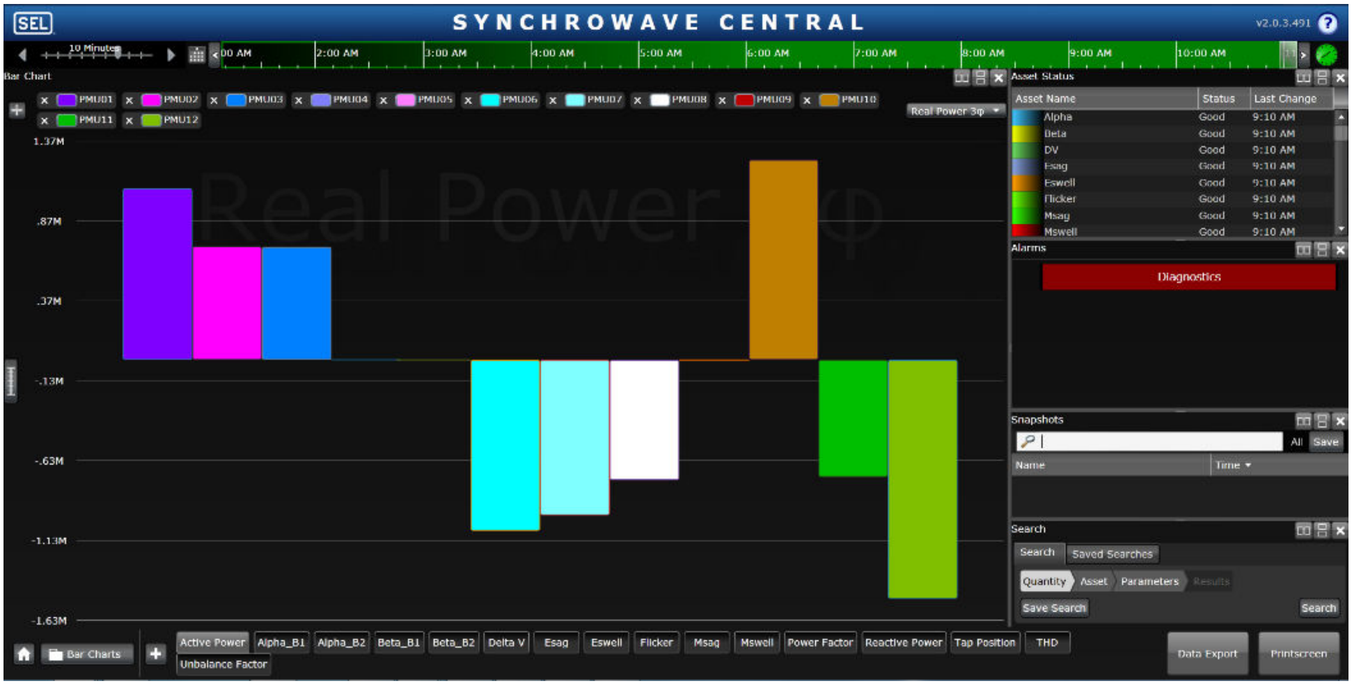


Figure 4-13. Active Powers after the Connection of the Maximum PV.

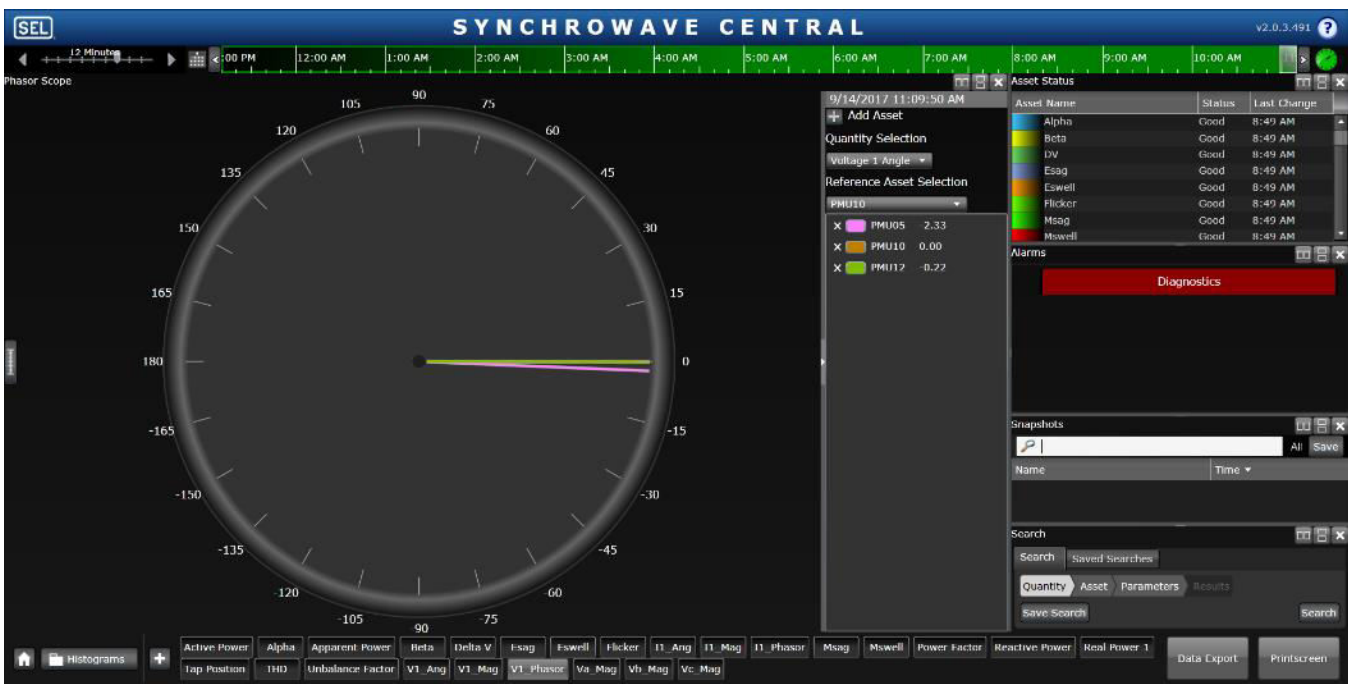


Figure 4-14. Phase Angles for the Two Sides of the 520-1048 after the Connection of the Maximum PV.

The phase angle across the open switch of the circuit was 2.11 degrees and the voltage magnitude difference is 0.5%, which gives the permission for closing REC 520-1048. The general requirements are voltage differences less than 5% and phase angle differences less than 10 degrees.

The following figures show the active powers and phase angles subsequent to the closing of REC 520-1048. It can be seen that this action caused a small amount of reverse power flow on the branch without PV (PMU 4 and PMU 5).

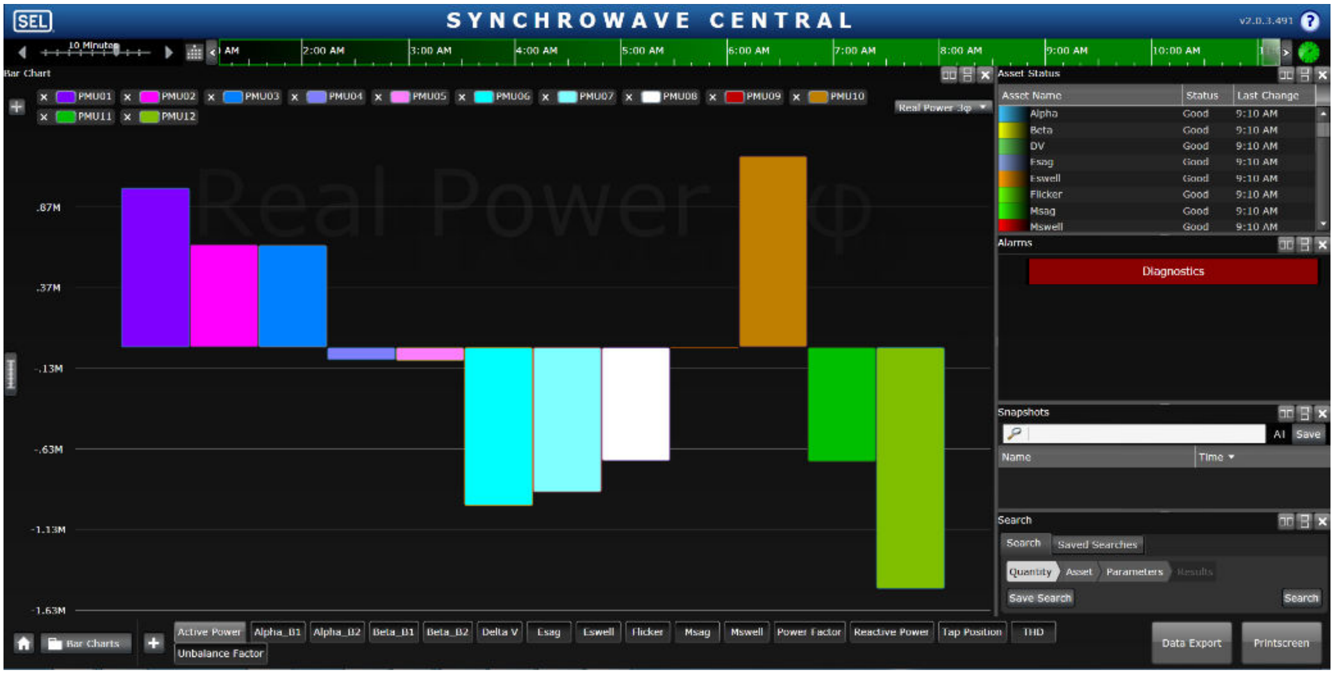


Figure 4-15. Active Powers after Closing 520-1048

Figure 4-16. Phase Angles for the Two Sides of the 520-1048 after Closing 520-1048

A recloser on the branch without PV was identified where the power flow is below 1 MW (REC 520-1045). This recloser was opened to perform a load transfer. The following figure show the active powers subsequent to the opening of REC 520-1045. It can be seen that this action causes a huge reverse power flow in PMU 5 and PMU 4.

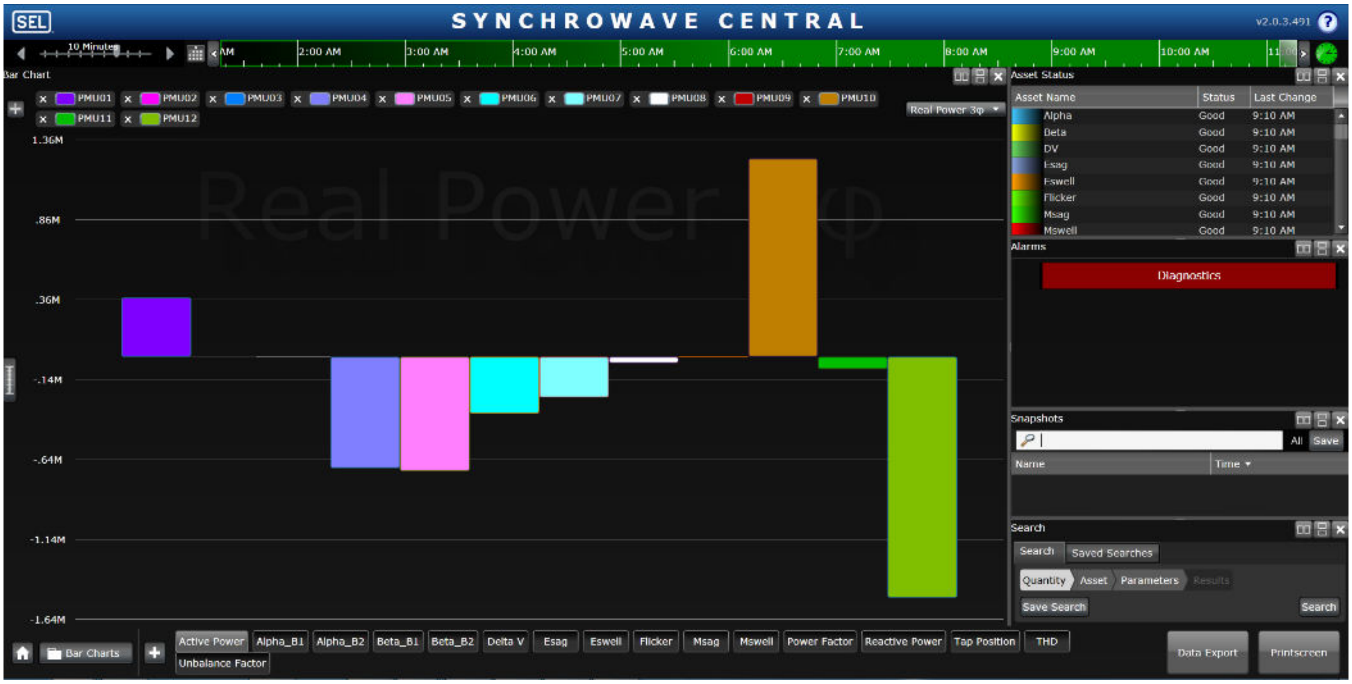


Figure 4-17. Active powers after the load transfer

To summarize, the sequence of actions during the load transfer was:

- Connecting PV to the System
- Closing tie switch 520-1048
- Opening recloser 520-1045

The PMU data including voltages, active powers, reactive powers, and tap positions are captured during the load transfer as shown in the following figures to better understand the effect of each action on the parameters of the system.

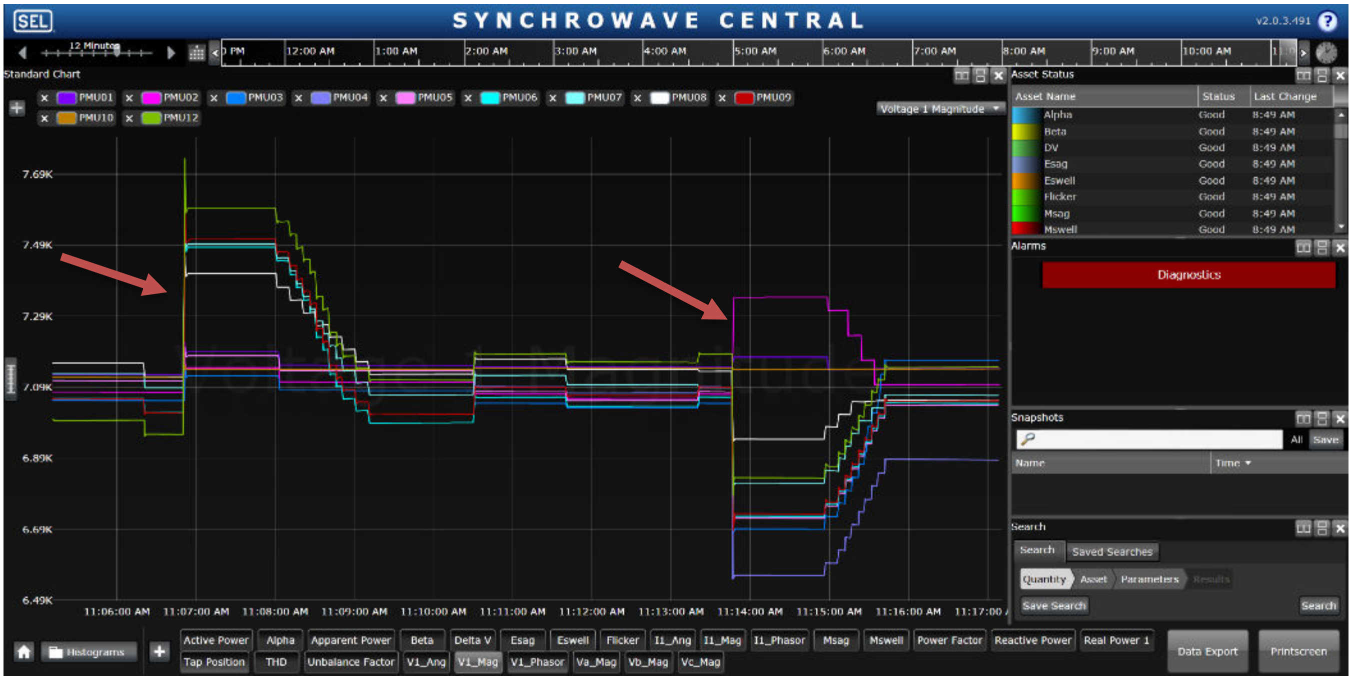


Figure 4-18. Magnitude of the Positive Voltages during the Load Transfer (changes are shown by arrows)

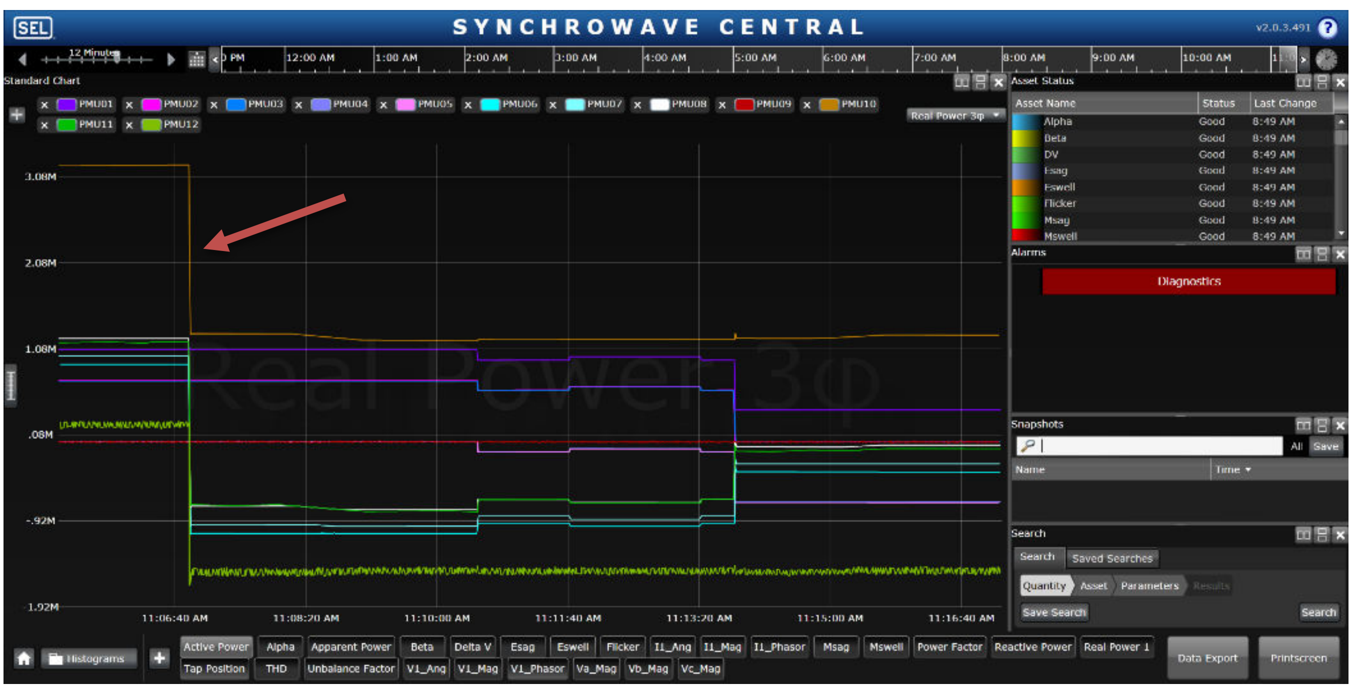


Figure 4-19. Active Powers during the Load Transfer (time of change is shown by the arrow)

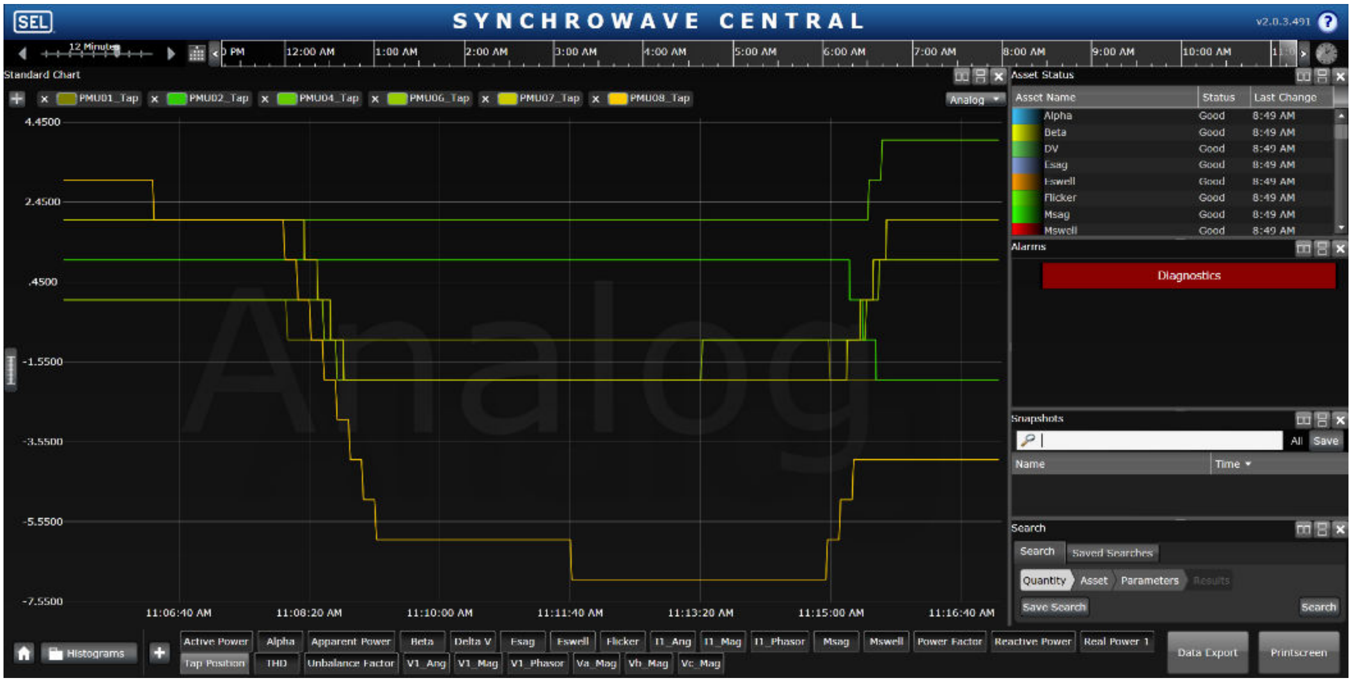


Figure 4-20. Tap Positions during the Load Transfer

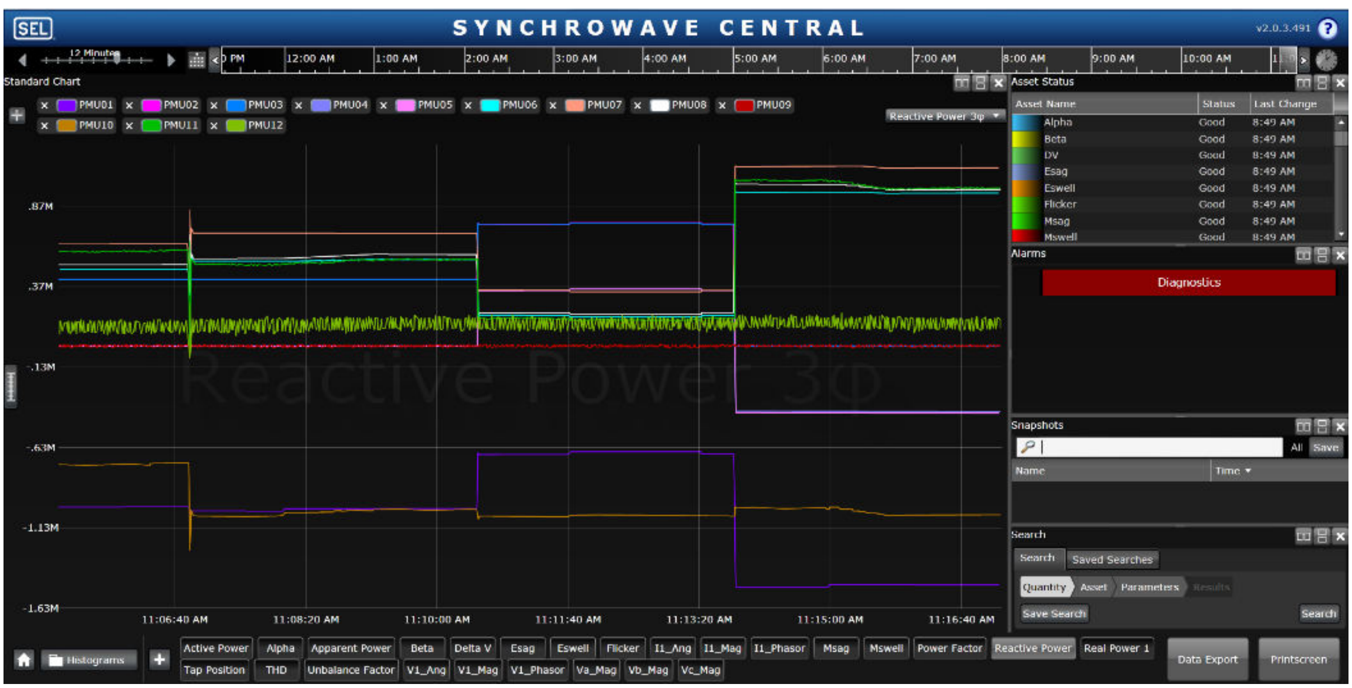


Figure 4-21. Reactive Powers during the Load Transfer

It can be seen from the visualization screen that PMUs can detect and visualize step changes in the load and resulted power flow variations.

4.1.3 Primary Asset Operation Monitoring and Diagnostics

The objective of this test category is to verify the streaming capability of the analog value assigned to the tap positions and THD.

4.1.3.1 Tap Position Streaming

Constant load (0.75 pu) profile was applied. Initially capacitor C1 and C3 were turned on. We turned off capacitor C1 and waited for the voltages to get to the steady state condition; then, turned it on and waited for the voltages to get to the steady state condition. Similar condition was repeated for C3, and the following measurements were captured:

- Magnitude of positive sequence voltage
- Magnitude of positive sequence current
- Active power
- Reactive power
- Tap positions for all voltage regulators

It should be noted that the sequence of capacitor switching actions were introduced to create dynamic events and to introduce disturbances that can be detected by the PMUs to test and evaluate the functionalities of the proposed monitoring and visualization schemes.

