Pacific Gas and Electric Company

WMP Rapid Earth Fault Current Limiter

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Contents

1.0 Executive Summary 2
2.0 Fire ignition risk from downed wires 4
3.0 Project Objective 4
4.0 Project Scope of Work 4
5.0 Project Accomplishments 5
5.1 Major Tasks 5
5.2 Milestones Achieved 5
6.0 Project Results 6
6.1 REFCL Technology 6
6.2 Demonstration Site Selection 6
6.3 Substation Review 9
6.4 Distribution Review 10
6.5 Balancing Zero Sequence Capacitance 11
6.6 REFCL Equipment Specification & Supplier Selection 15
7.0 System Protection & Automation 17
7.1 Substation Protection 17
7.2 Distribution Protection 18
7.3 Substation Automation 18
7.4 Distribution Automation 18
8.0 Real-time Simulation 19
8.1 Control Hardware-in-the-loop (CHIL) Testing 19
9.0 Distribution Operations 20
9.1 Training 20
9.2 Demonstration 20
10.0 Field Testing 22
11.0 Challenges Encountered 23
11.1 General 23
11.2 Substation 23
11.3 Distribution 27
12.0 Conclusion 28
13.0 References 28
14.0 Appendices 28
14.1 Appendix A – Capacitive Balancing Unit 29
14.2 Appendix B – REFCL SCADA Views 31
14.3 Appendix C – Mobile High Voltage Test Resistor 33

List of Tables

Table 1 Demonstration Project Site Selection Results 9
Table 2 Zero Sequence Currents at Calistoga Substation, baseline 12
Table 3 Calculated Zero Sequence Currents at Calistoga Substation 12
Table 4 Major Protection Zones Balanced with CBUs are Highlighted....13
Table 5 Fuses with the greatest impact to GFN operation when clearing line-line faults 14

List of Figures

Figure 1 Victorian Igntion Testing of Energized Conductor - Without REFCL (Left), With REFCL (Right) ..6
Figure 2 CPUC High Fire-Threat District Map 7
Figure 3 Zero Sequence Capacitance....11
Figure 4 Voltage phasor diagram for an open-delta regulator....15
Figure 5 Substation and GFN equipment single line diagram 16
Figure 6 3200 ohm simulated fault....19
Figure 7 3200 ohm field staged fault 19
Figure 8 Settings Group 1 SEFM/GFN Operation....20
Figure 9 Settings Group 2 SEFM/GFN Operation....21
Figure 10 Settings Group 3 SEFM/GFN Operation....21
Figure 11 Energy Safe Victoria REFCL Capacity Standard [1]....22
Figure 12 Shoofly installed outside fence at Calistoga substation 23
Figure 13 Failed internal PT inside voltage regulator 24
Figure 14 Equivalent circuit of ferro-resonance between voltage regulator and service transformer ...24
Figure 15 L1 fuse supplying RCC inverter blew....25
Figure 16 Burnt boards on RCC inverter....25
Figure 17 Equivalent Circuit for ferro-resonance of grounding transformer [2]....26
Figure 18 Fused cutouts on GFN riser....26
Figure 19 3-phase Viper recloser on GFN riser....26
Figure 20 Summer peak load unbalance 28

Table of Acronyms

3I0	Zero sequence current or ground current
5MM	5 Minute Meeting
ASC	Arc suppression coil
ATS	Applied Technology Services
CBU	Capacitive Balancing Unit for reducing standing neutral current
CPUC	The California Public Utilities Commission
CHIL	Control hardware-in-the-loop
CT	Current Transformer
CYME	CYME is a Power Engineering software used for electric distribution studies
EPIC	Electric Program Investment Charge
GFN	Ground Fault Neutralizer
GIS	Geographic Information System
GPS	Global Positioning System
HFTD	High Fire Threat District
IPAC	Integrated Protection Auxiliary Cabinet
iPCGrid	Innovations in Protection and Control for Greater Reliability Infrastructure Development
MV	Medium Voltage (1 - 35kV)
PG&E	Pacific Gas & Electric
PSPS	Public Safety Power Shutoff
PT	Potential Transformer
pu	Per unit
RCC	Residual Current Compensator
REFCL	Rapid Earth Fault Current Limiter
RFI	Request for Information
RMS	Root Mean Square
RTDS	Real-time Digital Simulator
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric Company

1.0 Executive Summary

This report summarizes the project objectives, technical results and lessons learned for the WMP C.10 Proactive Wires Down Mitigation (REFCL) demonstration project. The project was authorized in December 2018.