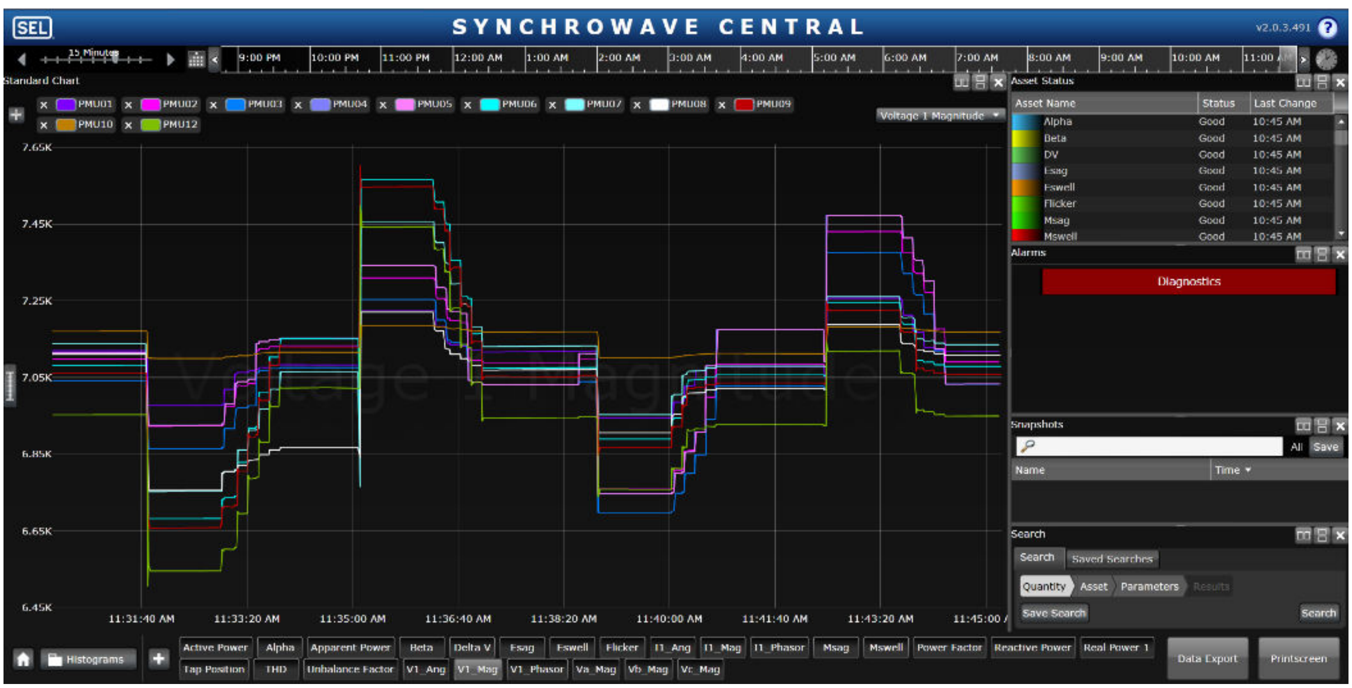


Figure 4-22. Magnitude of Positive Sequence Voltages Subsequent to Capacitor Switching

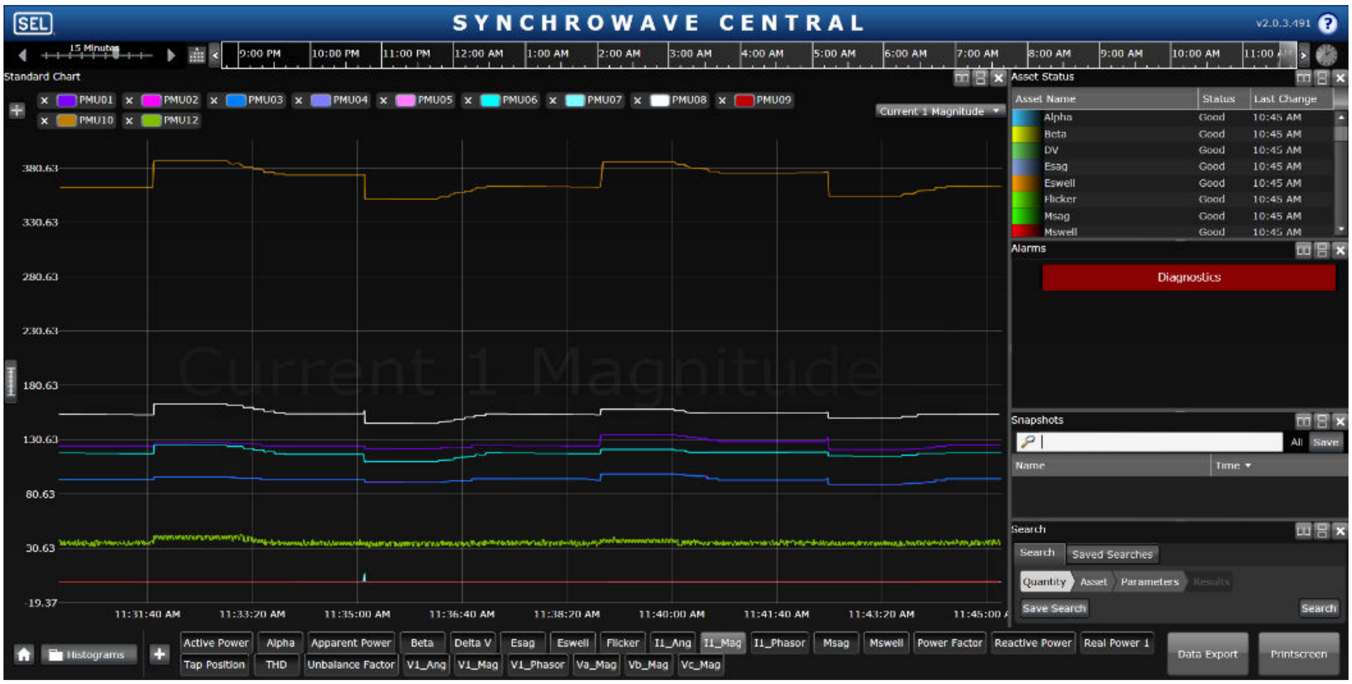


Figure 4-23. Magnitude of Positive Sequence Currents Subsequent to Capacitor Switching

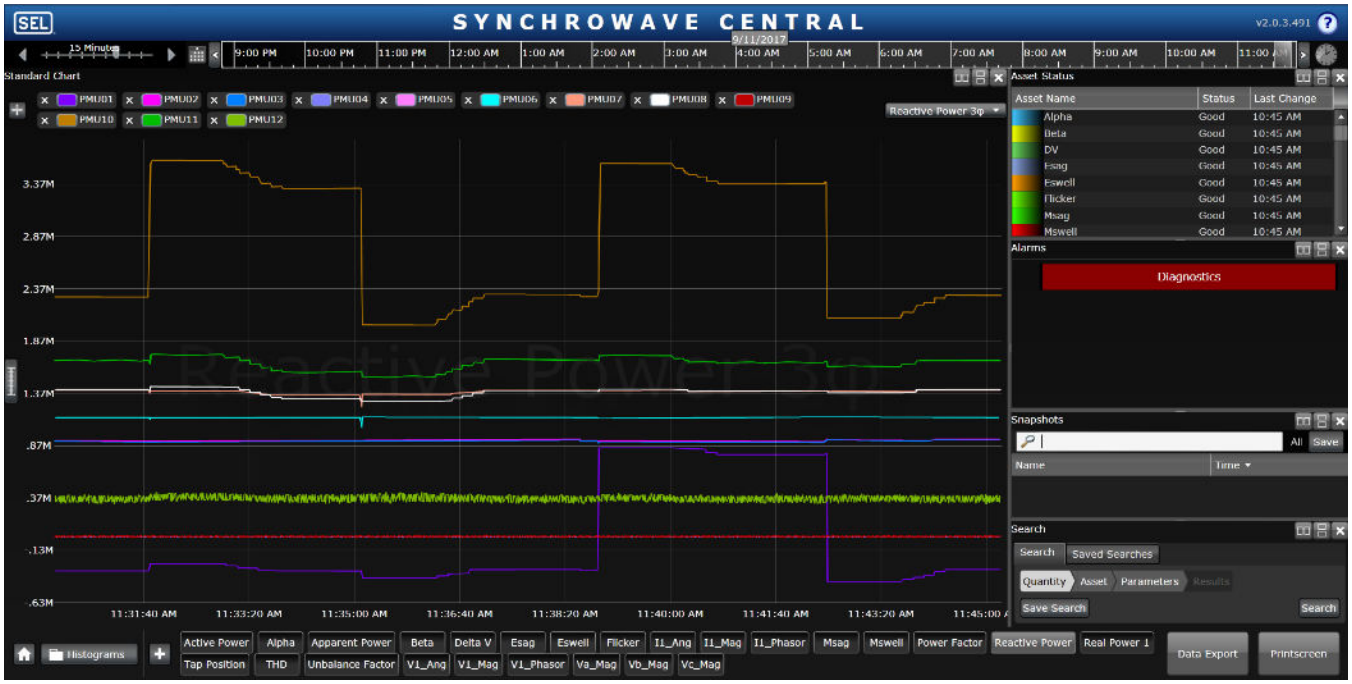


Figure 4-24. Reactive Powers Subsequent to Capacitor Switching On and Off

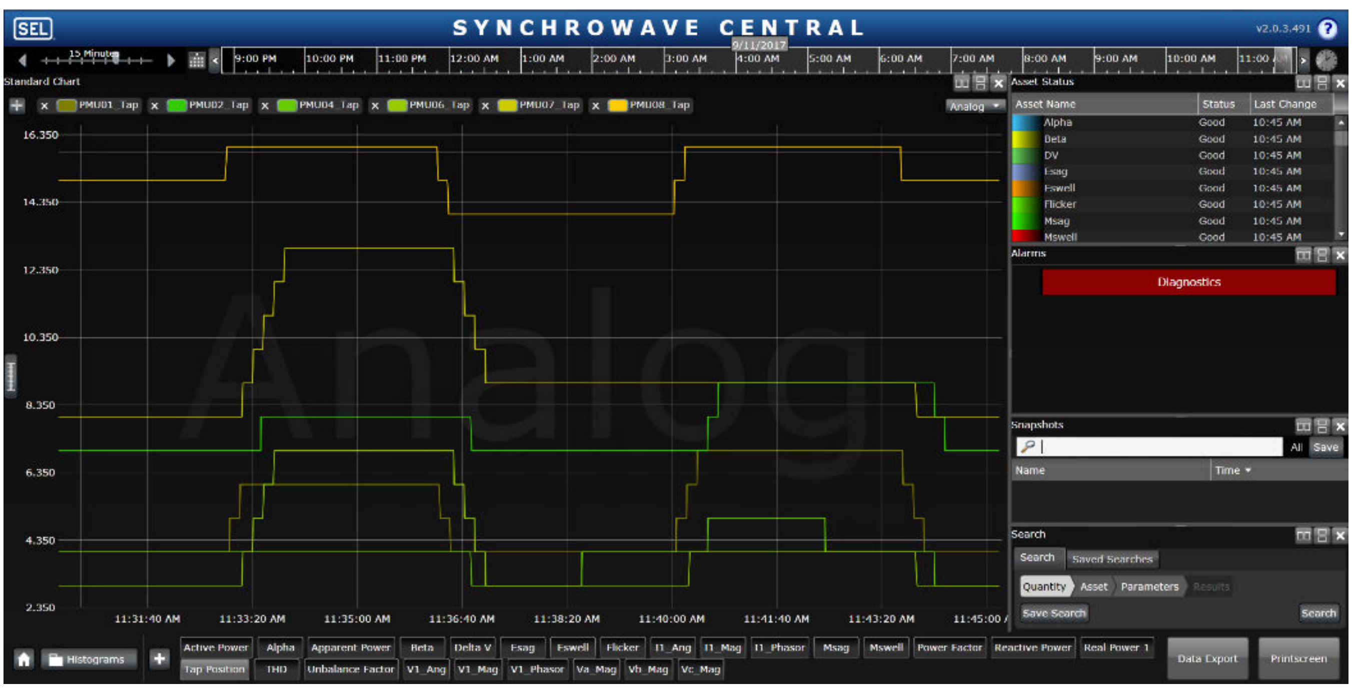


Figure 4-25. Tap Positions Subsequent to Capacitor Switching

4.1.3.2 THD Streaming

In this test, the constant load profile (0.5) was used with no PV. REC 520-1048 was in closed position. To investigate the THD level, 5th harmonic voltage component was added to the circuit, through non-linear harmonic load injection downstream of the voltage regulator 3, which increased the voltage as well as harmonics. The magnitude of the harmonic injection was increased (every 30 seconds) to 0.03 pu, 0.08 pu, 0.15 pu, and 0.3 pu of the fundamental component.

The following measurements were captured before and after the injection of the harmonics:

- Magnitude of positive sequence voltage
- THDs

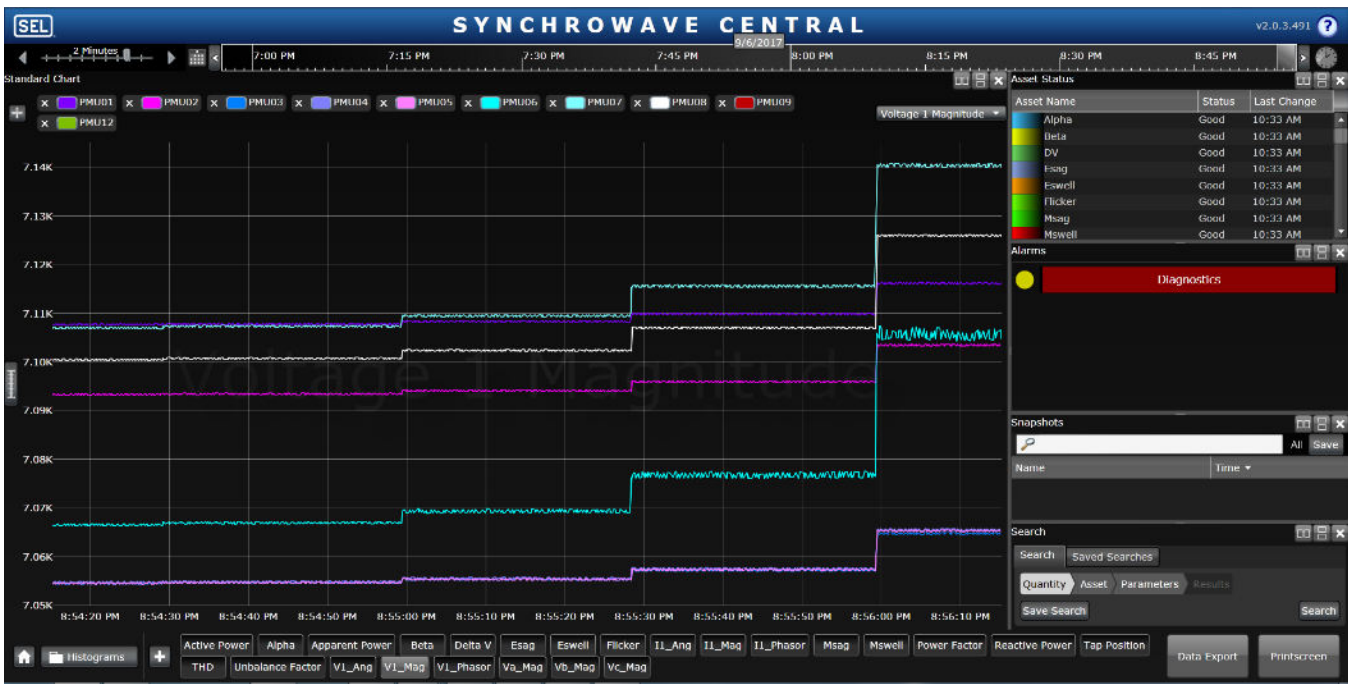


Figure 4-26. Magnitude of Positive Sequence Voltages Subsequent to Adding Harmonic Voltage

Figure 4-27. THDs Captured by Different PMUs

As expected, different PMUs depending on their location streamed different values of THD (the closer the PMU to the source of the harmonic, the larger the value of the THD). PMU5 is the closest PMU to the harmonic source; therefore, it observed the maximum THD value. To evaluate the performance of the THD streaming of the PMUs, the THD value obtained from PMU5 is compared with the injected harmonic.

Injected THD	**0.03**	**0.08**	**0.15**	**0.3**
Observed THD from PMU5	0.026	0.068	0.121	0.236

4.1.3.3 Sensitivity

The objective of this test category was to verify the capability of RTAC in the calculation of the following parameters and indices:

- Alpha factor (dV/dP) in pu/MW
- Beta factor (dV/dQ) in pu/Mvar

4.1.3.3.1 Calculation of Alpha and Beta

In this test, the summer load profile was run for 1 hour with summer PV profile and the following measurements were captured for all PMUs. The following parameters were captured accordingly:

- Magnitude of positive sequence voltage
- Alpha in the branch with PV (PMU 1, PMU 2, PMU 3, PMU 4, and PMU 5)
- Alpha in the branch without PV (PMU 8, PMU 11, PMU 7, and PMU 6)
- Beta in the branch with PV
- Beta in the branch without PV

Figure 4-28. Magnitude of Positive Sequence Voltages

The magnitude of positive sequence voltages are generally in the range of the rms circuit voltages, since the amount of zero sequence and negative sequence voltages are negligible.

In Figure 4-29, the sensitivity of different PMUs (in the branch without PV) is shown in bar graphs in the order of their distance to the substation circuit breaker. It can be seen that the sensitivity increases by getting away from the substation transformer toward the end of the circuit.

Similar behavior can be seen in the branch with PV as shown in Figure 4-30, but the PMU12 placed near the PV has a small sensitivity.

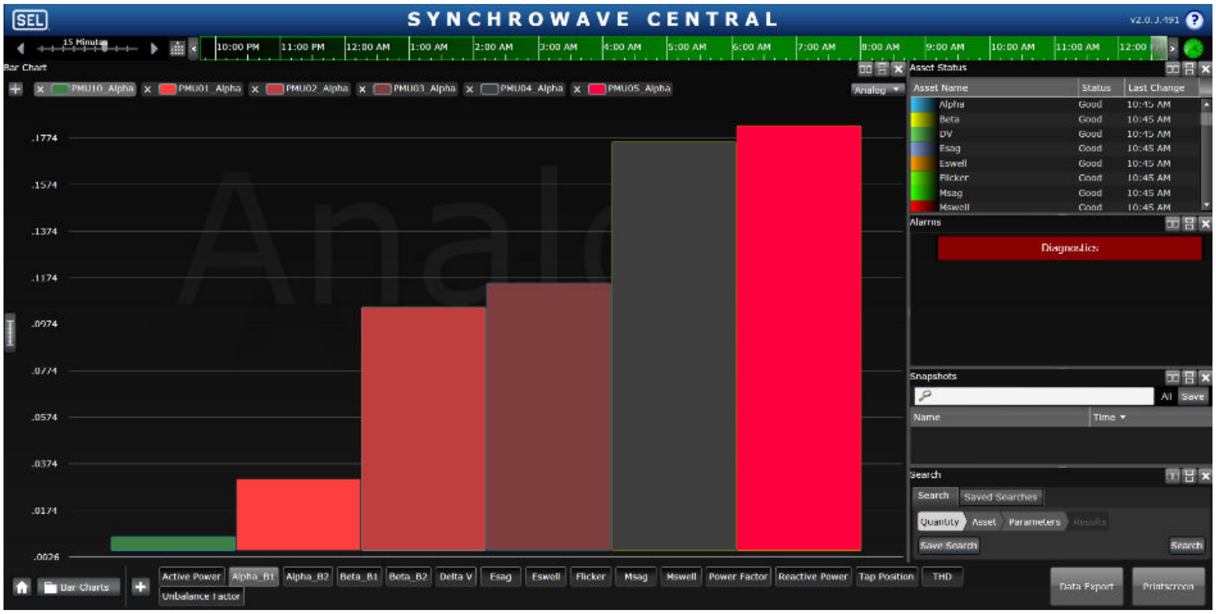


Figure 4-29. Demonstration of Changes in Alpha across the Branch without PV

Figure 4-30. Demonstration of Changes in Alpha across the Branch with PV

As observed, presence of PV system toward the end of the circuit create a less sensitive area. The PV system has contributed in strengthening the stiffness of the system.

Figure 4-31. Change in Beta across the Branch without PV

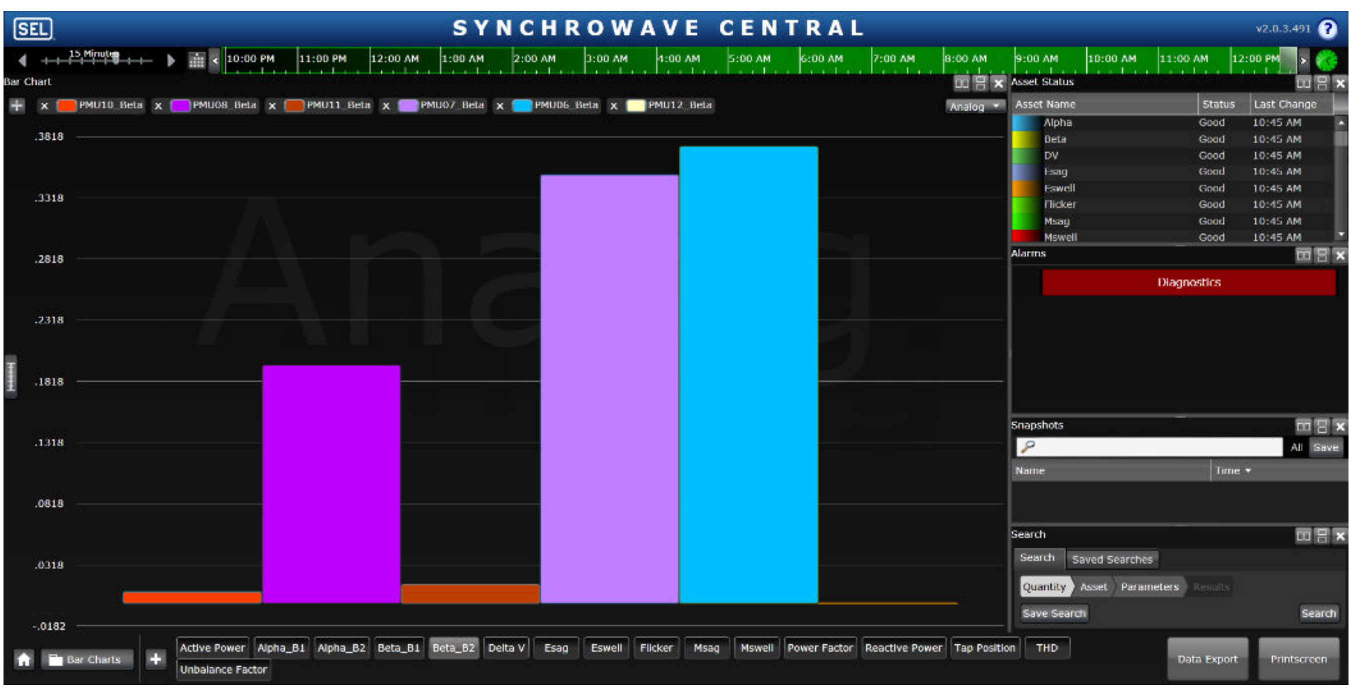


Figure 4-32. Change in Beta across the Branch with PV

Beta trend across the circuit is very similar to Alpha trend across the circuit; however, Beta is larger than Alpha. In this case, presence of the PV plant improved the system stiffness and reduce the sensitivity.

4.1.3.4 Faults

This section investigate the performance of the visualization in calculating the following parameters caused by different kind of faults and device malfunction

- Extreme Sag
- Extreme Swell
- Moderate Sag
- Moderate Swell
- Flickers
- Voltage unbalance

4.1.3.4.1 Calculation of Flickers

In this test case, C1 was turned off and on quickly. As shown in Figure 4-33, there are two voltage steps (falling and rising caused by turning off and on C1) in less than 2 seconds for all PMUs, which is qualified for a flicker. It can be seen in Figure 4-34 that this flicker is captured by visualization system and reported on the screen.

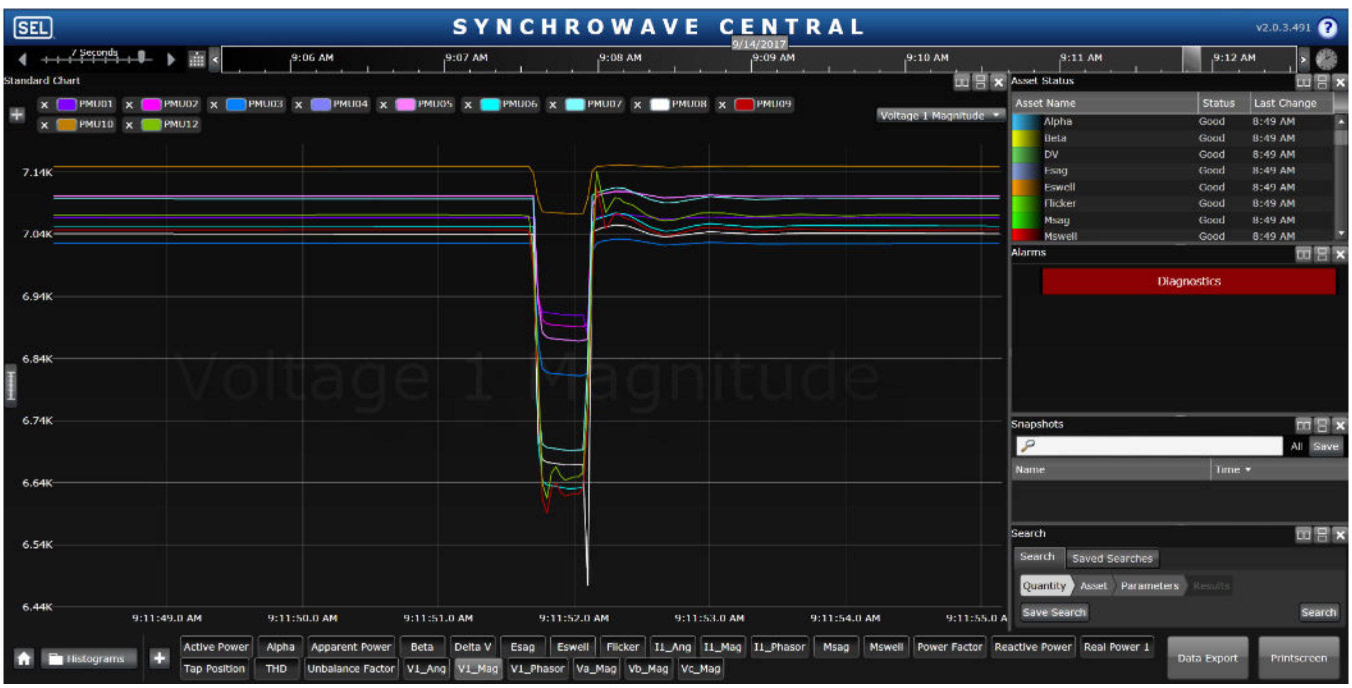


Figure 4-33. Magnitude of Positive Sequence Voltages

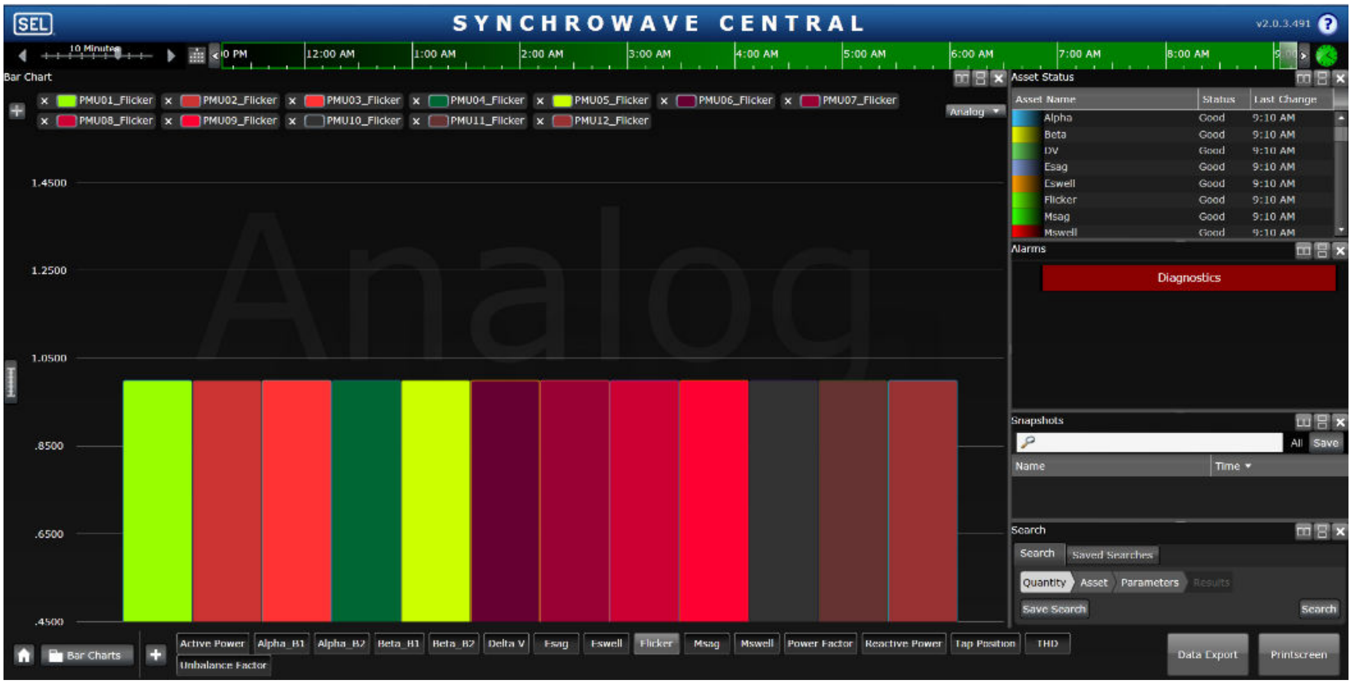


Figure 4-34. Flickers Subsequent to the Capacitor Switching

4.1.3.4.2 Calculations of Extreme Sag, Extreme Swell, Moderate Sag, and Moderate Swell

In this use case, we try to create a transient event to verify the performance of the RTAC in the calculation of extreme sag, extreme swell, moderate sag, and moderate swell.

4.1.4 Test Case 1

In this test, the summer load model was run with 2MW PV generation (PV protection settings are incorporated for the 2 MW system to match the IEEE 1547a (IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems) as shown in the following tables).

Table 4-1: Interconnection System Default Response to Abnormal Voltages [IEEE 1547a]

Default settings[a]		
Voltage range (% of base voltage[b])	Clearing time (s)	Clearing time: adjustable up to and including (s)
V < 45	0.16	0.16
45 ≤ V < 60	1	11
60 ≤ V < 88	2	21
110 < V < 120	1	13
V ≥ 120	0.16	0.16

[a] Under mutual agreement between the EPS and DR operators, other static or dynamic voltage and clearing time trip settings shall be permitted

[b] Base voltages are the nominal system voltages stated in ANSI C84.1-2011, Table 1.

Table 4-2: Interconnection System Default Response to Abnormal Frequencies [IEEE 1457a]

	Default settings		Ranges of adjustability	
Function	Frequency (Hz)	Clearing time (s)	Frequency (Hz)	Clearing time (s) adjustable up to and including
UF1	< 57	0.16	56 – 60	10
UF2	< 59.5	2	56 – 60	300
OF1	> 60.5	2	60 – 64	300
OF2	> 62	0.16	60 – 64	10

A single line to ground fault was applied at Bus 101 (upstream of the VR5) for 35 cycles immediately downstream of the REC5 and the following measurements were captured: (note that REC5 is expected to trip and clear fault after 20 cycle – this value represent typical operation time of distribution protection schemes).

- Magnitude of positive sequence voltage
- Extreme sag
- Extreme swell
- Moderate sag
- Moderate swell

Figure 4-35 and Figure 4-36 show the magnitude of voltage and current subsequent to this fault. It can be seen in Figure 4-35 that there is an extreme voltage sag for PMU 1, PMU 2, PMU 3, PMU 4, and PMU5, which is compatible with the results obtained from RTAC in Figure 4-37. The level of voltage sag and depth of voltages characterize the severity. During this fault, the PV did not trip.

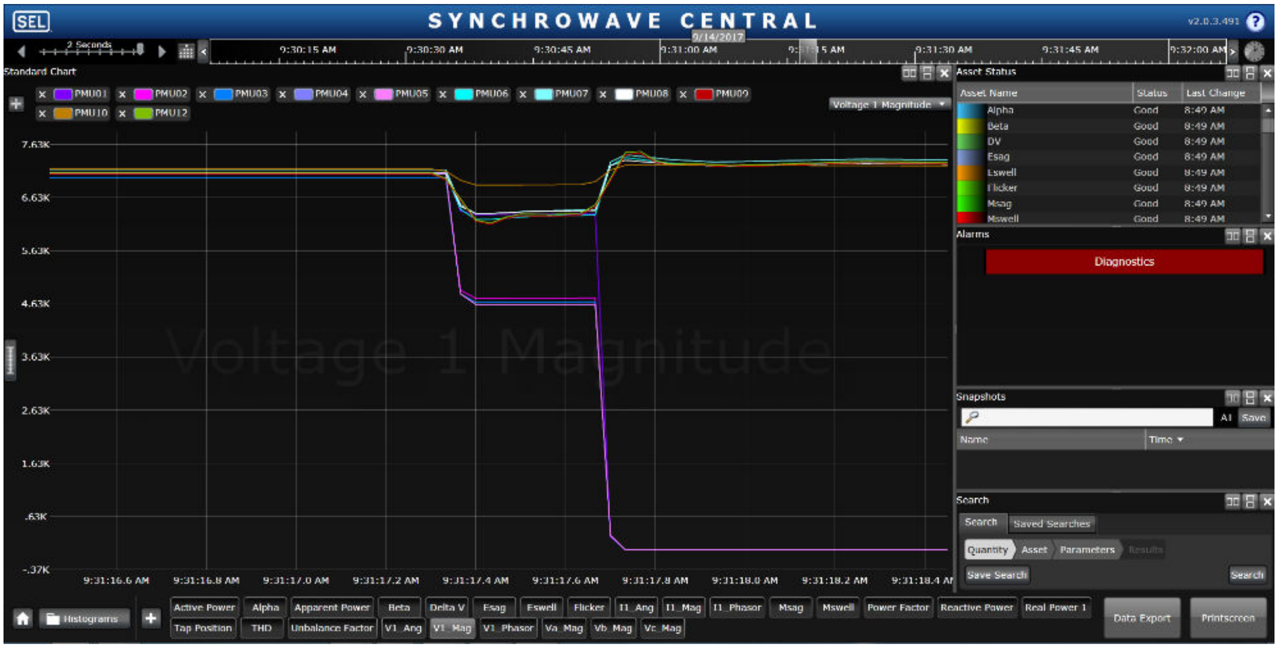


Figure 4-35. Magnitude of the Positive Sequence Voltages

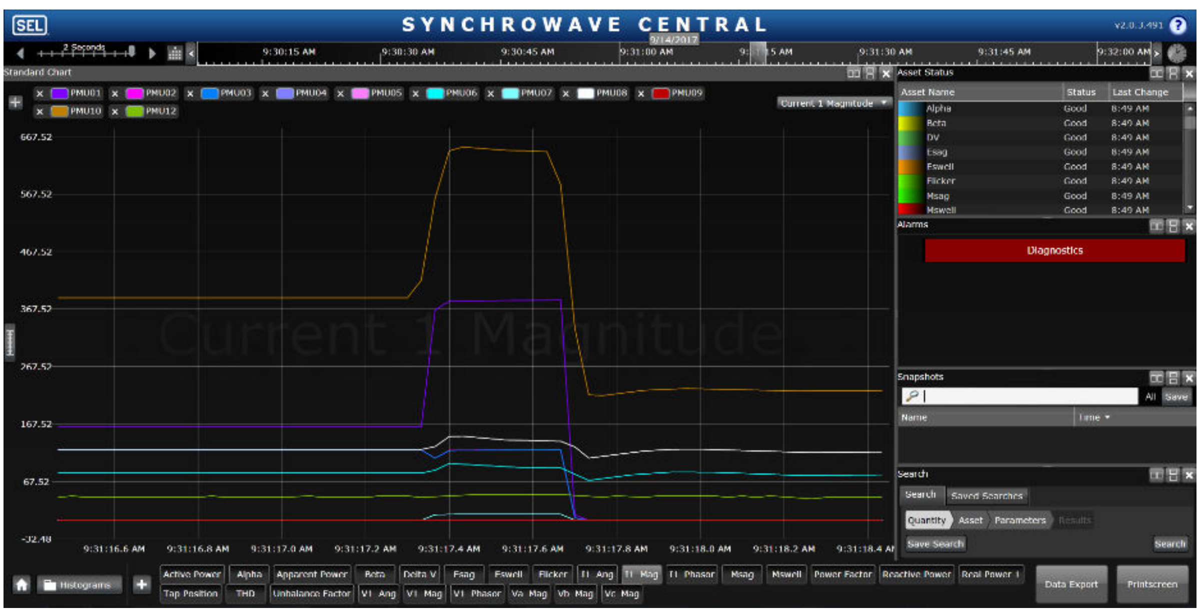


Figure 4-36. Magnitude of Positive Sequence Currents

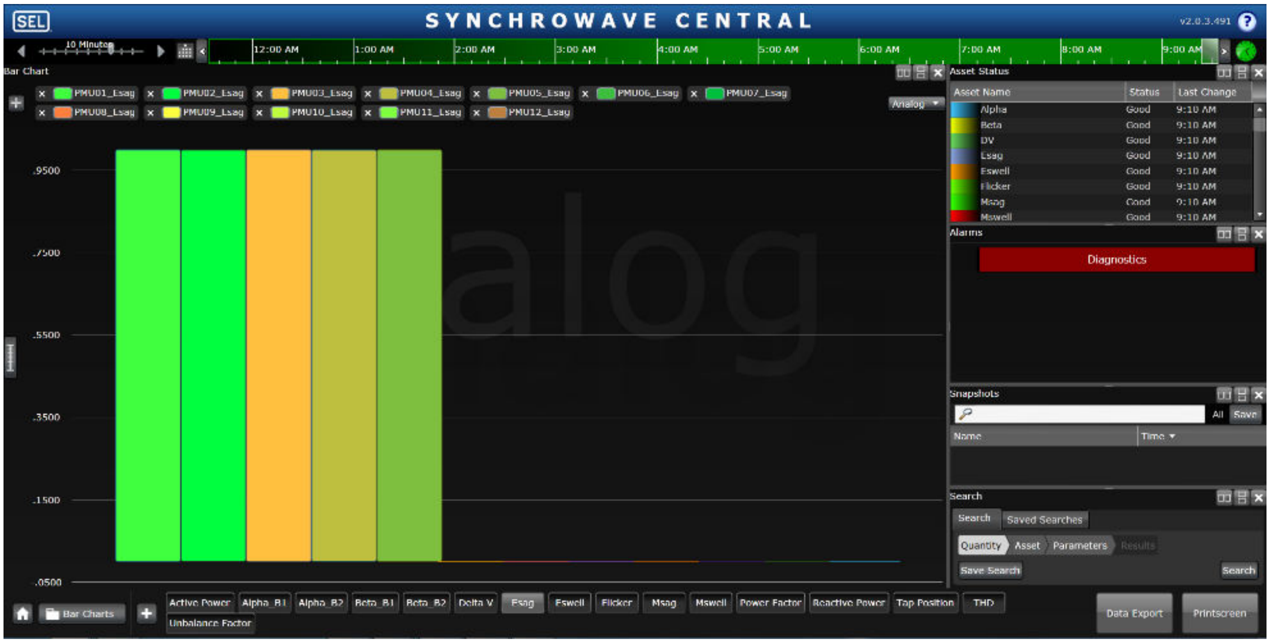


Figure 4-37. Extreme Voltage Sag Statistics

Then, the similar test was run for a two-line to ground fault (applying for 35 cycles immediately downstream of the REC5) and the following measurements were captured: (note that REC5 is expected to trip and clear fault after 8 cycles).

- Magnitude of positive sequence voltage
- Extreme sag
- Extreme swell
- Moderate sag
- Moderate swell

Similar to the previous test, it can be observed that this fault causes extreme voltage sags in PMU 2, PMU 3, PMU 4, and PMU5, which is compatible with the results obtained from visualization in Figure 4-40. During this fault, the PV did not trip.

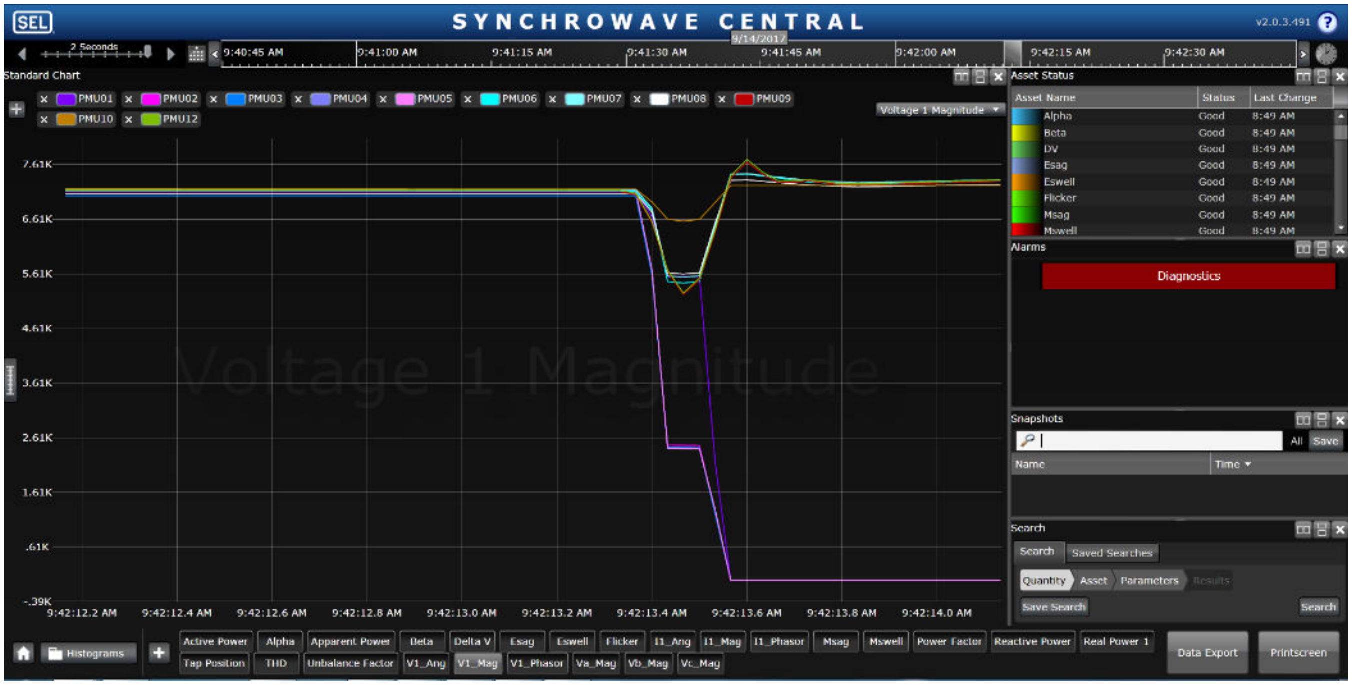


Figure 4-38. Magnitude of Positive Sequence Voltages

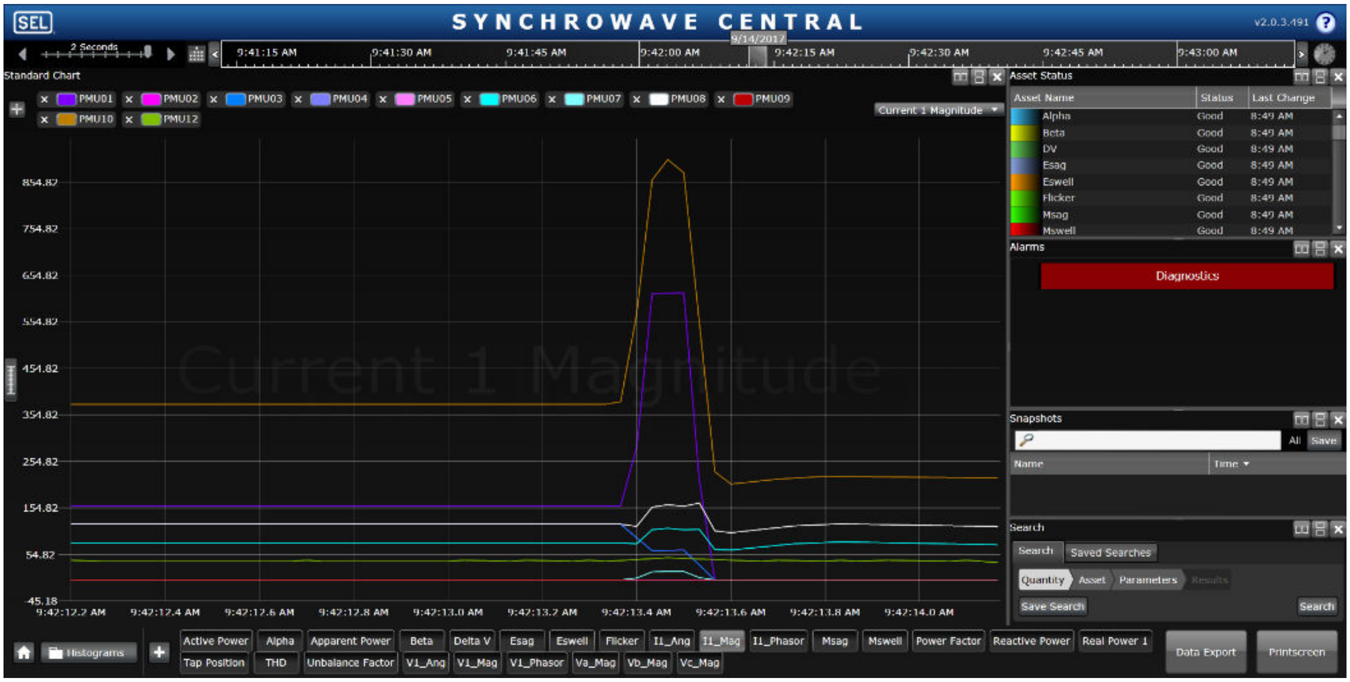


Figure 4-39. Magnitude of Positive Sequence Currents

Figure 4-40. Extreme Voltage Sag Statistics

4.1.5 Test Case 2

In this test, the summer load model performed with 2MW PV generation (PV protection settings are incorporated for the 2 MW system to match the IEEE 1547a). A three-phase fault was applied for 10 cycles close to the REC1 (located at Bus N06) and the following measurements were captured:

- Magnitude of positive sequence voltage
- Extreme sag
- Extreme swell
- Moderate sag
- Moderate swell

This fault generated a very quick voltage variation. Based on our definition from voltage sag and swell, this voltage variation cannot be considered as a voltage sag because it was very fast. RTAC did not report this event as voltage sag because the duration of violating voltage sag threshold (0.2 pu) wasn't more than 10 cycles.

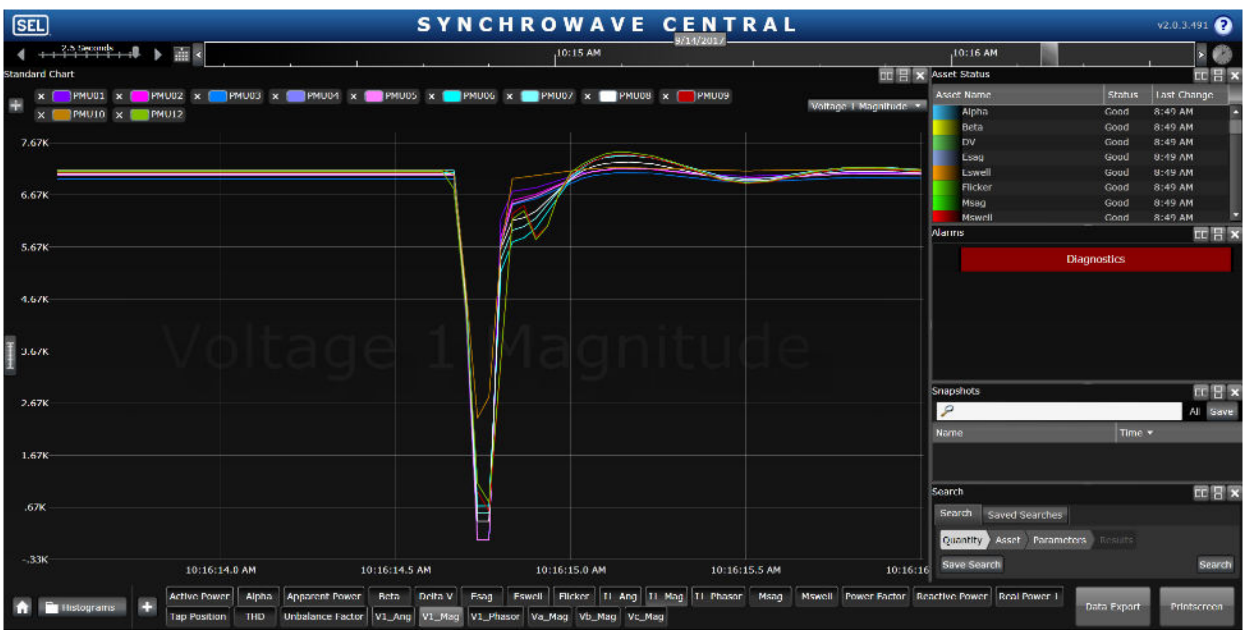


Figure 4-41. Magnitude of Positive Sequence Voltages

From the magnitude of the positive sequence current (as captured below) the fault location can be identified.

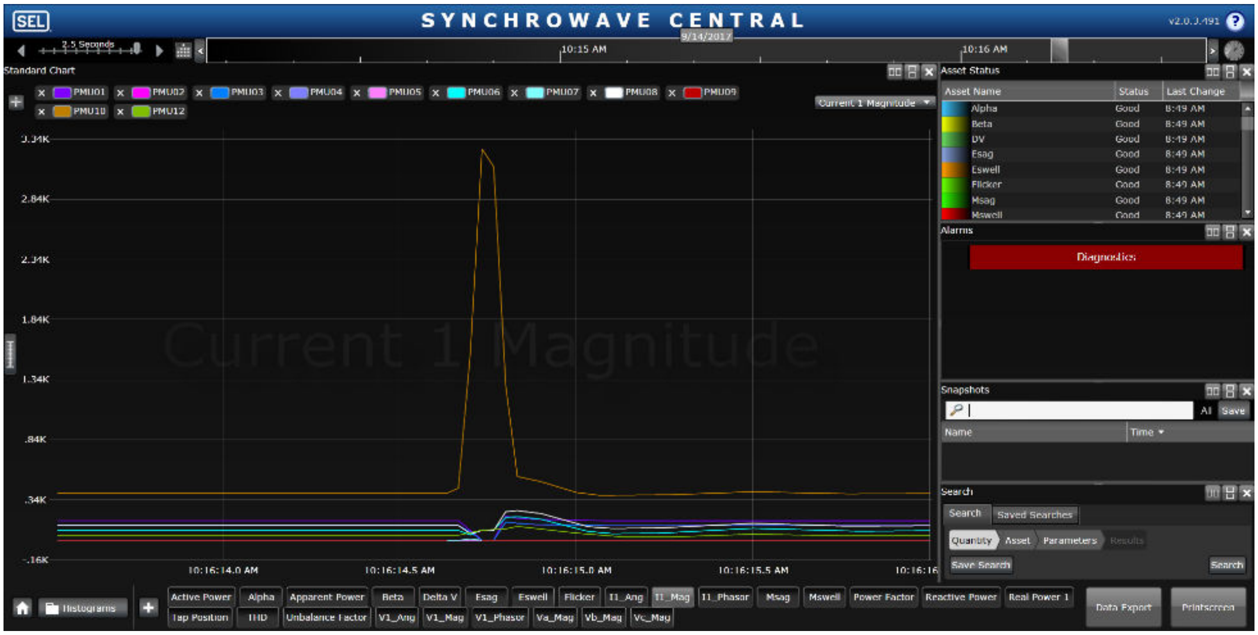


Figure 4-42. Magnitude of Positive Sequence Currents

This fault also did not trip the PV.

4.1.6 Test Case 3

In this test, the summer load model was run with 2MW PV generation (PV protection settings are incorporated for the 2 MW system to match the IEEE 1547a). A single line to ground fault (permanent) was applied close to DVC (N117) and the following measurements were captured:

- Magnitude of positive sequence voltage
- Extreme sag
- Extreme swell
- Moderate sag
- Moderate swell

Figure 4-43 shows that the PMU 12, PMU 9, PMU 8, and PMU 7 experienced a moderate voltage sag, which is compatible with the results obtained from RTAC in Figure 4-45. The main reason is that those PMUs were located electrically farther from the fault. This fault tripped the PV.

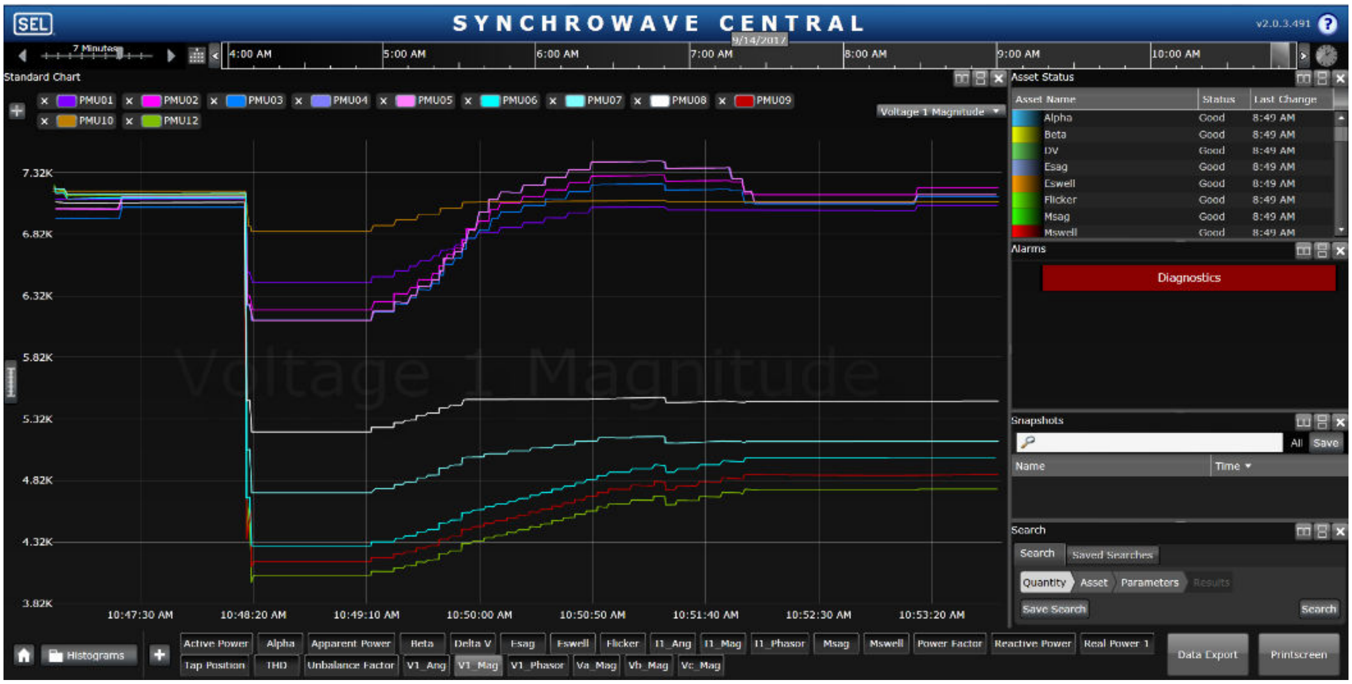


Figure 4-43. Magnitude of Positive Sequence Voltages

The above visualization screen can be utilized for fault detection and analysis. The level of voltage changes (voltage sag level) can be correlated with the fault type and fault locations.

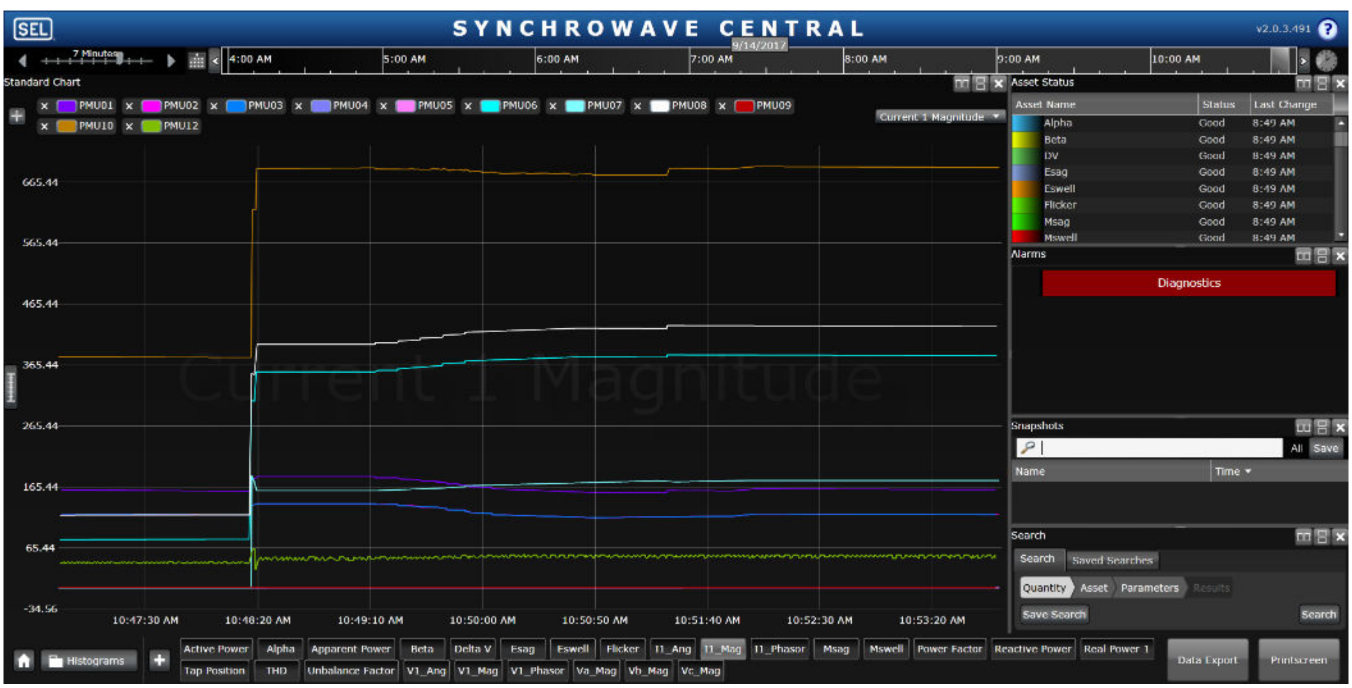


Figure 4-44. Magnitude of Positive Sequence Currents

As shown in the above figure, the PMU located electrically closer to the fault location showed the highest change in current.

Figure 4-45. Moderate Voltage Sag Statistics

4.2 Circuit 2 and Circuit 3 Test Results

A simplified single line diagram of the circuits 2 and 3 in Sub 2 is shown in Figure 4-46. The single line diagram is an overall representation of the model built in the RTDS environment for the laboratory testing and evaluations.

As indicated in this figure, there is a 6 MW PV system on circuit 3, located downstream of the circuit breaker CB3 and two generators downstream of the CB2. There is a normally open tie switch (CB0T21) between the two circuits. For load transfer cases, the tie switch can be closed and one of the upstream reclosers can be opened to change the load flow and voltage profile of the circuit.

Circuit 2 has one voltage regulator (VR1) and circuit 3 has two voltage regulators (VR2, and VR3). For the purpose of this study, this circuit has been modeled in RSCAD. 12 PMUs including 8 simulated PMUs (PMU1 to PMU8) and 4 physical PMUs (PMU9 to PMU12) are located at various nodes in the study system to facilitate system monitoring during the tests.

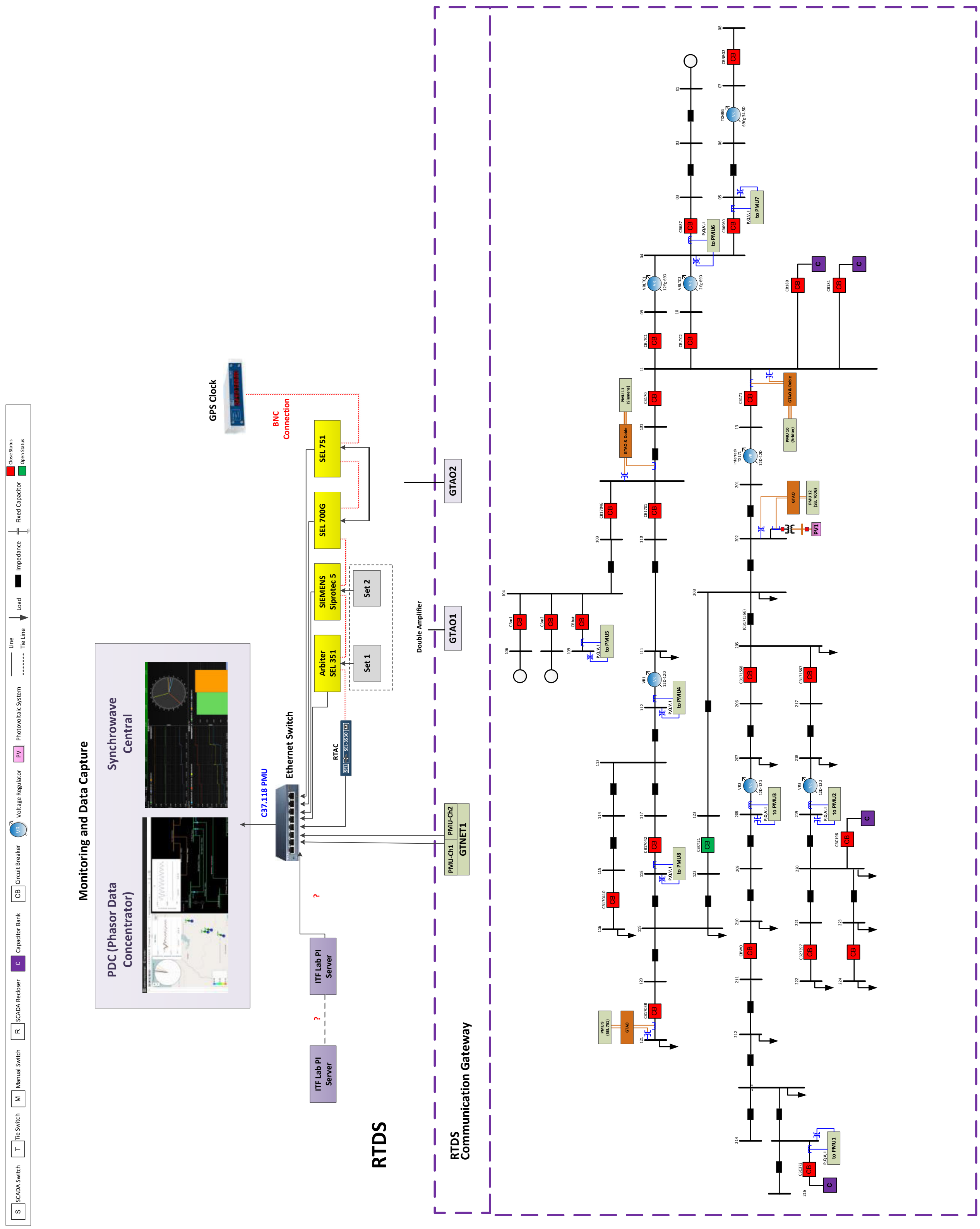


Figure 4-46. Single Line Diagram and PMU Locations of Circuit 2 and Circuit 3

In the following section, different case studies are presented to study the behavior of circuit 2 and 3.

4.2.1 Voltage/Power Flow Monitoring for Summer Load and with PV

In this case study the voltages, currents, real, and reactive power of different PMUs are captured, while the circuit was run with summer load profile and PV.

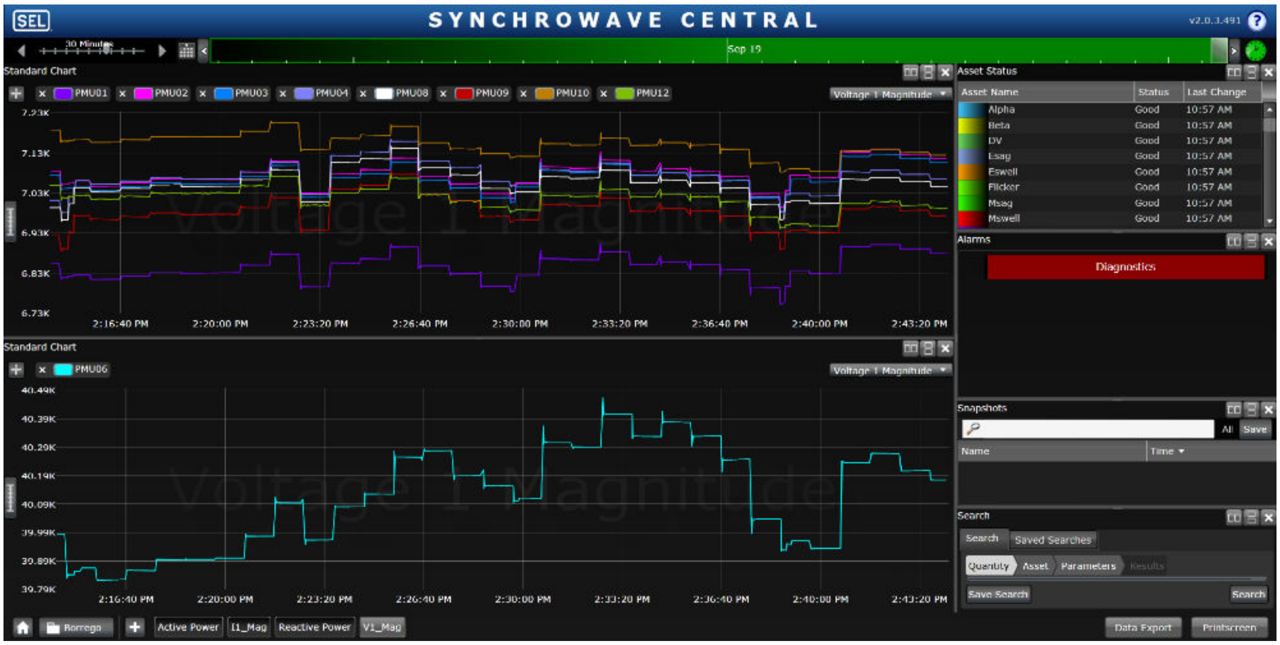


Figure 4-47. Magnitude of Positive Sequence Voltages

The proposed visualization screens and their applications are similar to the ones utilized for analysis of circuit 1. Each measurement screen provides one way of visualizing circuit events and dynamic nature of the disturb-ances.

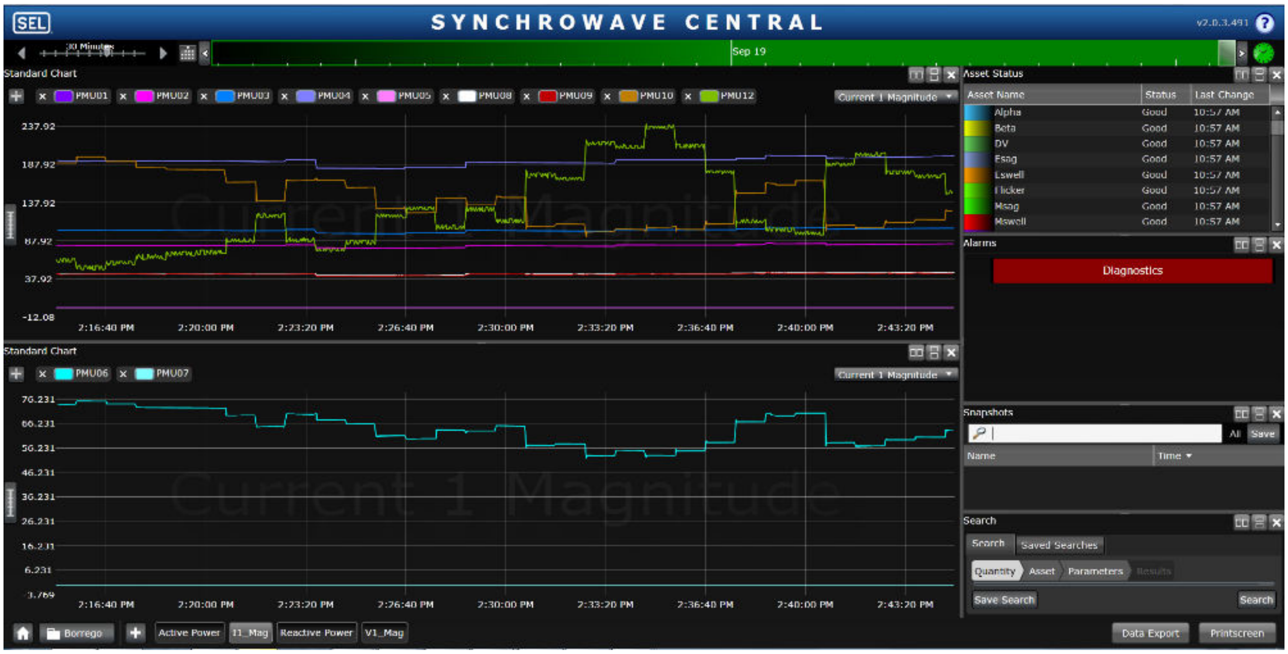


Figure 4-48. Magnitude of Positive Sequence Currents

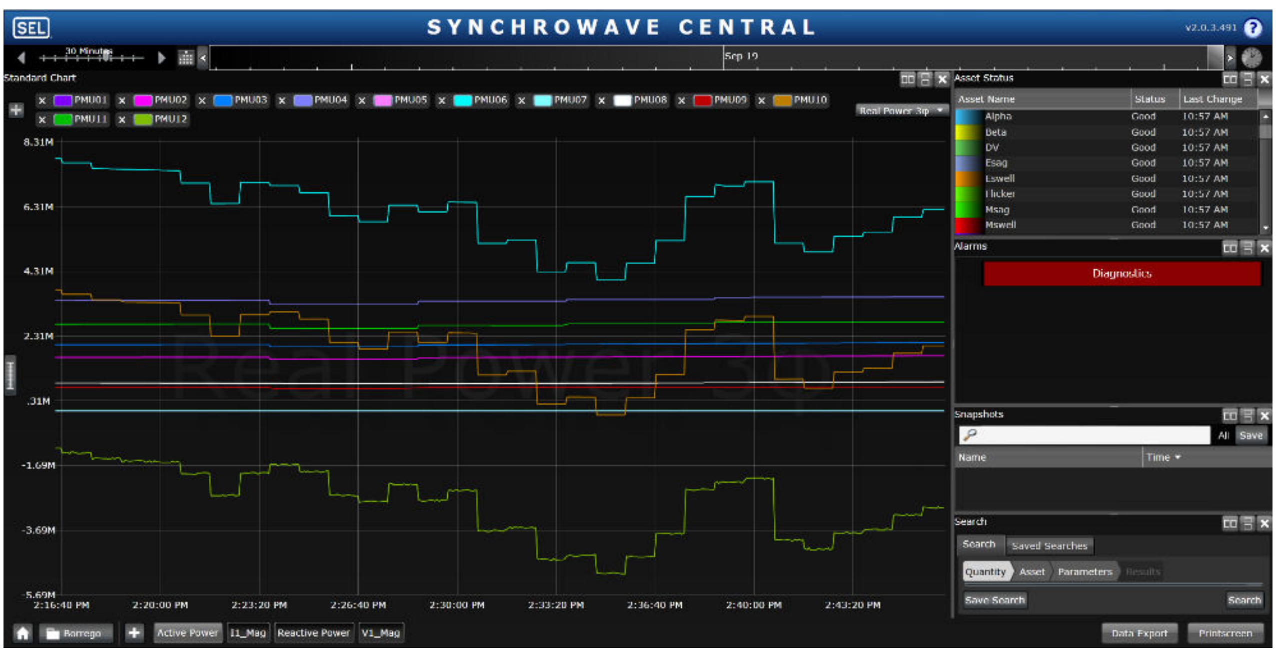


Figure 4-49. Active Powers

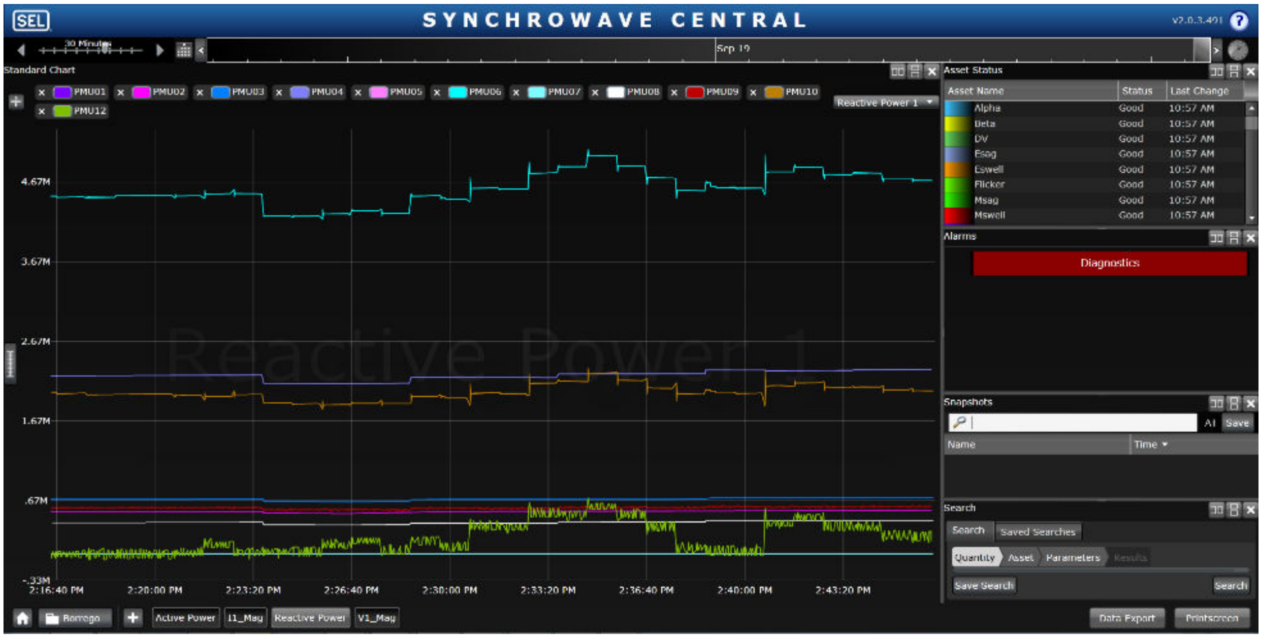


Figure 4-50. Reactive Powers

The approaches utilized in implementing and analysis the screens were generally similar to circuit 1. However, because of the availability of two diesel generators and significantly higher PV generation on circuit 2 and circuit 3, they were used to perform test cases associated with islanding and visualization of stability issues.

4.2.2 Primary Asset Operation Monitoring and Diagnostics

4.2.2.1 Load Transfer

In this case study, the loads were set at 0.75 pu and the PV was set at its maximum. The following figure shows the active power flow at different PMUs. It can be seen that there is reverse power flow in the PMUs close to the PV.

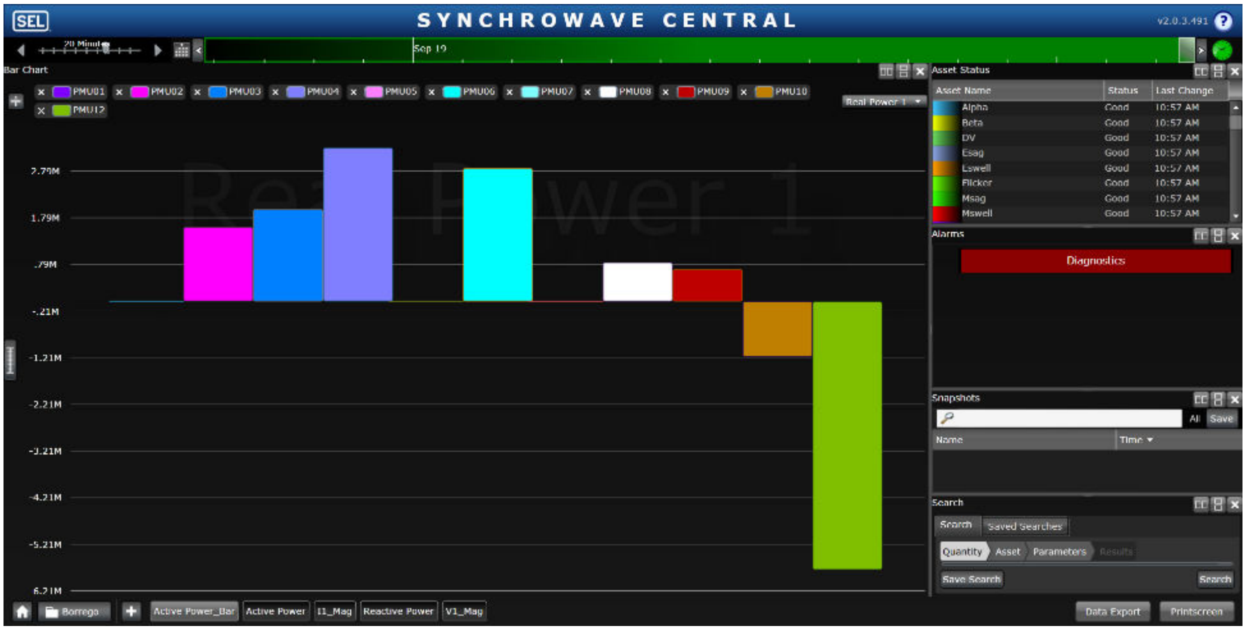


Figure 4-51. Active Powers of Different PMUs

The tie switch between two circuits was closed, and we can observe that this action created a reverse power flow in circuit 2.

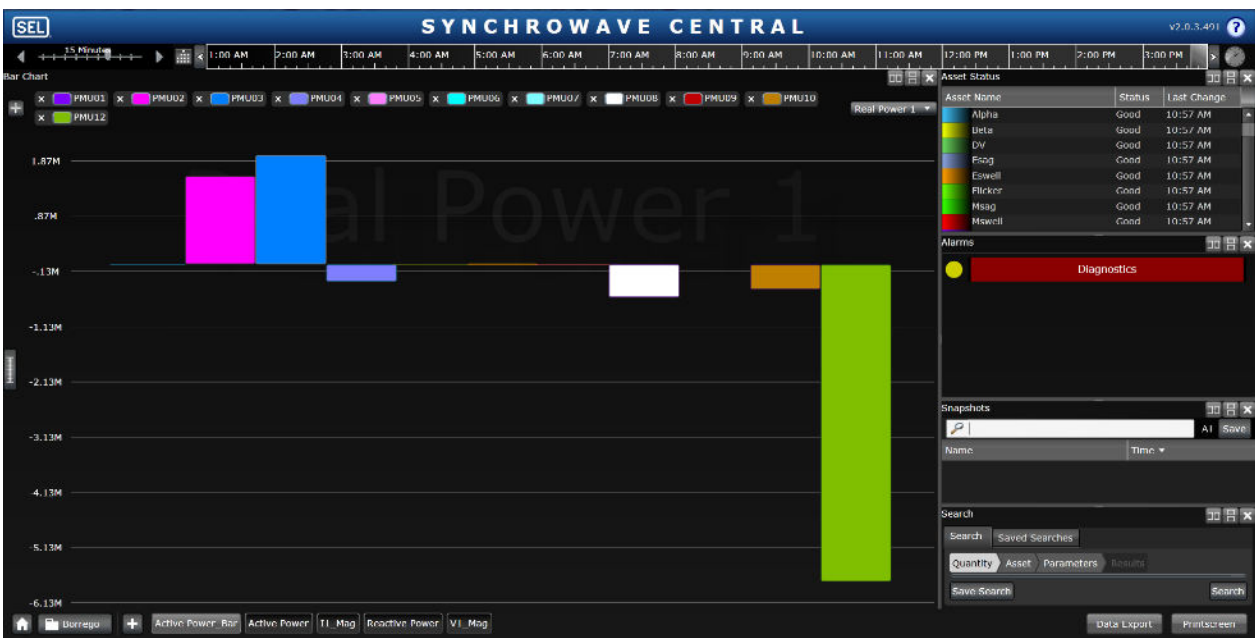


Figure 4-52. Active Powers of Different PMUs Subsequent to the Closing of the Tie Switch

Then, the recloser 1701 on the second branch was opened to perform the load transfer.

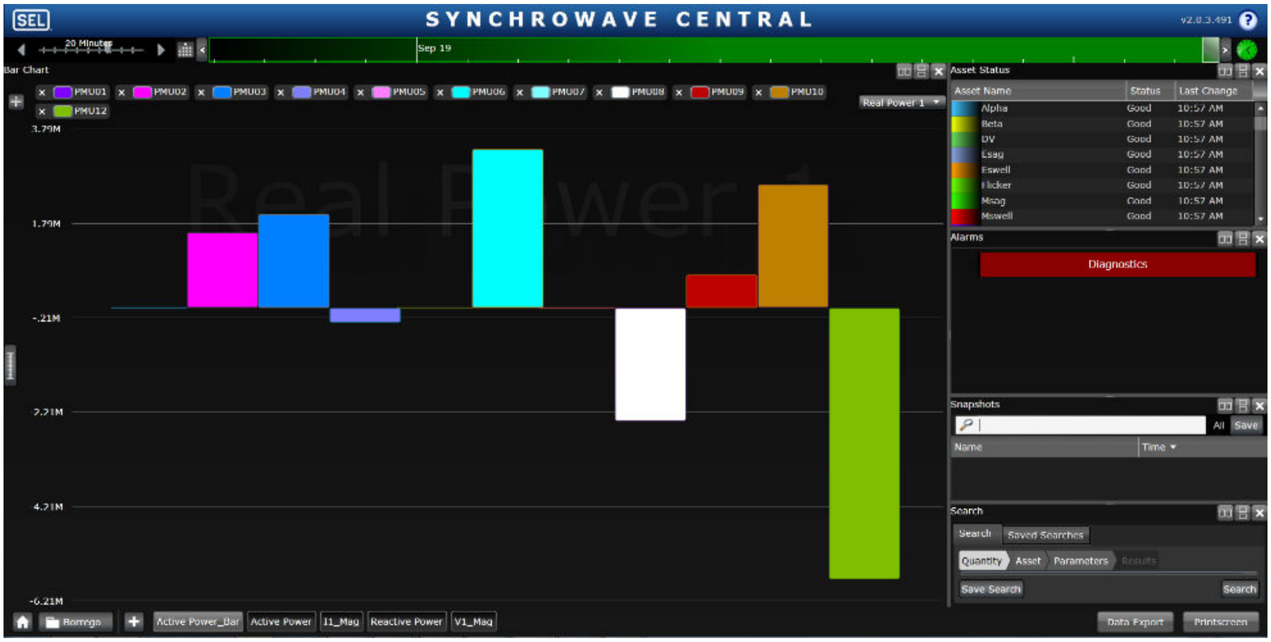


Figure 4-53. Active Powers of Different PMUs Subsequent to the Load Transfer

However, after the load transfer the voltages were out of the permissible range, because of the significant reduction in load. Therefore, the load shedding needs to be done to bring back the voltages to the standard limits.

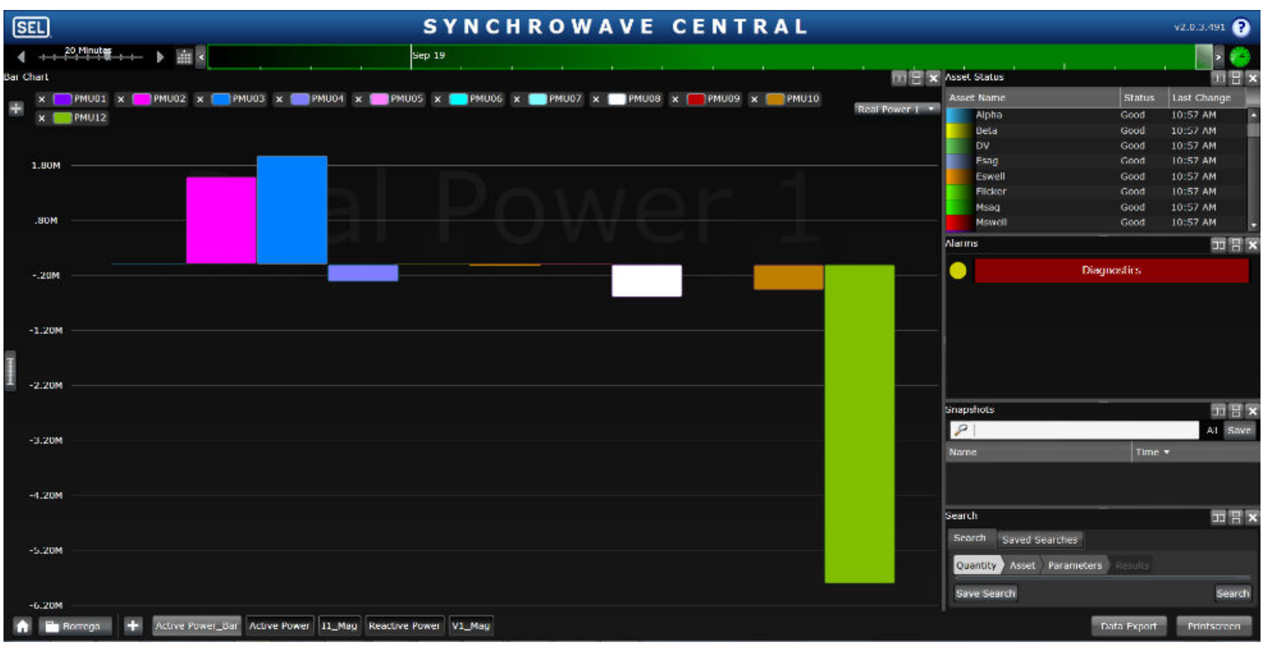


Figure 4-54. Active Powers of Different PMUs Subsequent to the Load Shedding

The following figures show the voltages, currents, real powers, and reactive powers of different PMUs during the load transfer test case. For transferring the load, the tie switch was closed first to establish the power flow. In the next step, the upstream recloser (on the second branch) was opened to reach a redial system configuration as expected by the operator.

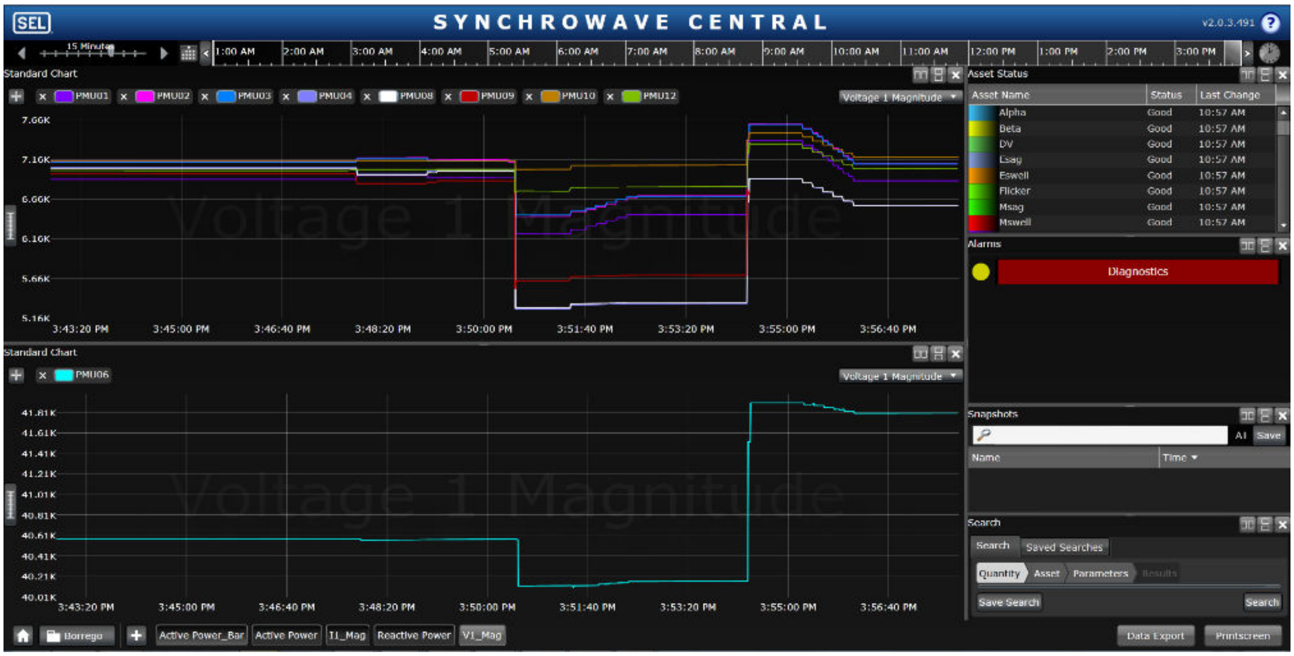


Figure 4-55. Magnitude of Positive Sequence Voltages, Capturing Exact Time of Load Transfer

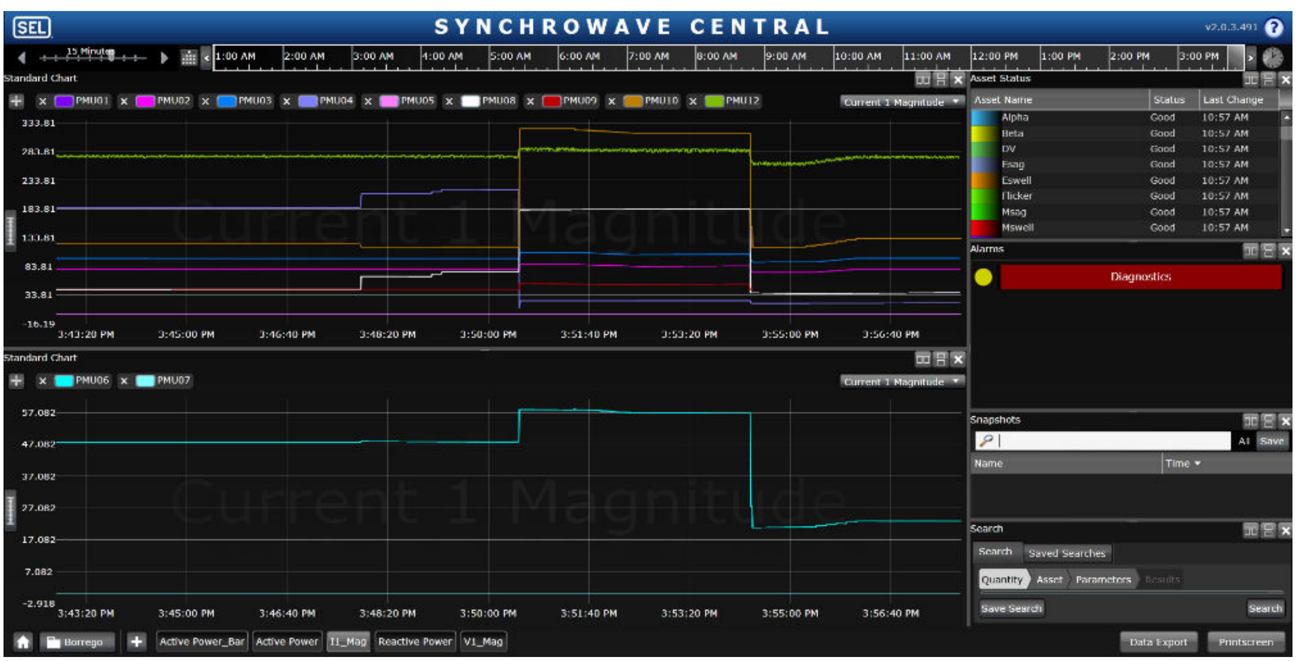


Figure 4-56. Magnitude of Positive Sequence Currents

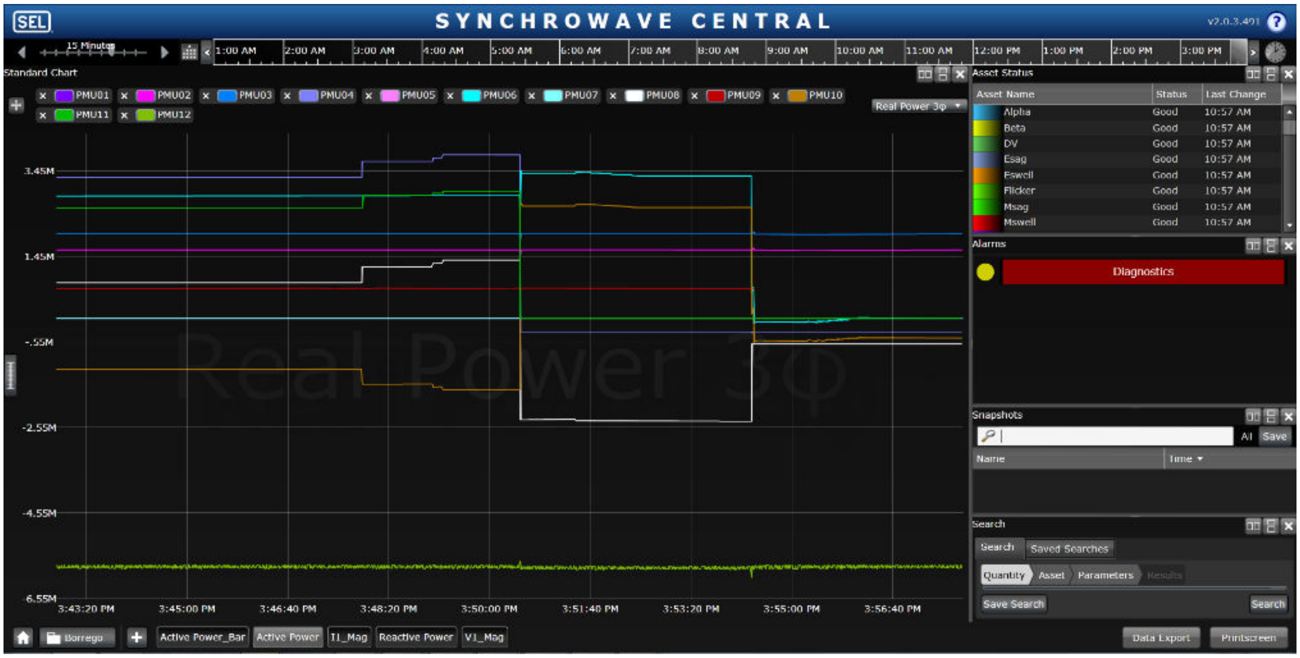


Figure 4-57. Active Powers

Change in both active and reactive power flow of the circuit that were captured by various PMUs across the circuit also demonstrated the disturbance caused by transferring load. In general, depending on the nature of a disturbance or an event, the impact can be observed by visualizing multiple system parameters.

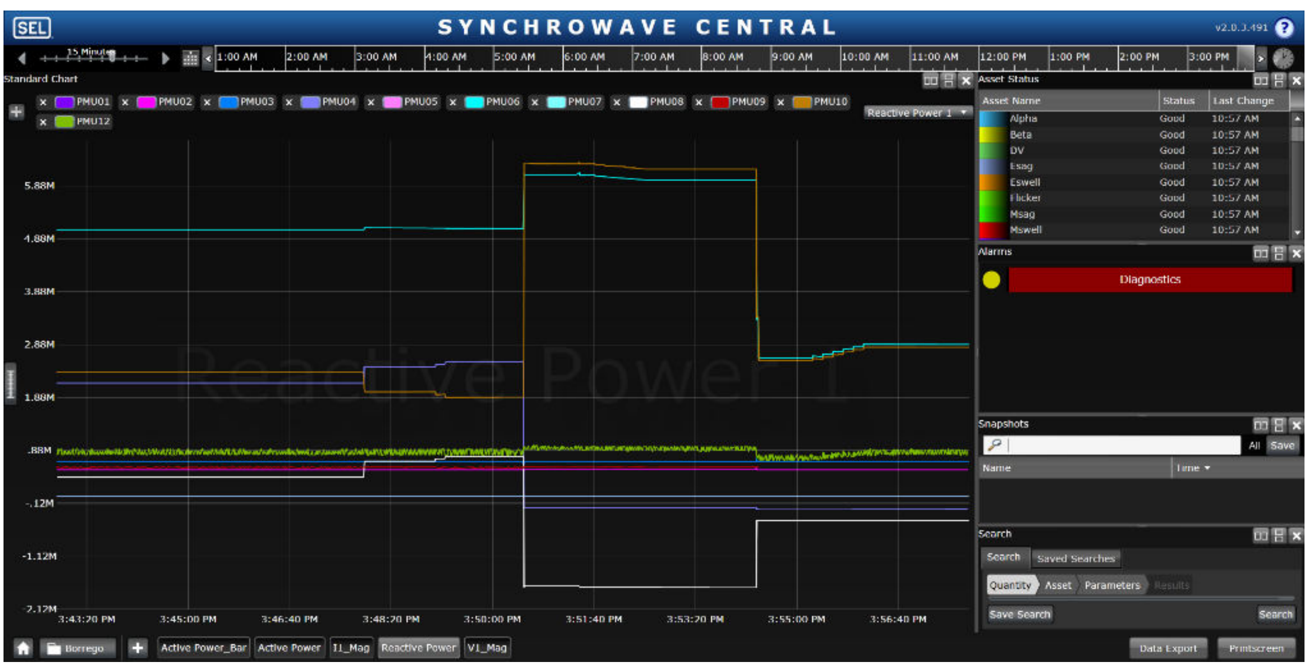


Figure 4-58. Reactive Powers

4.2.2.2 Intentional Islanding with 0.75 pu Loading Condition

In this case study, the loads were set at 0.75 pu and the PV was set at its maximum. The following figure shows the active power flow at different PMUs.

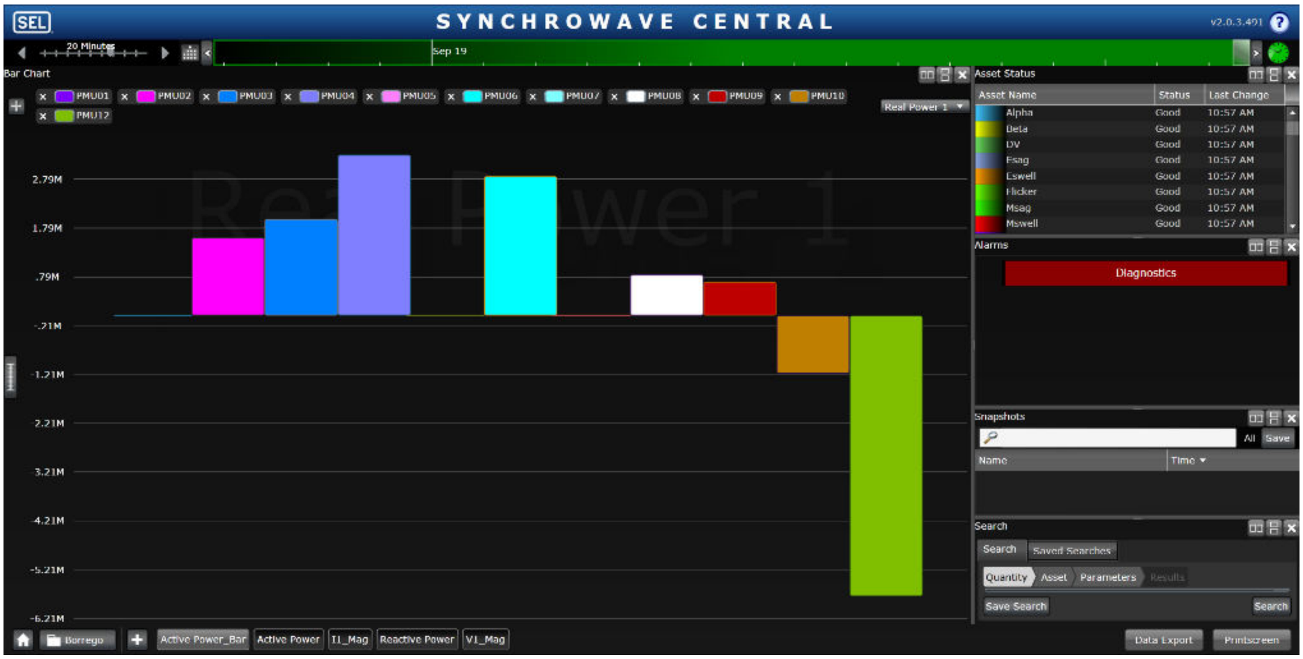


Figure 4-59. Active Powers of Different PMUs

Turning on the generators created reverse power flow in circuit 2 as shown in the following figure.

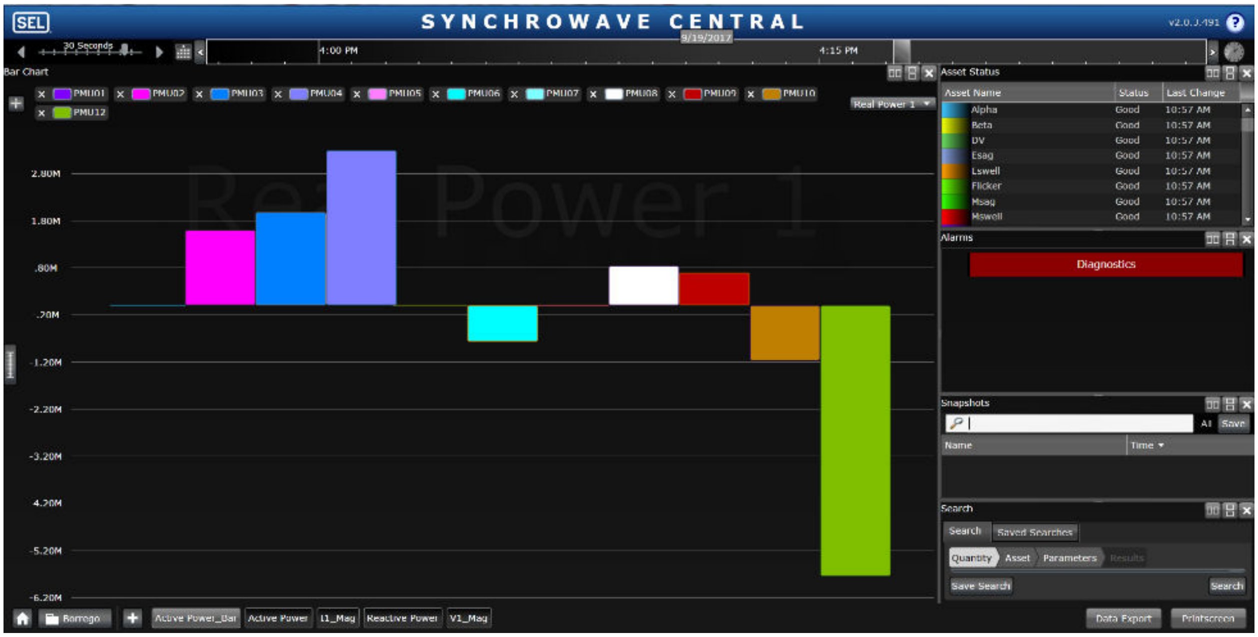


Figure 4-60. Active Powers of Different PMUs Subsequent to Turning on the Generators

Then, circuit 2 was islanded by opening CBC2. It can be observed that the system became unstable as shown in the following figure.

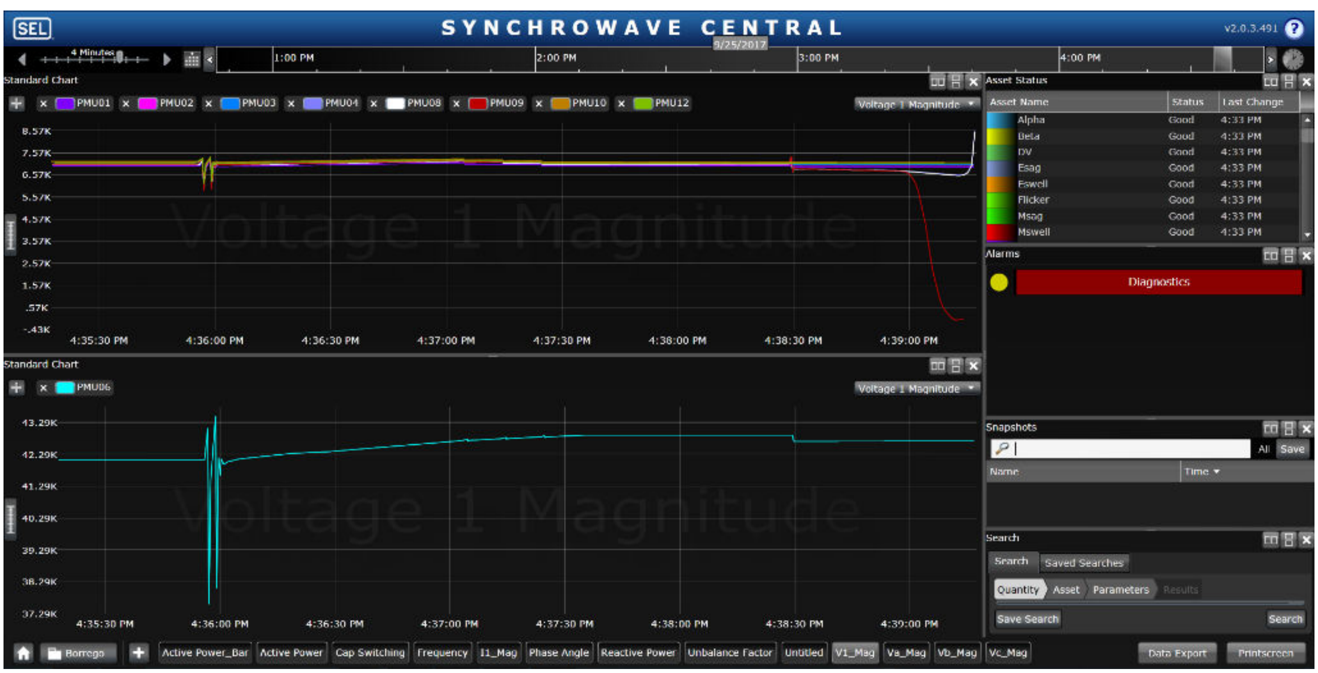


Figure 4-61. Magnitude of Positive Sequence Voltages during Islanding Process

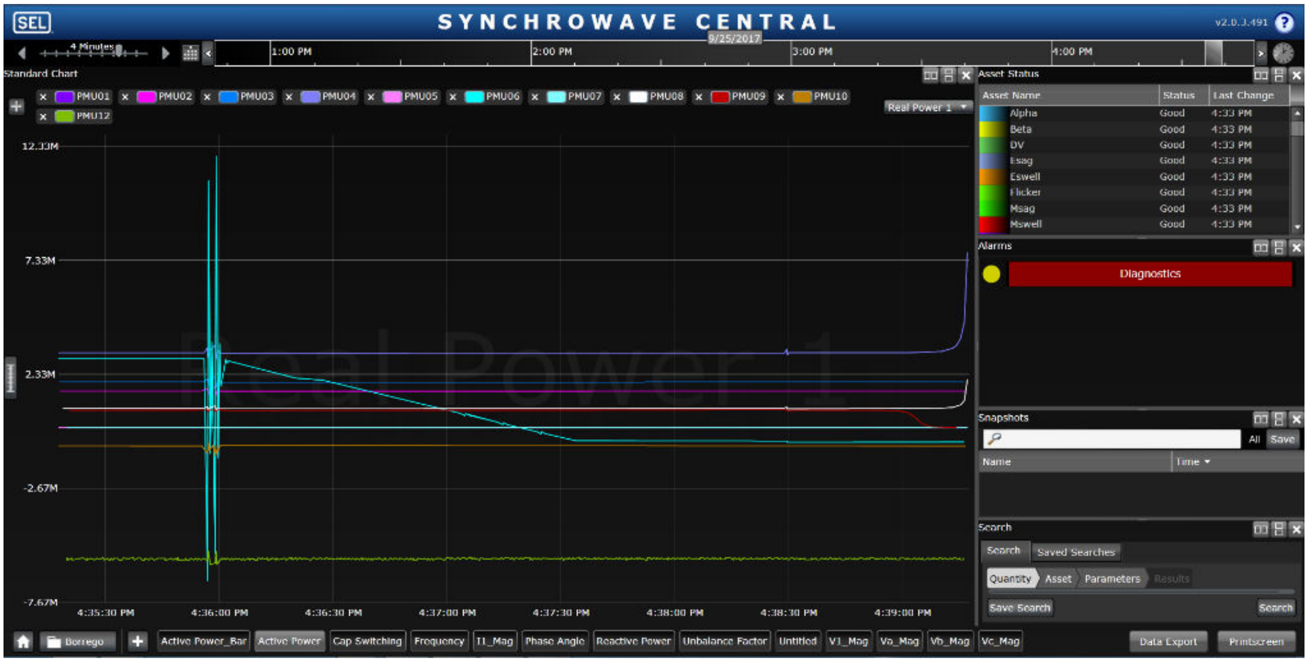


Figure 4-62. Active Powers during Islanding Process

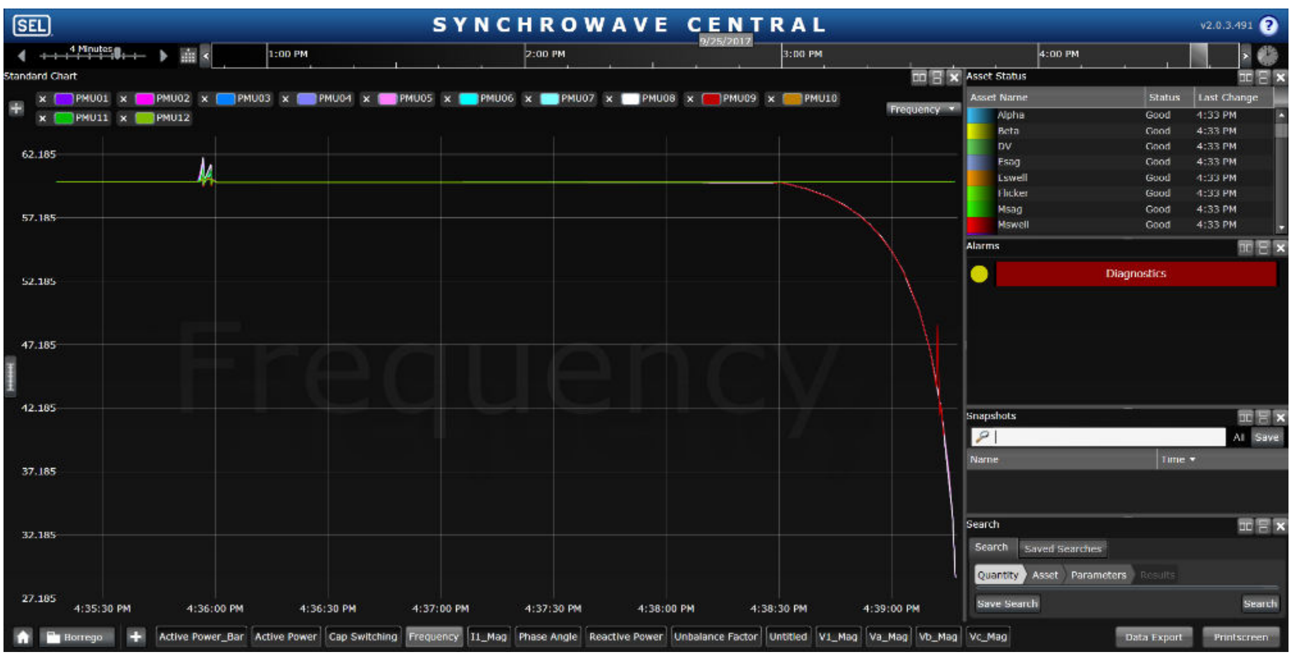


Figure 4-63. Frequency Changes during Islanding Process

Figure 4-64. Phase Angle Changes during Islanding Process

4.2.2.3 Intentional Islanding with 0.7 Loading Condition

In this case study, the loads were reduced to 0.7 pu. In this condition, the generation of the two generators are sufficient for the loads of the microgrid. The following figure shows the active power of different PMUs after turning on the generators.

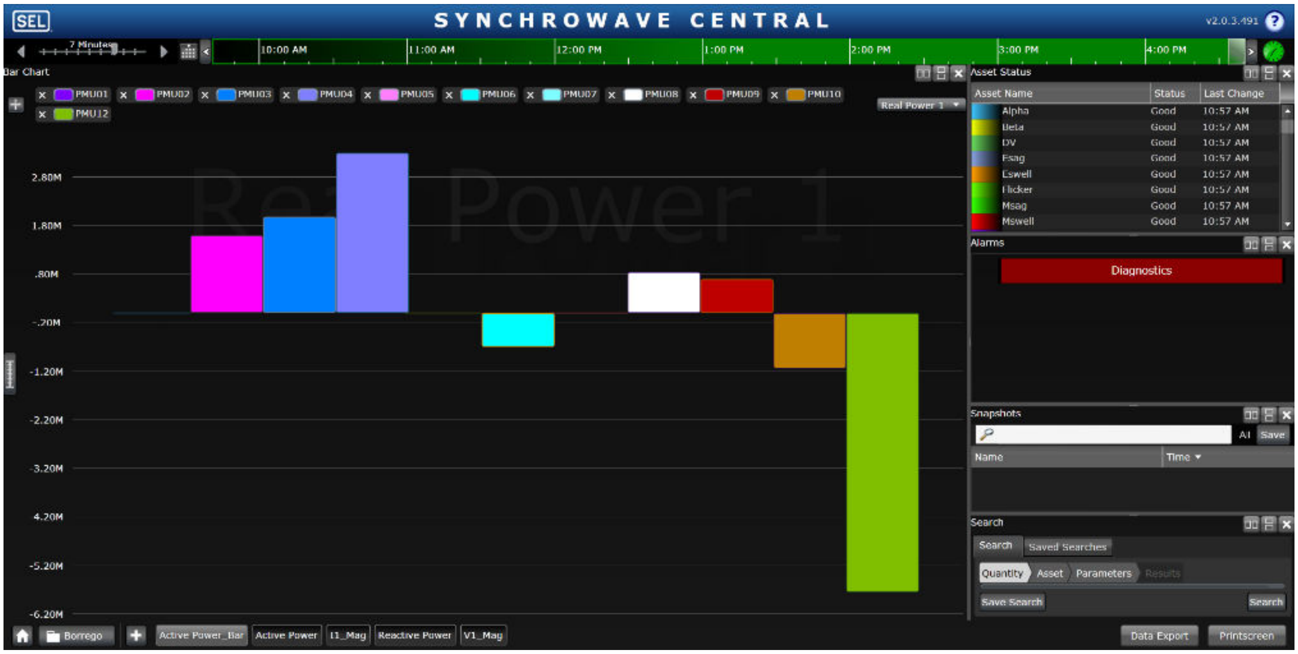


Figure 4-65. Active Powers of Different PMUs Subsequent to Turning on the Generators

In this case study, load shedding was performed before the islanding of circuits 3. Hence, the islanded circuit was stabilized based on available reserve capacity of the generation units under a reduced load condition.

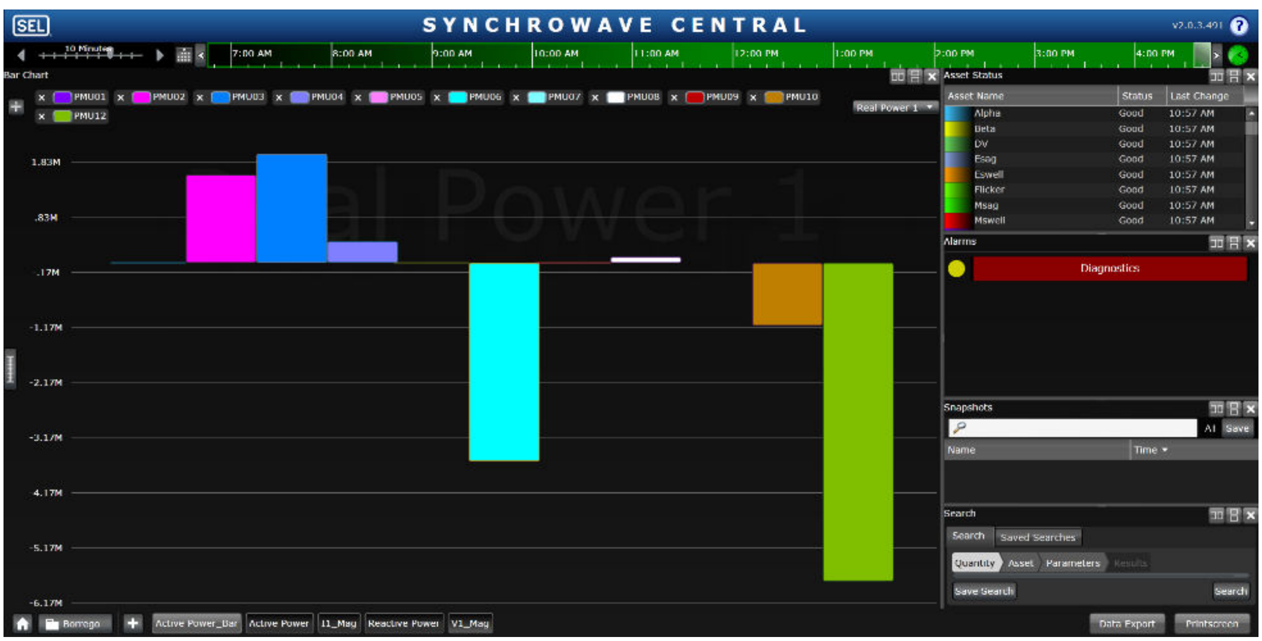


Figure 4-66. Active Powers of Different PMUs after Load Shedding

It can be observed that in this case study (unlike the case study with 0.75 loading condition), the islanded circuit was able to preserve its stability. The following figures show voltages, currents, active powers, and reactive powers of different PMUs during the islanding process.

Figure 4-67. Magnitude of the Positive Sequence Voltages

Voltage and power across the circuit were restored after a short period of transients.

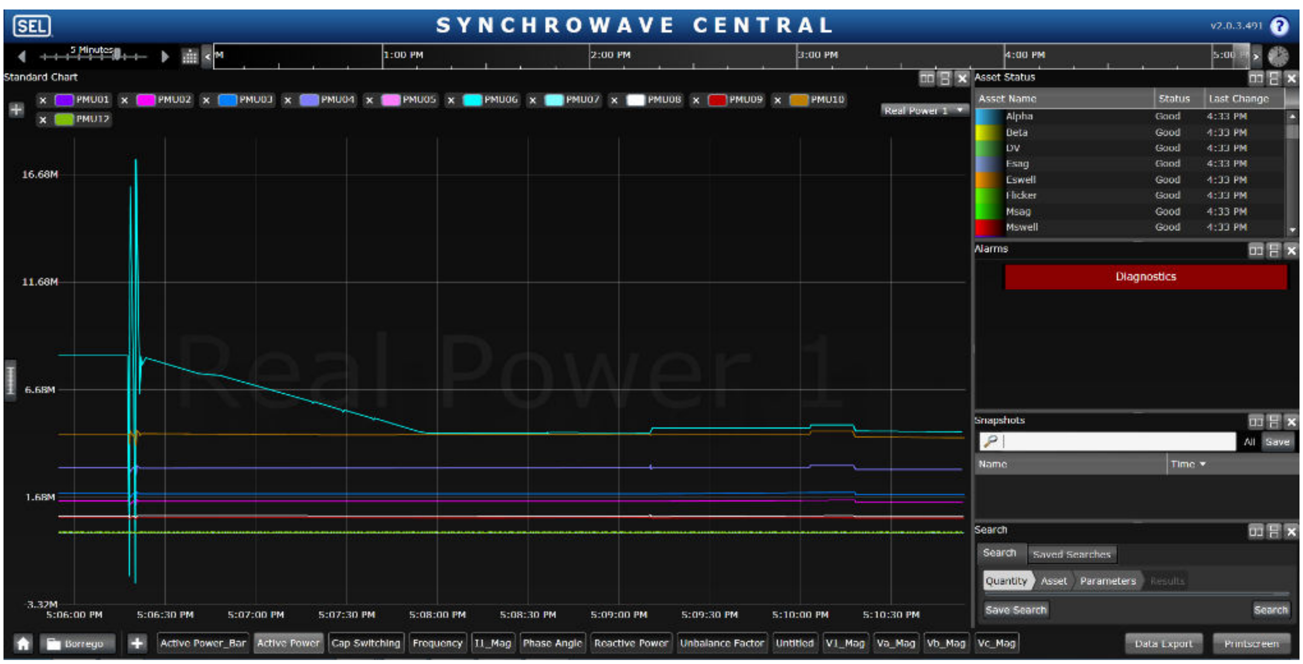


Figure 4-68. Active Powers

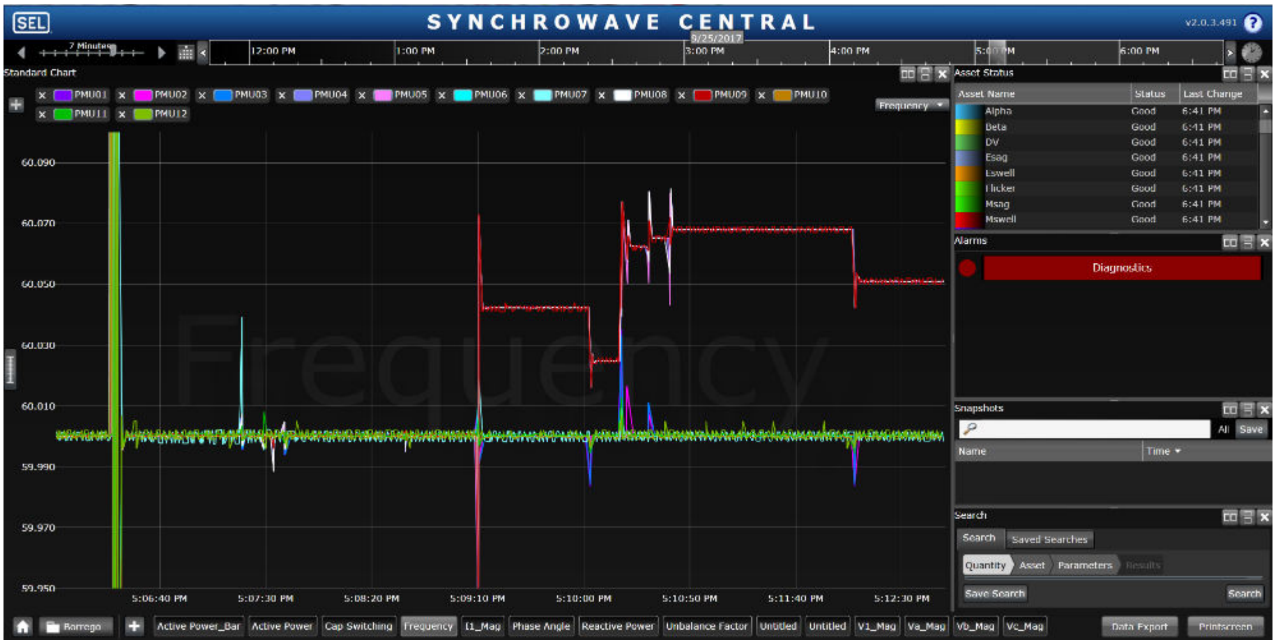


Figure 4-69. Reactive Powers

Because the frequency during island operation is not 60 Hz, the phase angle of the phasor measurement shows an oscillatory behavior. Most PMU devices are very sensitive to frequency changes (such as the case of islanding) can only tolerate a small deviation in power frequency from 60 Hz.

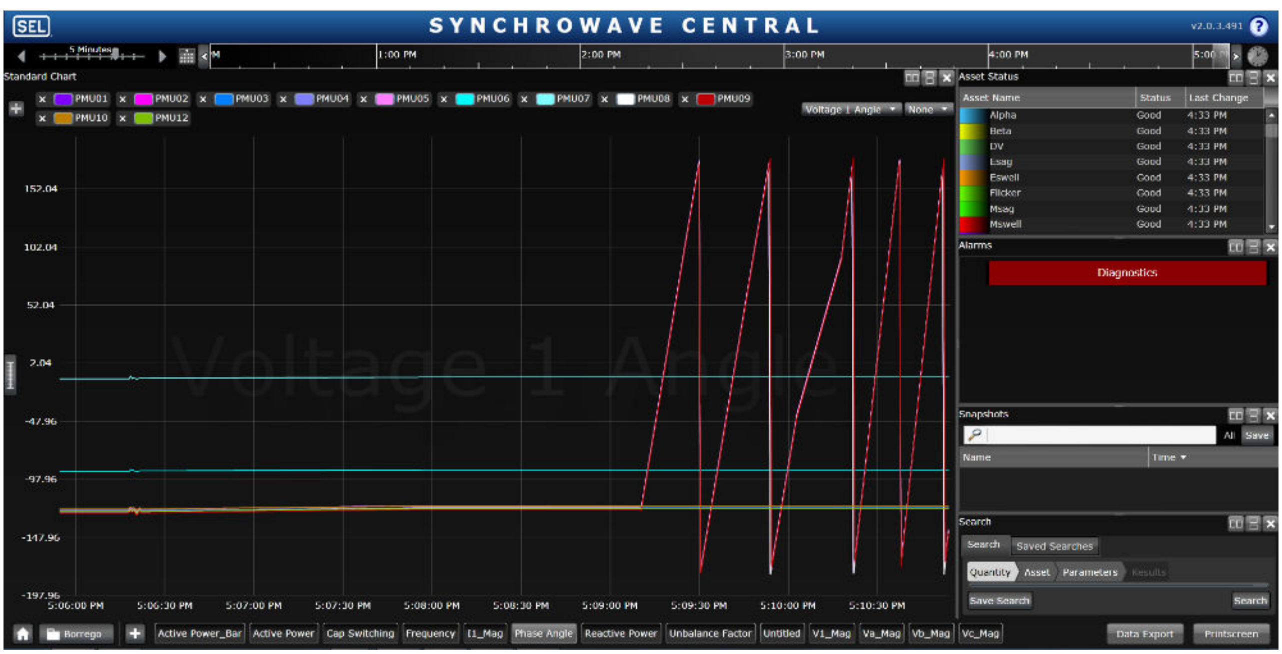


Figure 4-70. Phase Angle Changes during Islanding Process

4.2.2.4 Unbalance Factor

Loads were set to 0.75 pu and PV was set to its maximum value (6MW). In this case study, severe unbalanced condition caused by the malfunction of a circuit breaker was applied to the circuit to investigate its effect across the circuit. For this purpose in the first case study, phase A of the CB171 was opened. Figure 4-71 shows that this action caused a huge voltage variation in the downstream PMUs (PMU 12, PMU 1, PMU 2, and PMU3), while it did not creat a tangible positive voltage change in the upstream PMUs.

This malfunction can be identified more easily (even in the upstream PMUs or even Circuit 2 PMUs) by monitoring the unbalanced factor as shown in Figure 4-72. It can be seen that all PMUs have higher unbalanced factor than the threshold (0.3%).

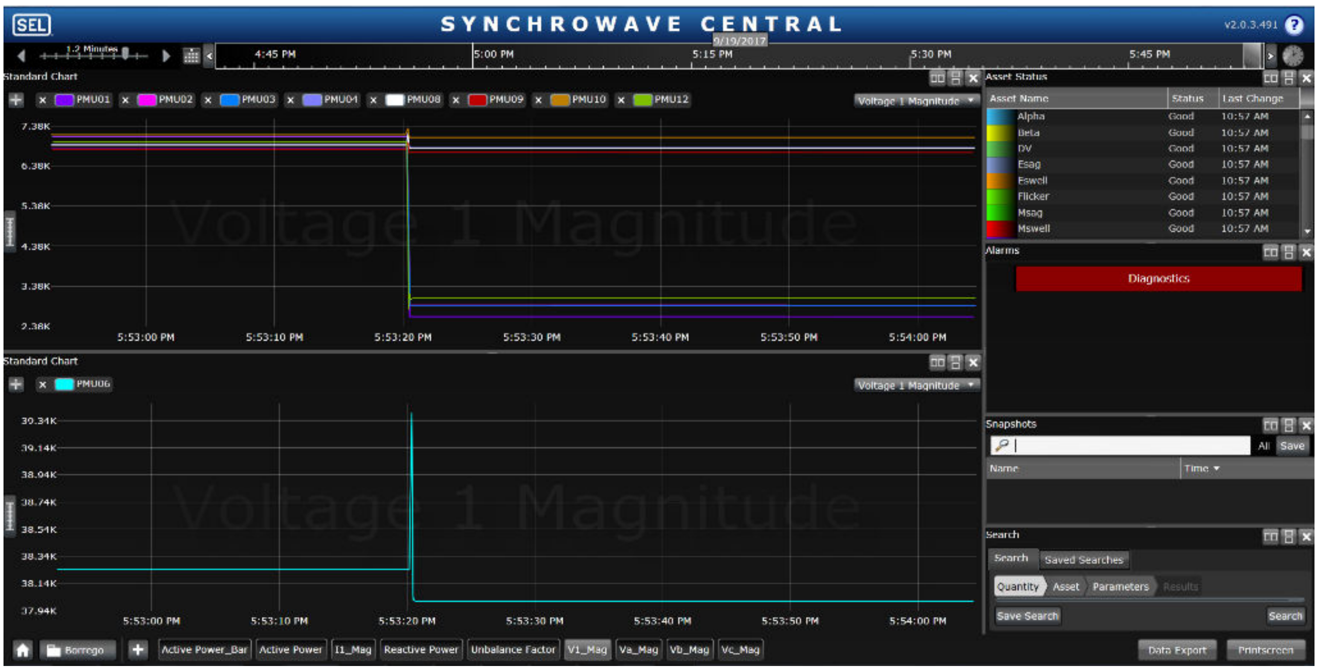


Figure 4-71. Magnitude of the Positive Sequence Voltages

Figure 4-72. Unbalanced Factors

The similar malfunction was applied to recloser CB171567. The magnitude of the positive sequence voltage is shown in Figure 4-73. It can be seen that, except PMU 2 in the downstream of CB171567, this malfunction cannot be detected by observing positive sequence voltage. However, it can be detected from the unbalanced factor of all PMUs as shown in Figure 4-74.

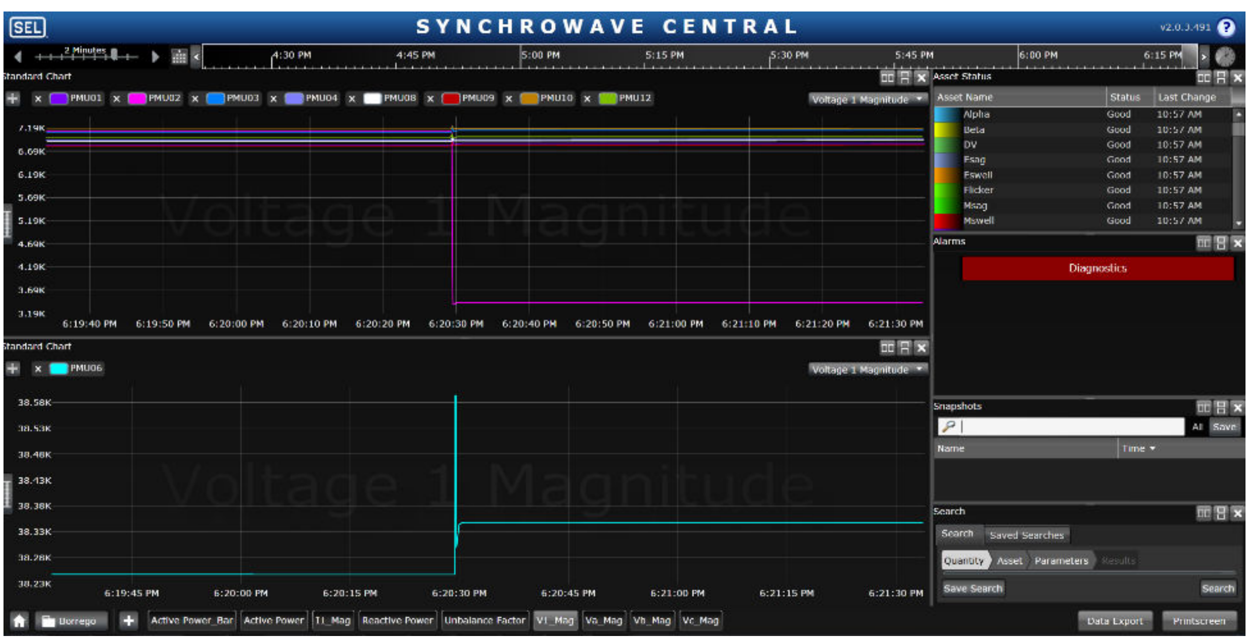


Figure 4-73. Magnitude of Positive Sequence Voltages

Figure 4-74. Unbalance Factors

4.2.2.5 Fault

In this case study, a single line to ground fault was applied for 20 ms to the downstream of the VR2. Voltage, current, real power, and reactive power of different PMUs are shown in the following figures.

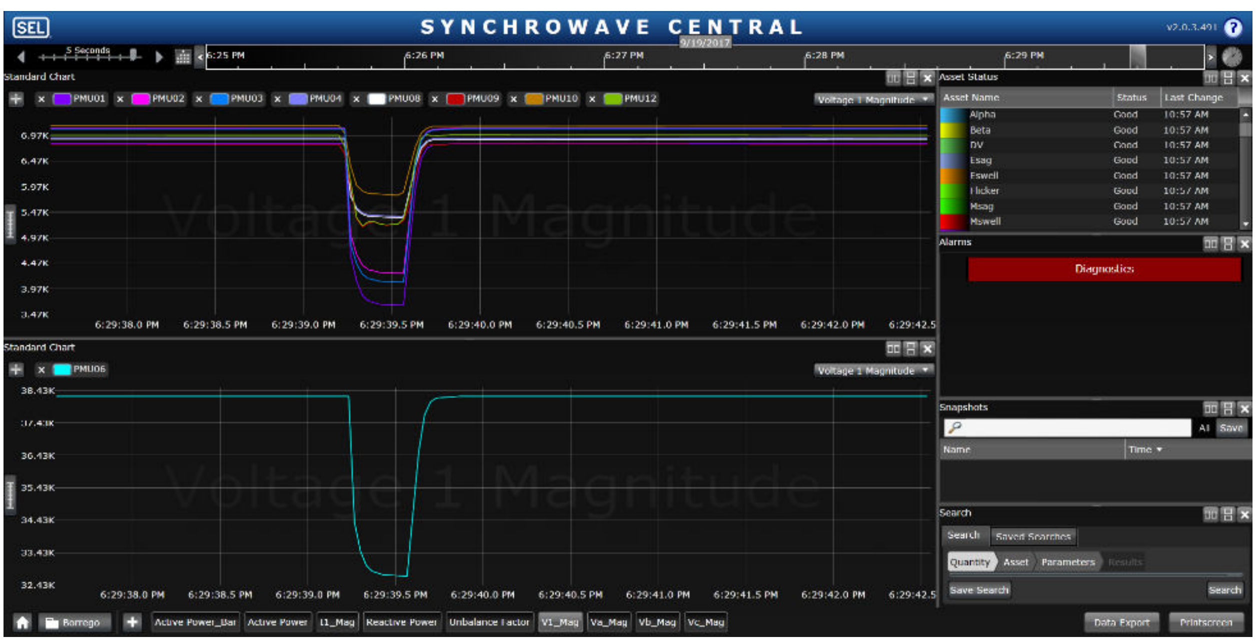


Figure 4-75. Magnitude of Positive Sequence Voltages

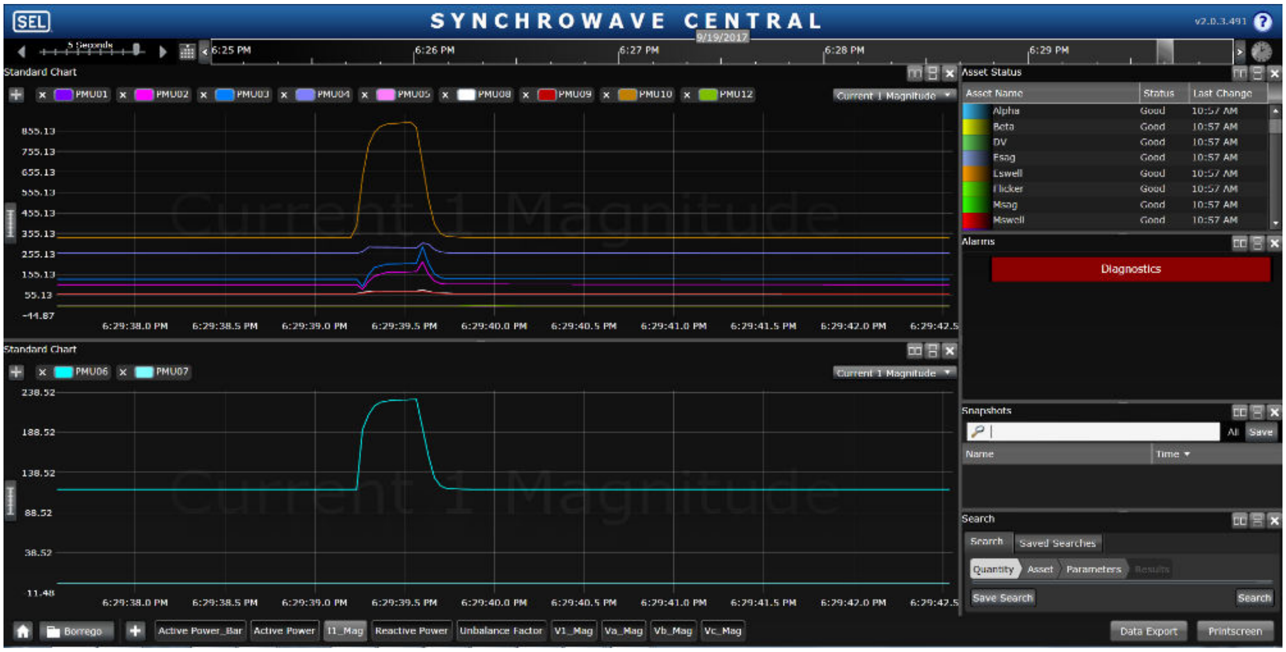


Figure 4-76. Magnitude of Positive Sequence Currents

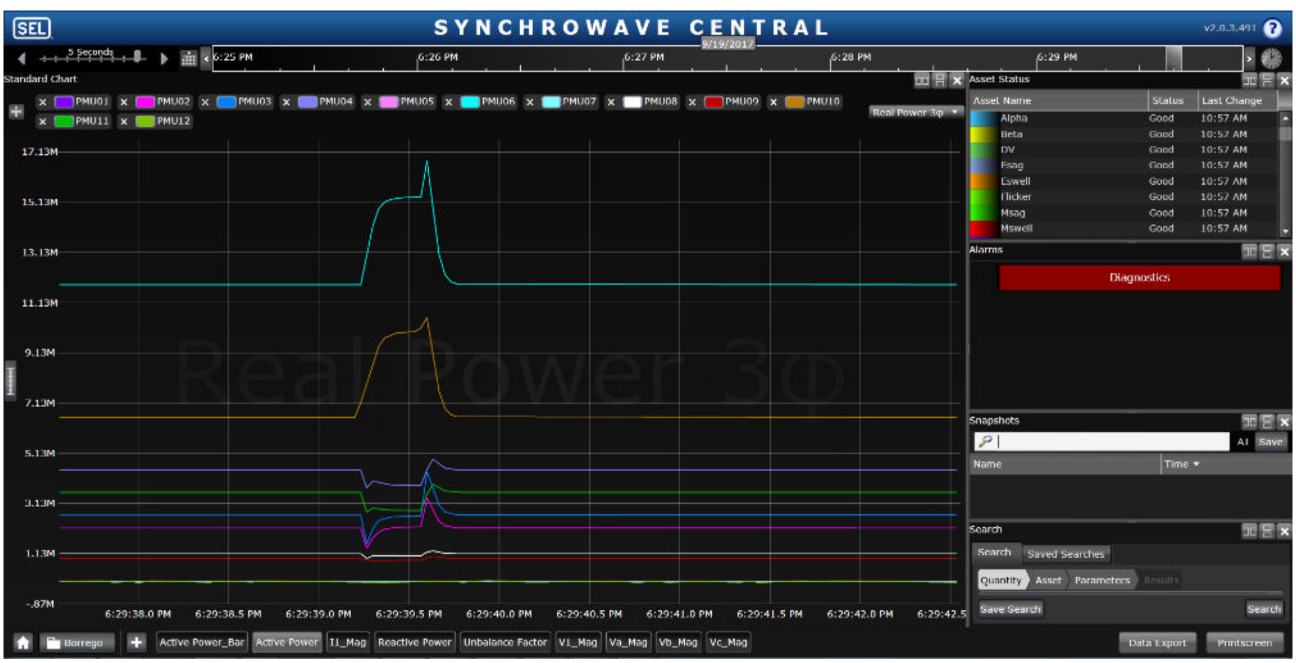


Figure 4-77. Active Powers

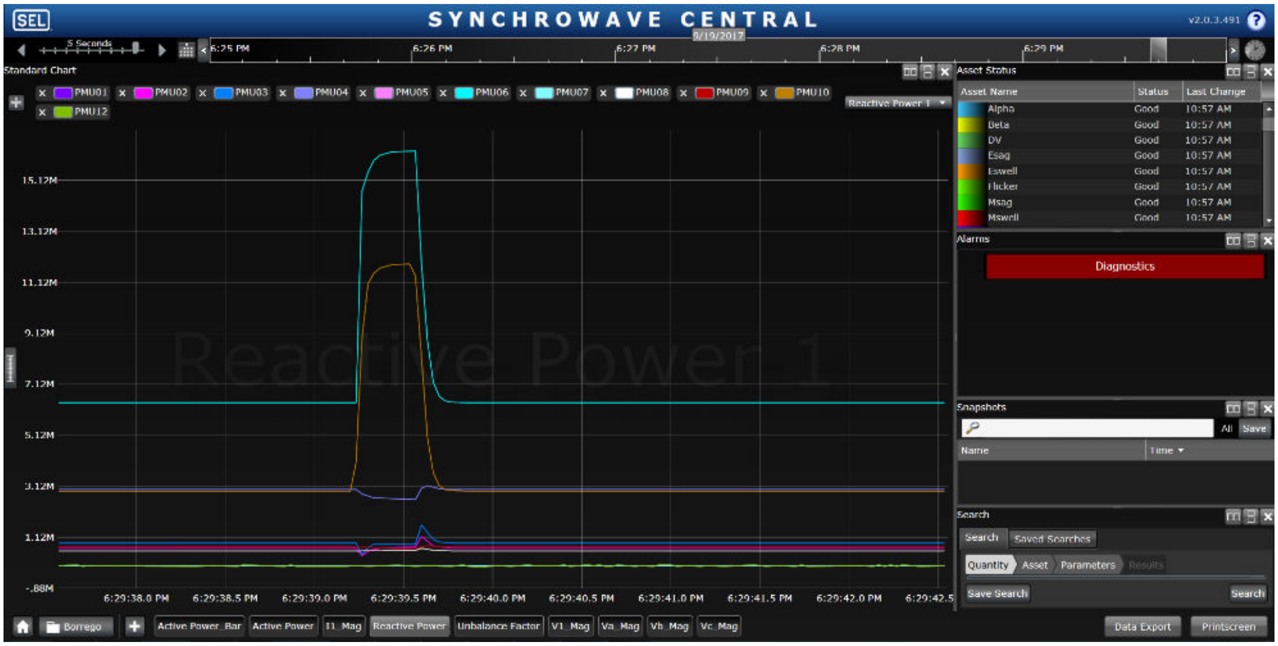


Figure 4-78. Reactive Powers

4.2.2.6 Capacitor Switching

In this section, the capacitor switching in Circuit 2 and Circuit 3 is investigated in two separate test cases.

In the first test case, the capacitor switching in circuit 3 is studied. Initially, CBC372 and CBC198 were open. The sequence of actions and the real/reactive power of the circuit breaker CB171 are summarized in the following table.

Switch Status	Real Power (MW)	Reactive Power (MVAr)
Open CBC372 / Open CBC198	6.758	2.210
Close CBC372 / Close CBC198	6.773	-0.050
Open CBC372 / Closed CBC198	6.750	1.050
Closed CBC372 / Open CBC198	6.763	1.101
Open CBC372 / Open CBC198	6.756	2.210

The following figures show voltage and real power of different PMUs. It can be seen in Figure 4-80 that when both of the capacitors were switched on, the losses in the circuit 3 was maximum.

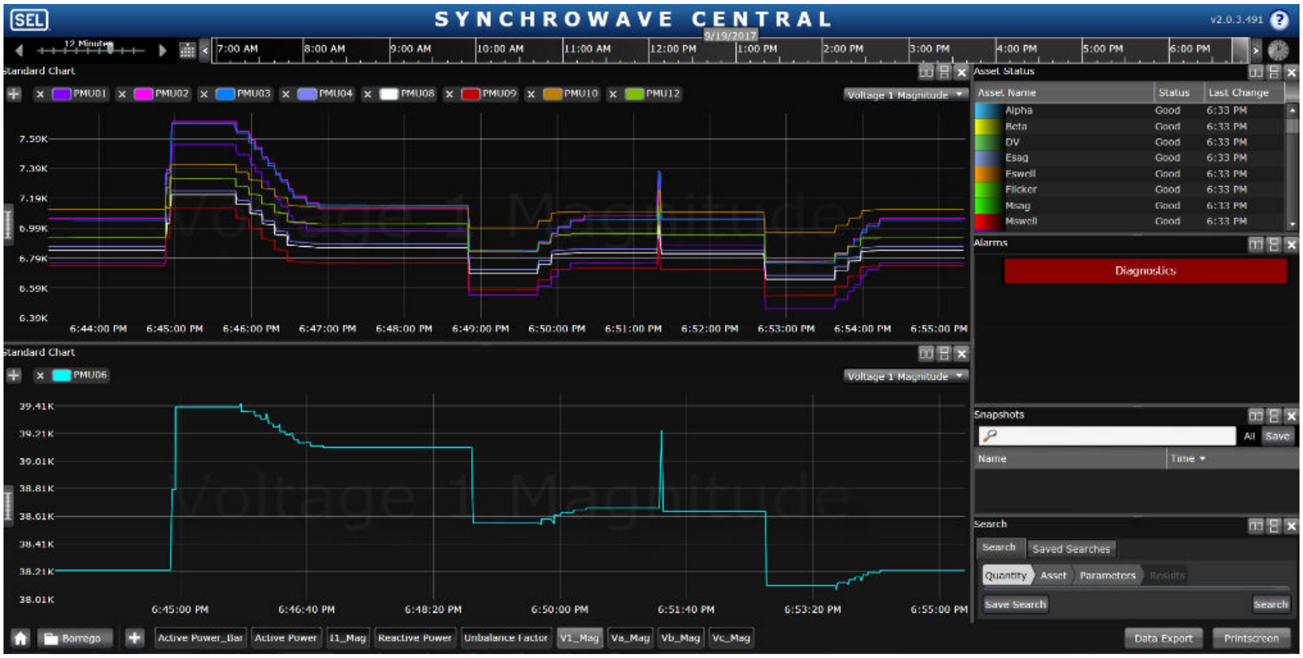


Figure 4-79. Magnitude of Positive Sequence Voltages

The step changes in voltages caused by variations in tap positions are clearly observable from the results.

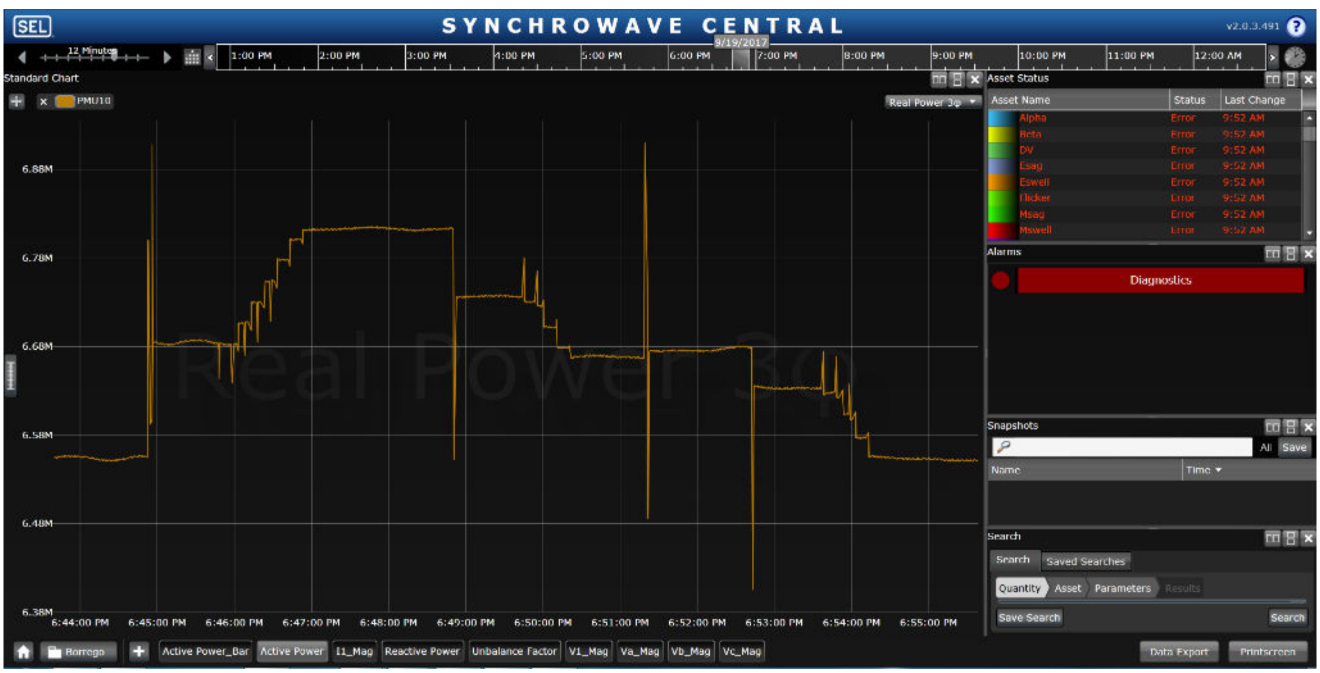


Figure 4-80. Real Power of PMU 10

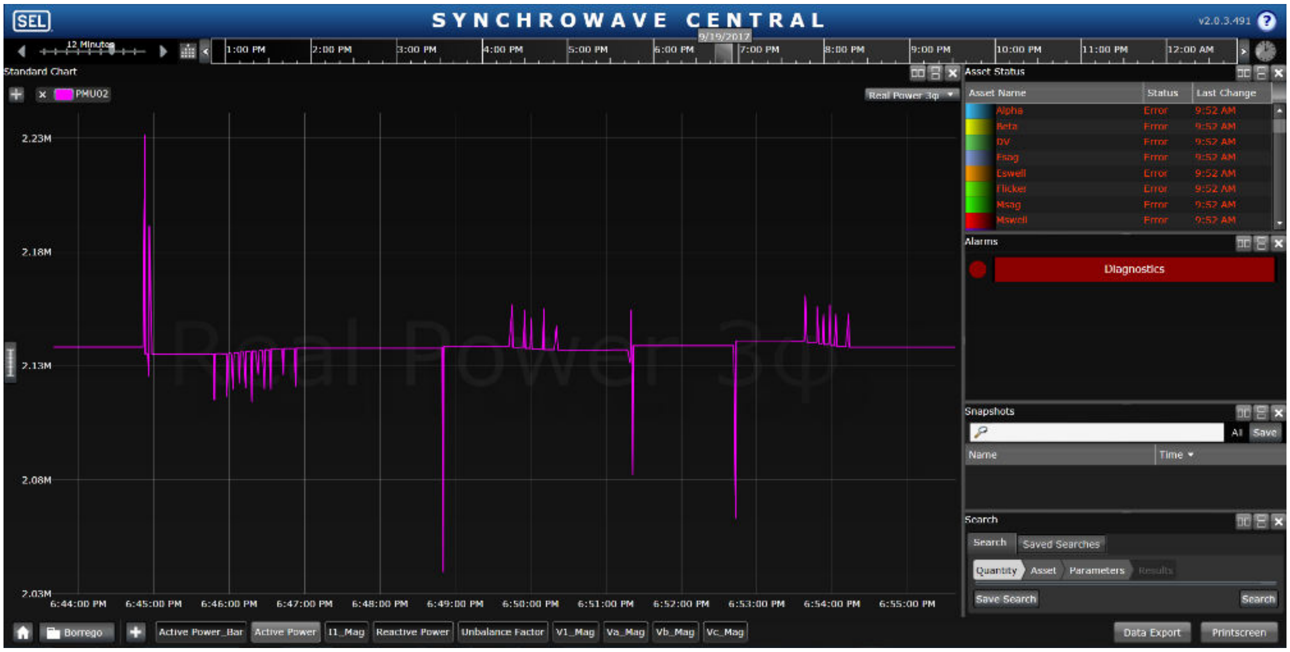


Figure 4-81. Real Power of PMU 2

Although the tap position changes are observable in the real power screen, power flow screens are not generally the best visualization screen for detecting and analyzing these events, since the impact is on voltages.

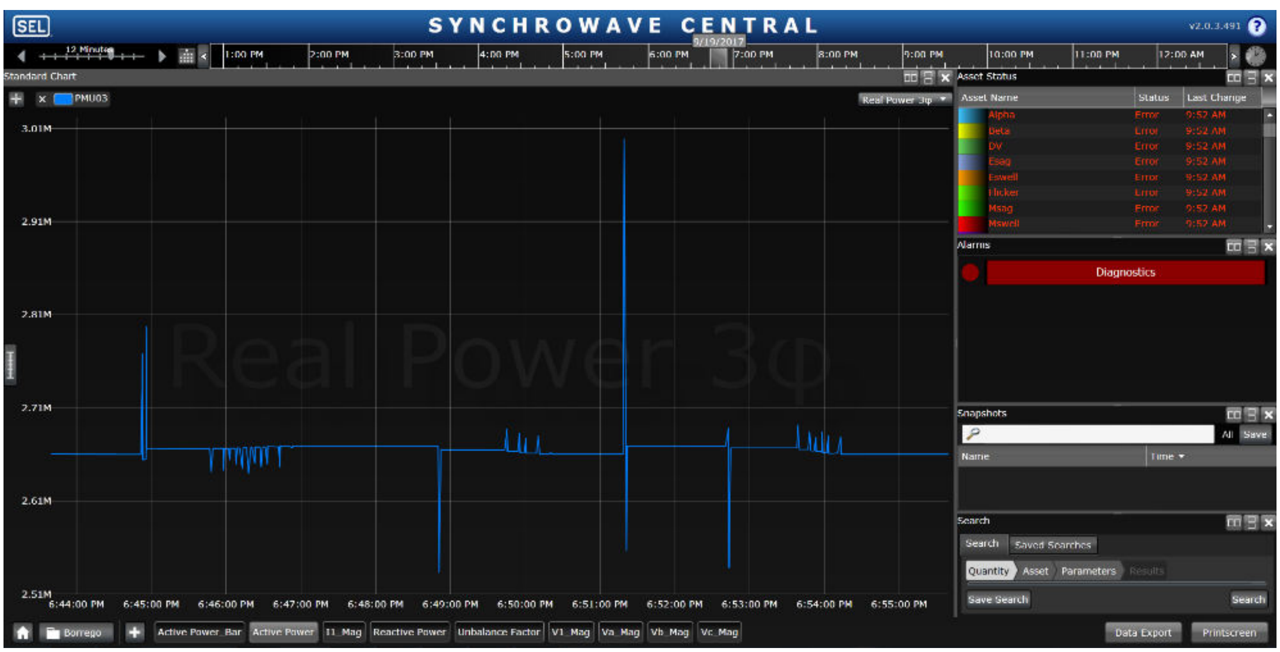


Figure 4-82. Real Power of PMU 3

A similar case study was performed for circuit 2. Initially, CBC393 and CBC17016 were open. The sequence of actions and the real/reactive power of the circuit breaker are summarized in the following table.

Switch Status	Real Power (MW)	Reactive Power (MVAr)
Open CBC393 / Open CBC17016	4.974	3.392
Open CBC393 / Close CBC17016	4.827	2.215
Close CBC393 / Close CBC 17016	4.806	1.004
Close CBC393 / Open CBC 17016	4.856	2.135
Open CBC393 / Open CBC17016	4.984	3.405

The following figures show voltages and real powers of different PMUs. It can be seen in Figure 4-84 that when both of the capacitors were switched on, the losses in the circuit 3 was minimum.

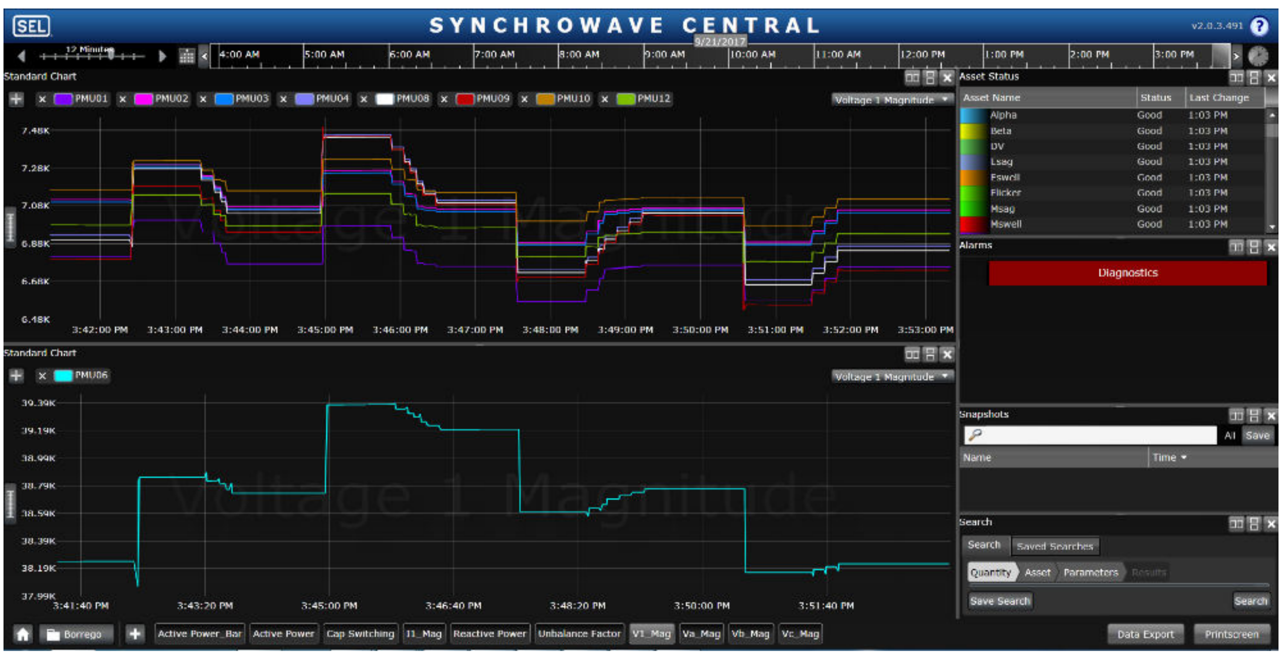


Figure 4-83. Magnitude of the Positive Sequence Voltages

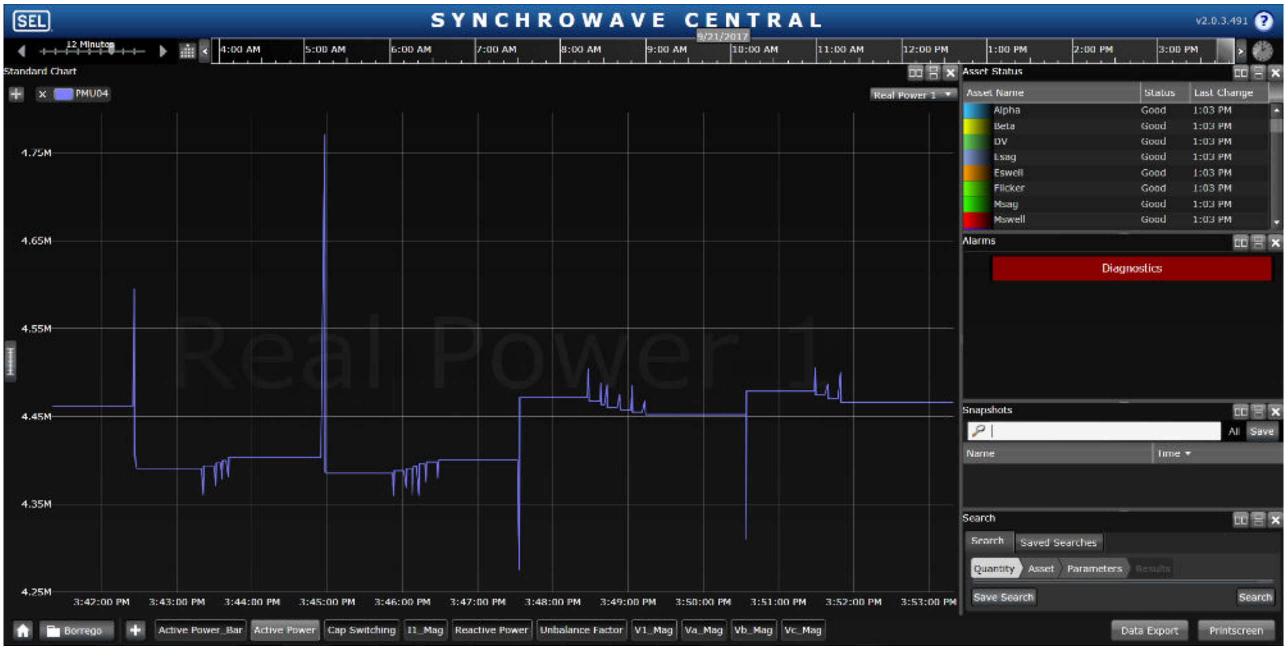


Figure 4-84. Real Powers of PMU 4

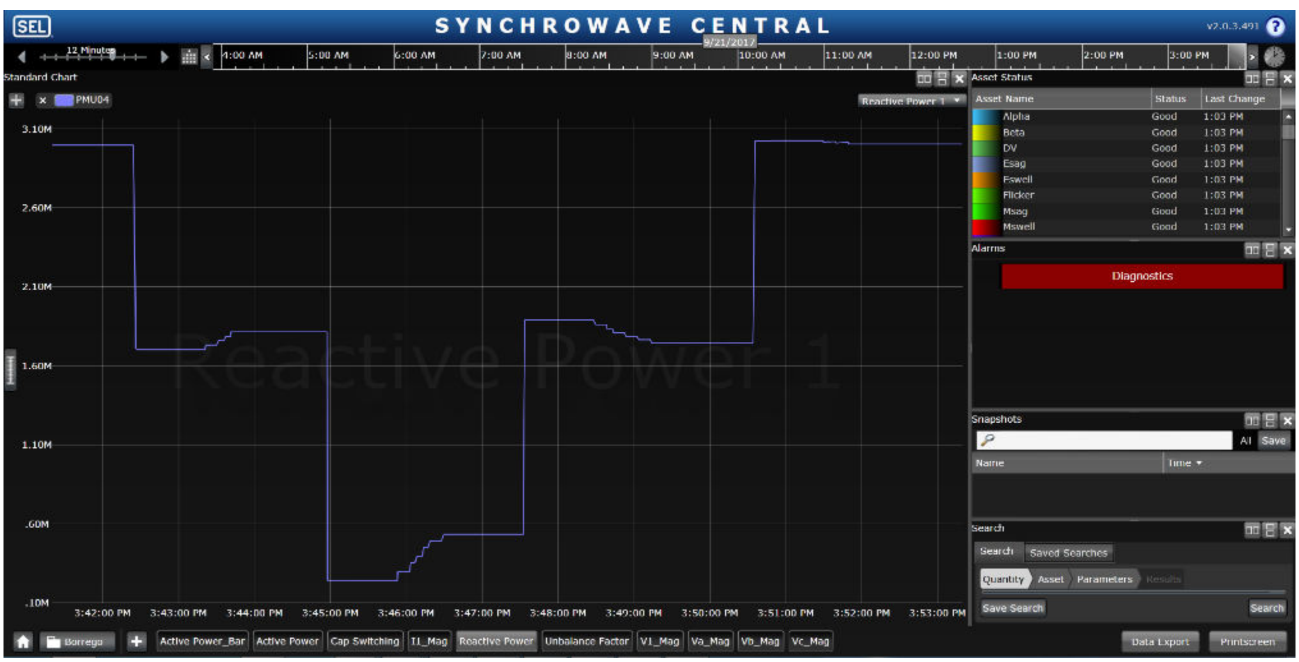


Figure 4-85. Reactive Powers of PMU 4

4.3 Use Case 6 (Circuit 4) – Water Treatment Facility Monitoring and Reactive Power Management

Following figure shows circuit 4 topology and location of the Water treatment plants (WTPs), line monitors (LMs) and switched capacitors. Due to the unavailability of the data for this circuit, one of the branches of the circuit 1 with PV is modified such that have similar behavior to the circuit 4 west branch.

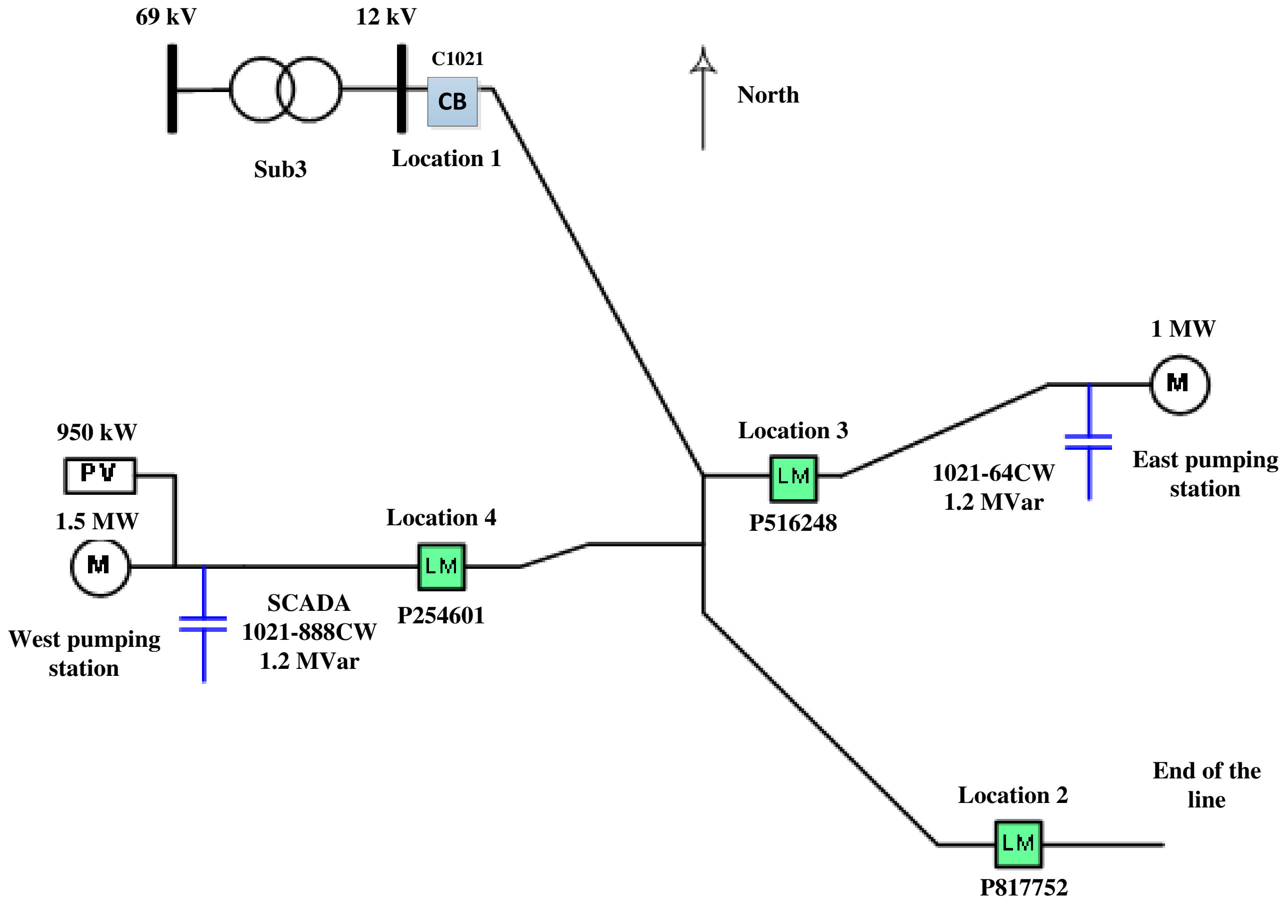


Figure 4-86. Circuit 4 Topology and Location of Line Monitoring (LM) Devices

The main objective of this use case is to coordinate and mange operation of large/critical industrial facilities such as Water Treatment Plants with the grid. The key operation aspects from the grid point of view are Real and Reactive power consumption. Specifically, for the reactive power management, the main value-added feature and advantage offered by the use case will be coordination of reactive power requirements from the plant with operation of shunt capacitors on the associated circuit feeding the plant.

The high-level sequence diagram for reactive power management application has been depicted Figure 4-87. The main approach is to observe the reactive power flow of the line through the PMU and switch in/out the capacitor banks (with a 15-second delay).

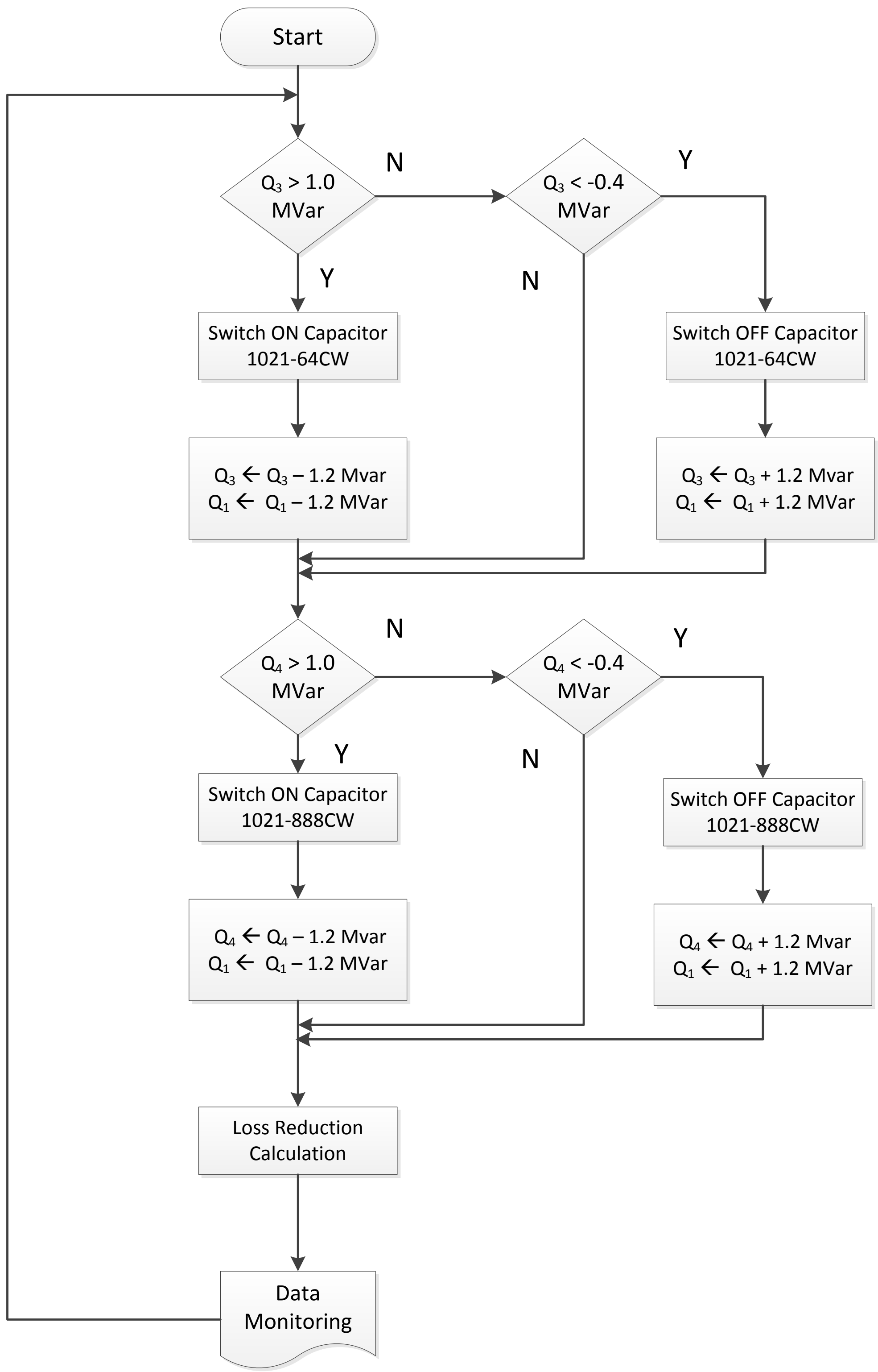

Start
$Q_3 > 1.0$ MVar
N
Y
$Q_3 < -0.4$ MVar
Y
N
Switch ON Capacitor 1021-64CW
Switch OFF Capacitor 1021-64CW
$Q_3 \leftarrow Q_3 - 1.2$ Mvar
$Q_1 \leftarrow Q_1 - 1.2$ MVar
$Q_3 \leftarrow Q_3 + 1.2$ Mvar
$Q_1 \leftarrow Q_1 + 1.2$ MVar
$Q_4 > 1.0$ MVar
N
Y
$Q_4 < -0.4$ MVar
Y
N
Switch ON Capacitor 1021-888CW
Switch OFF Capacitor 1021-888CW
$Q_4 \leftarrow Q_4 - 1.2$ Mvar
$Q_1 \leftarrow Q_1 - 1.2$ MVar
$Q_4 \leftarrow Q_4 + 1.2$ Mvar
$Q_1 \leftarrow Q_1 + 1.2$ MVar
Loss Reduction Calculation
Data Monitoring

Figure 4-87. A High-level Sequence Diagram for Reactive Power Management

4.3.2.1 Reactive Power Management without PV

For this test, initially, the load was 0.3 MW with the power factor of 0.8. Load was increased to 1.5 MW for 2 minutes and decreased back to 0.3 MW. The following figure shows voltage, active power, reactive power, and the loss of the line. It can be seen that when the load is increased, the reactive power observed by the PMU increased to 1.14 MW which is higher than the threshold; therefore, due to the defined logic, the capacitor turned on automatically after 15 seconds. Switching on the capacitor decreased the line loss by locally compensating the reactive power requirements.

Similarly, reactive power decreased to -1.3 MW after the load decreased to 0.3 MW. Because of the defined logic, the capacitor turned off automatically after 15 seconds. In this case, switching off the capacitor decreased the line loss to avoid overcompensation of the circuit.

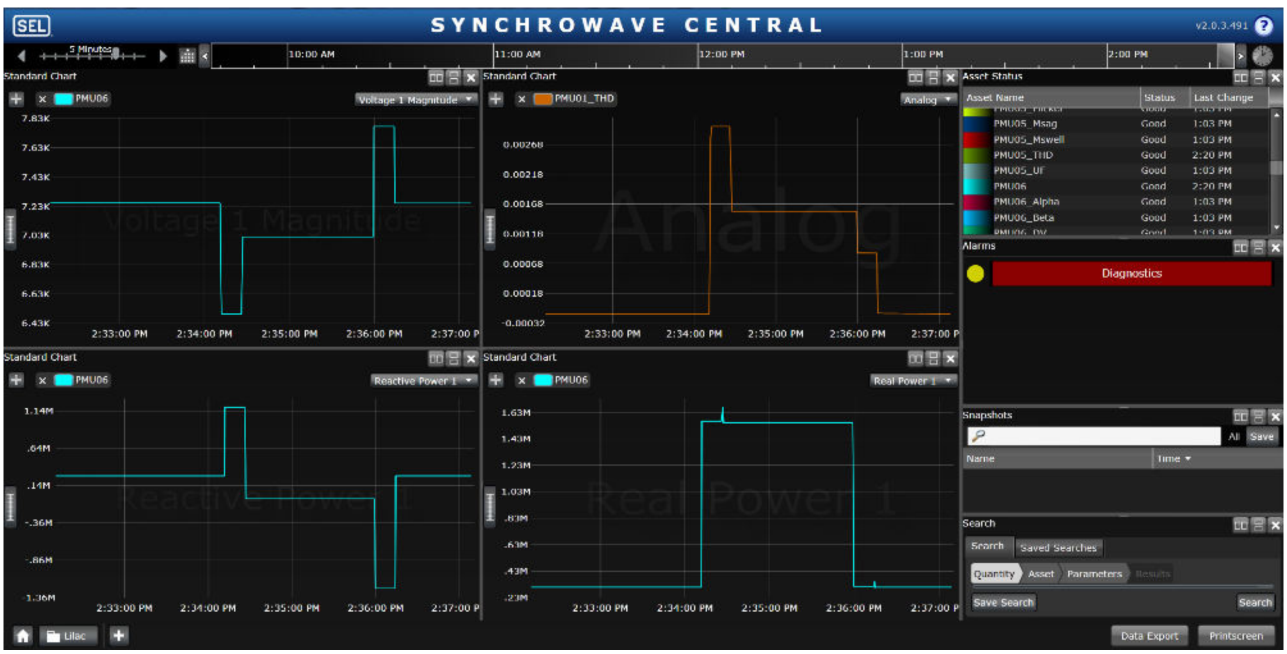


Figure 4-88. Voltage, Line Loss, Reactive Power, and Real Power

4.3.2.2 Reactive Power Management with PV

A similar test case was repeated with injecting 1 MW PV. It was observed from the following figure that the reactive power management along with local generation (PV) minimizes the line loss and improve the voltage profile. The test case confirms the effectiveness of the hybrid approach by utilizing both active and reactive power management of the customer load locally.

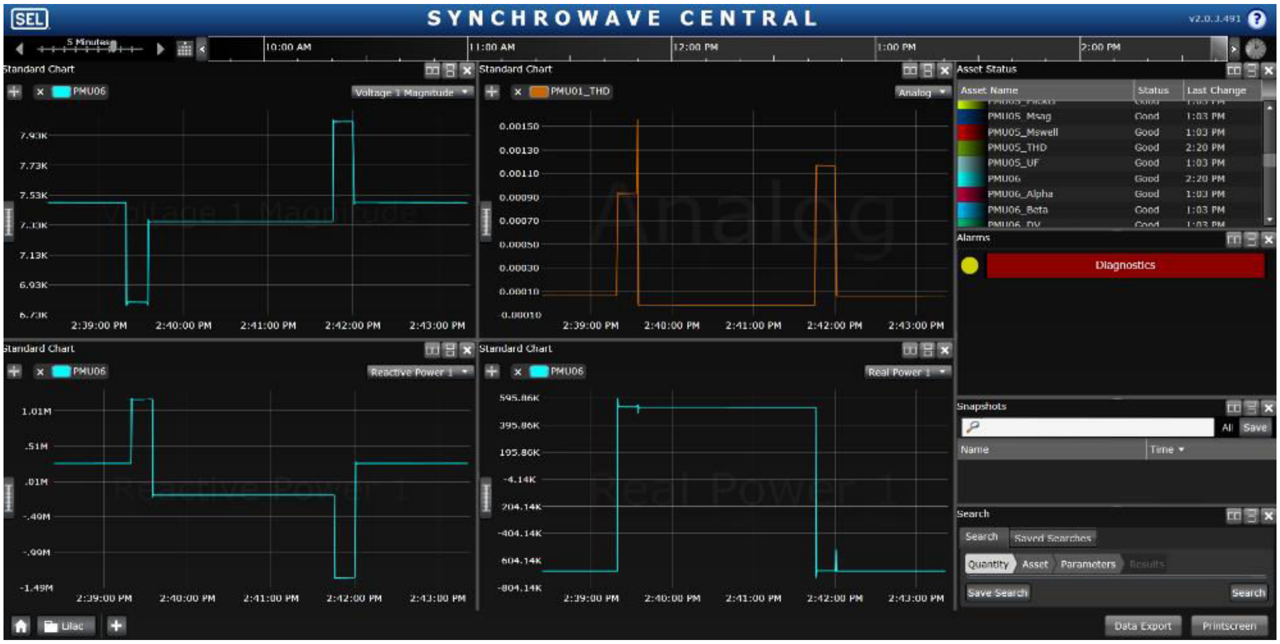


Figure 4-89. Voltage, Line Loss, Reactive Power, and Real Power

In general, the visualization screens were effective in detecting and analyzing various system disturbances. As observed, each screen and measured parameters or indices are primarily tailored for specific event detections and analysis. The combination of the proposed visualization screens and associated KPIs are needed to properly perform root-cause analysis.

5 Conclusions and Findings

This section provides a summary of key observations and conclusions from performing the pre-commercial demonstration of the monitoring and visualization technology, as well as analysis of the results and findings about the technology implementation and opportunities for system operation improvements.

5.1 Conclusions and Findings Related to Assessment of Integration and Monitoring Tools

5.1.1 Monitoring approaches

This project demonstrated new technologies and analysis methods for monitoring, visualization, and root-cause analysis of distribution systems by using various measurement techniques, data sources and integrating them in one platform to provide a unique monitoring and visualization user experience. In the advent of new customer technologies integrating with the utility systems, the proposed platform provides unique set of tools for distribution system operators and engineering analysis groups to monitor dynamic events, especially ones caused by varying characteristics of DER productions, loading effect of electric vehicle charging stations, and power electronic apparatus.

The novel concept of proposed visualization system is the ability of integration and utilization of multiple measurement platforms in one operation screen to achieve interoperability among various measurement tools and data format already exist for monitoring of customer systems and distribution systems. The key capabilities demonstrated included:

- Being able to monitor distribution assets in real-time, based on measurements received from PMUs, AMI system, Power Quality measurement devices, and SCADA system.
- Being able to tap onto historical data collected to playback and investigate events over extended period of time as selected and required by an operator or an engineer,
- Being able to view and analyze past events and to derive a range of parameters, key performance indicators, and more complex calculations or applications with the data to assist operators with analyzing behavior and health of distribution systems to make informed decisions.
- Providing a set of tools for pre/post event analysis based on various data types and sources; this can be used for root cause analysis, operator and engineers training, and assessment of operation and design procedures for new technologies and approaches.
- Demonstrating that the proposed monitoring, analysis and visualization system can be used as a base platform for further development of data analytics and real-time monitoring systems, as become required for monitoring and evaluation of newly introduced applications and integration of customer equipment.

It was also concluded that the laboratory setup prepared for integration and demonstration of use cases has clearly facilitated the troubleshooting and analysis of use cases and in performing what-if scenarios, and that would not be possible to accomplish using just data from the actual distribution systems.

5.1.2 Standards, tools and analysis approach applied

The approach for the pre-commercial system demonstration was to use the standard features and functions of the available, off-the-shelf products and to integrate them with existing tools to enhance and achieve the functional requirements for the proposed visualization system that was demonstrated. To achieve that goal, commercially available software and hardware products were used for the test setup. It was concluded that any measurements are available within the capabilities of existing feeder control and monitoring devices that can be used to define new indices and visualize performance aspects of the customer interconnections as parts of use cases. The simulations and test procedures provided successful demonstration of proposed visualization technologies in support of enhanced visibility in distribution circuits and defining greater analytical tools.

5.1.3 Technologies and performances of existing approaches

In the process of demonstration of the monitoring and visualization of measurement data extracted from actual selected distribution circuits, all available technologies present on the distribution circuits were used (e.g. PMUs, SCADA, historian, power quality monitoring). In the process of the circuit selection, in the system design phase (Phase 1 of the project) the objective was to select the circuits with rich set of measurement and control devices, with proper communication infrastructure, and presence of DER.

In cases where the selected circuit did not have sufficient number and type of devices needed to demonstrate some of the developed use cases, RTDS models were used to complement field data. For instance, for demonstration of the visualization capability for a Large Industrial Customer Facility (such as Water Treatment Facility) monitoring use case (Use Case 6), the focus was on reactive power management and flexible local generation use. However, the selected circuit (the Circuit 4) that served such a facility did not have proper communication and data measurement and streaming infrastructure completed at this time, so this use case was successfully demonstrated at ITF lab.

Based on the simulation results, it was concluded that additional values can be provided both to the customer and in enhancing of the circuit operation by closely monitoring and compensating reactive power during load fluctuations.

From the technology survey performed, it was concluded that several promising devices with promising technologies are offered by vendors in the present market that can be used for distribution systems. Selected set of devices was exposed to a rigorous set of the tests (as part of type tests) and the results were quite extensively presented in this report.

From the type tests, it was concluded that although all devices meet the common requirements, defined by the standards (for instance, IEC 37-118 standard for synchrophasor technology), there were differences in their accuracy and available features in measurement quantities that are not commonly used in transmission systems. This finding suggested that there are further opportunities to improve measurement functions for the specific purpose of distribution systems.

5.1.4 Gap analysis and needs

Below is a list of key findings and conclusions related to the gap analysis and areas requiring technology enhancements by vendors:

- During project implementation, it was realized that one of the main barriers associated with PMU utilization is the insufficient communication infrastructure to stream data to control center at high bandwidth and resolution. In todays' utility environment, transmission PMUs don't have problems with communication systems; however, data streaming from distribution PMUs come across challenges such as packets loss and communication data quality. To achieve the full benefit of the system, it is essential to ensure that a reliable communication infrastructure is available. To some extent, data buffering and data interpolation/extrapolation techniques can be applied to mitigate data loss; yet, the fast changing phenomena in new environments are unpredictable and hard to reproduce if actual data does not exist. In addition, enhancing the data processing of the devices can also support localized (device base) data analysis to avoid transferring large amount of raw data to the control centers.
- Dealing with a new technology such as PMUs in distribution systems, it was noted that several commercial products and their features still require significant development and enhancement to meet certain characteristics of distribution systems. In addition, improper pairing and calibration issues of PMU IED along with the voltage/current sensors are more critical and difficult in distribution systems as compared to transmission systems, which adversely affect data quality.
- From the analysis, it was concluded that the phase angle differences across distribution circuits are usually less than 10 degrees; while typically the phase angle error of a physical PMU is around 1 degree to 4 degrees which is considerable (compared with 10 degrees); therefore, it is important to: 1) choose PMUs with proper calibration capability, and 2) calibrate PMUs along with other sensors in the field as part of periodical inspections.
- In one of the selected circuits for the demonstration of use cases (Circuit 4), there were several PMUs installed in the field whose data could not be accessed due to the unavailability of a PDC at the substation. This issue emphasizes the fact that for this technology to be utilized many components are re-

quired to work together in various environments, inside and outside of substations and/or control center. Possible solutions were identified and discussed including standardization of the PMU infrastructure installation and possible data sharing among adjacent substations to facilitate the data concentration and transfer to control center.

- During the project, an event viewer for capturing and analyzing voltage sag and swell of various durations and nature was introduced. This event viewer was proven to be very helpful in identifying and resolving issues with malfunctioning field devices as well as visualizing many events that would not be readily reported by typical SCADA systems and power quality devices. The root-cause analysis was performed by analyzing the data from PMUs in the vicinity and comparing the measurements versus expected outcome. In the absence of a field-base device calibration process, it was concluded that the viewer has the potential to be used as a common tool and component of monitoring platforms for distribution systems.
- During this project, a tap position counter and operation tracker was proposed and demonstrated to monitor performance of voltage regulators in the field. It was concluded that this approach can be utilized as part of field device performance monitoring process to identify the potential wear and tear of the voltage regulators due to frequent tap changes. The approach was proposed as a practical method for identifying and analyzing root causes of the frequent tap changes to manage maintenance aspects and to achieve expected asset life.

5.1.5 Deployment and operational challenges

The main findings were:

- To achieve full benefits of deployment of advanced monitoring and visualization technologies such as the ones proposed and demonstrated during this project, it is necessary to have a measurement, control and communication infrastructure that can reliably handle and support streaming of large amount of data at high resolution with minimum downtime.
- It was concluded that, due to the fact that most PMU technologies are primarily targeted for transmission applications, available PMU devices have limitations for distribution system use. They do not provide a complete set of measurement parameters and indices desirable for distribution system monitoring and analysis. Custom design codes and schemes at PDC level or the post processing of data will be required to calculate and provide indices and statistical data that are readily useable by the engineers.

5.2 Findings Related to the Demonstrated Technology

This section provides findings and conclusions related to prospective adoption of the demonstrated system.

5.2.1 Scaling and large-scale deployment

The main findings were:

- At present, the pre-commercial system was demonstrated with data and measurements from two circuits and a handful of PMU devices. However, based on the amount of data processed and the capability of the visualization tool to incorporate large number of measurement devices, it was determined that system can be scaled up and various data sources can be incorporated.
- The scaling-up can be tested in the simulated environment with the test setup at the laboratory; however, most likely additional enhancement of the lab setup will be needed to also incorporate representation of large scale communication systems with mixed media in a meshed network architecture, to reflect the data traffics and possible latency that can be expected in large scale deployment.

5.2.2 Business considerations

- The proposed monitoring and visualization system was developed with two groups of users in mind, namely, a) distribution system operators, and b) engineers and technicians involved in the event analysis and root-cause assessment of system issues.
- The new monitoring and evaluation schemes could be used for enhancement of the operations by providing additional means of awareness about the system behavior. To bring the technology in the control room and to put it in operational use, a production version needs to be developed; additionally, the GUI needs to be customized to meet operators' needs; operation procedures and training are necessary.

6 Recommendations and Next Steps

The project recommended and demonstrated an advanced monitoring and visualization platform for increasing the visibility into distribution systems to facilitate integration of customer equipment in a safe and reliable environment. The combined utilization of field data monitoring and visualization, and using the simulation environment (in this case the test setup developed at SDG&E Integrated Test Facility) were introduced to model, test and demonstrate some of the features and applications that cannot be demonstrated by using actual field data, due to the limited field data availability and/or limited ability to run into events or create phenomena such as faults, transient changes, circuit reconfigurations, and equipment failure.

Below is a list of key recommendations to further enhance the demonstrated monitoring and visualization technologies in support of enabling distribution system monitoring and visualization beyond substations and to get the monitoring technology ready for utilization by operators and engineers:

- Develop a strategy and technology roadmap to bring the technology into control center to be used by operator as a production level tool. This roadmap should address improvement of existing platform and application and development of new applications, infrastructure and procedures to bring it to operations and the control room and to streamline its use by engineering and planning groups.
- Specify the requirements for new measurement devices, such as distribution PMUs that can provide power quality measurements, in addition to existing standard features.
- Conduct business case analysis to justify cost benefits for various implementation scenarios. PMU in distribution system is an emerging technologies and require involvement from various utility groups and stakeholders to properly define and assign values on the use cases. The business case should consider combination of use cases that provide most value to a larger group of stakeholders. Many root-cause analysis aspects of the proposed technologies may not be readily understood by operators and engineers.
- The project team interacted with many stakeholders, engineers and potential users of the proposed monitoring and visualization system. The application and visualization matrix proposed in the project was shared and discussed to ensure capturing the needs of various groups and common daily operators and engineering activities. It is recommended to further enhance the functional requirement matrix by getting feedback from other departments and by surveying similar approaches used by other utilities. This survey can be later used for developing PI Coresight screens based on the needs of those groups.

6.1 Recommended next steps

To further enhance the demonstrated technology and to resolve some of the accuracy and calibration issues of the commercial PMU devices, it is recommended to share the PMU functional requirements for distribution systems monitoring, and results of the type tests from the project, with vendors interested to enhance the technology. The lack of understanding related to the use cases and measurement approaches for distribution system were associated with some of the accuracy problems observed, which provides areas for future industry collaborations.

It is recommended to work with qualified vendors to develop a portable PMU calibration test equipment for use in the field. The pre-commercial demonstration of the monitoring and visualization technologies showed that periodical testing and calibration of the PMU based devices are essential to avoid large inaccuracy and erroneous measurements. However, for performing the calibrations in the field proper test equipment and testing procedures will be required to safely and accurately test and calibrate devices.

It is recommended to work with standard development agencies and working groups to publish and incorporate some of the findings of and measurement approaches proposed in the project in the distribution PMU guidelines and industry standards. From the type tests, it was concluded that although all devices meet the common requirements, defined by the standards (for instance, IEC 37-118 standard for PMU technology), there were differences in their accuracy and available features in measurement quantities that are not commonly used in transmission systems. This finding suggested that there are further opportunities to improve measurement functions for the specific purpose of distribution systems.

6.2 Adaptability to other utilities and/or the broader industry

It is anticipated that the visualization technology and advanced monitoring demonstrated in this project will be highly appealing to other utilities and beyond. Use of PMU in distribution systems is relatively new, and not many utilities have started to explore advantages and value offering of this technology. The widespread deployment of PV systems and exposing the system to new technologies installed by customers will change the dynamics of the distribution system to the extent that the SCADA system alone would not be able to provide all the information and data required for analyzing the system issues and for operating the system.

7 Metrics and Value Proposition

7.1. Metrics

The main focus of this project was on demonstrating new applications and methods for analyzing the impact of new customer systems on the utility distribution system. The project demonstrated an advanced monitoring and visualization platform that can support operators and engineering in managing the requirement of future complex systems.

The following metrics were identified for this project as potential metrics to consider project benefits at full scale. Given the proof of concept nature of this EPIC project, these metrics are forward looking. Sections 5 and 7 of this report outline the benefits that could potentially be gained from full deployment of this technology.

Table 7-1: Metrics for EPIC 2- Project 5
(Integration of Customer Systems into Electric Utility Infrastructure)

D.13-11-025, Attachment 4. List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation)	See Section
1. Potential energy and cost savings	
a. Number and total nameplate capacity of distributed generation facilities	See Sections 5 & 7
c. Avoided procurement and generation costs	See Sections 5 & 7
i. Nameplate capacity (MW) of grid-connected energy storage	See Sections 5 & 7
3. Economic benefits	See Sections 5 & 7
a. Maintain / Reduce operations and maintenance costs	See Sections 5 & 7
5. Safety, Power Quality, and Reliability (Equipment, Electricity System)	See Sections 5 & 7
b. Electric system power flow congestion reduction	See Sections 5 & 7
c. Forecast accuracy improvement.	See Sections 5 & 7
e. Utility worker safety improvement and hazard exposure reduction	See Sections 5 & 7
i. Increase in the number of nodes in the power system at monitoring points	See Sections 5 & 7
7. Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy	

b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)	See Sections 5 & 7
d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)	See Sections 5 & 7
f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360)	See Sections 5 & 7
j. Provide consumers with timely information and control options (PU Code § 8360)	See Sections 5 & 7

7.2. Value Proposition

Several value propositions of the demonstrated technology and methods introduced in this project are explained below.

7.2.1 Greater awareness about the system

A higher level of awareness and greater values for monitoring and analysis of the system is expected from a system that can utilize and process high resolution of measurement data, along with traditional SCADA type data and AMI data. Traditionally, there has been limitation on providing observability across the circuits (beyond substations). The proposed platform can combine data from various sources to report on power quality and operation of the devices.

7.2.2 Greater reliability

The proposed advanced monitoring and data processing platform utilizes various sources of data at the same time to calculate a series of performance indices for the operation and analysis of the system. Redundant data and combining data from various sources, not only increase the observability and deterministic aspects of the system, it also ensures that events can be analyzed and conclusions can be reached faster to make informed decision on various events, to either prevent a failure, or determine the root-cause in much faster fashion and resolve the stations.

7.2.3 Lower Costs in monitoring and control of the network

In the first glance, the proposed system may not look cost-effective, due to the emerging nature of the technology and the fact that a reliable communication system infrastructure is required to bring the high resolution data back to control center. However, the demonstrated technology enables many fast monitoring and control applications feasible that collectively the portfolio of projects can offer a very high benefit to cost ratio. Several projects and applications should be analyzed and deployed together to ensure the best value propositions can be achieved from the projects.

7.2.4 Increased safety and/or enhanced environmental sustainability

Because the main focus on the proposed advanced monitoring and analysis system is on improving the system visibility and providing fasters and reliable methods for operating the system, safety and integrity enhancement of the system will be the main target. Fast actions are becoming possible based on processing and visualizing high resolution of field data. In addition, because the system becomes more observable, more customer system installation requests and interconnection applications can be processed to expedite the integration and increase the penetration levels.

8 References

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