Many types of distribution faults and equipment failures have the potential to cause outages and even ignite wildfires. Ground faults such as transformer failure, insulator failure, vegetation contact, and downed power lines make up over 65% of the faults on electric distribution in high fire threat districts (HFTD). With the power system solidly grounded, as is common practice in the USA, the ground fault current magnitude is hundreds or thousands of Amps, well above the ignition threshold. In other parts of the world, resonant grounding is used to limit the ground fault current typically below 100 Amps.

In Australia, an extension of resonant grounding known as Rapid Earth Fault Current Limiter (REFCL) technology was deployed for the primary purpose of preventing ignitions from ground faults. In this project, PG&E sought to demonstrate the REFCL technology at one Tier 3 HFTD distribution substation for automatically and rapidly reducing the flow of current and risk of ignition in single line to ground faults. Demonstrating that the technology could be successfully integrated with PG&E systems to inform the scalability of the technology for future deployments was a key objective.

Site selection criteria was created and the Calistoga substation in Napa Valley was selected for demonstrating the REFCL technology. It is a 60 kV to 12 kV single bank distribution substation with two feeders of total circuit mileage approximately 152 miles. This configuration was representative of many of the substations supplying the highest fire risk distribution circuits within PG&E's service territory.

During a fault, REFCL increases the neutral voltage to reduce the line to ground voltage of the faulted phase, which increases the line to ground voltage of the other two phases by 1.72 times. A detailed review of insulation levels of primary connected substation and distribution equipment was performed to identify at risk equipment for continuous operating voltage of 14.4 kV. The major changes required were the substation voltage regulators, substation service transformer, substation bus PTs, a quarter mile section of underground cable, and installation of an isolation transformer at a primary connected customer. A six minute stress test of each phase was performed to verify adequate insulation levels, and no equipment failures were encountered from the stress test.

One critical performance factor for REFCL sensitivity was the standing neutral current at the substation bank. To reliably detect 0.5A ground faults, the standing neutral current needed to be reduced to 0.1A or lower by balancing the leakage currents from each phase on the distribution circuits. Phase transposition allowed for coarse balancing, however a new type of equipment known as a Capacitive Balancing Unit (CBU) was developed to be compatible with PG&E's distribution circuits. The CBUs allowed for remote balancing in 0.03A steps via PG&E's distribution SCADA system. Thirteen (13) CBUs were installed between the two distribution circuits. After balancing, the standing neutral current at the bank was successfully reduced below 0.1A.

Maintaining balanced leakage currents despite changes in load was required. All voltage regulating devices needed to be converted to closed delta and a three-phase voltage regulator controller was implemented for group tapping of all three phases together. Unfortunately, the unbalanced load currents during peak summer temperatures caused substantial voltage unbalance, resulting in reduced

REFCL sensitivity. A load balancing study was performed to correct the locations where the load unbalance was the most pronounced and make changes to balance the load.

After completion of the above, staged fault testing using a mobile high voltage resistor bank was performed. The testing involved connecting a cable to one phase of the distribution circuit at a location and momentarily closing in the grounded resistor bank to create a fault of a fixed resistance. One test was performed at 3200 ohms where the REFCL system detected the fault, mitigated the fault current to below ignition levels based on the Energy Safe Victoria (Australia) standard, and correctly identified the faulted feeder.

Although one successful fault test was performed, the REFCL technology was not successfully integrated with PG&E's system as of July 2021. The REFCL equipment used a grounding transformer to make the electrical connection in the substation. After the first test, the grounding transformer failed, causing a major setback for the demonstration. The REFCL technology is not operational at PG&E right now, and PG&E will continue work to integrate REFCL at Calistoga. PG&E has no plans to move forward with additional REFCL deployments until the operation and performance is validated at the Calistoga site.

2.0 Fire ignition risk from downed wires

Energized wires down scenarios on PG&E's distribution circuits pose a public safety and fire ignition risk. These scenarios are difficult for convential distribution protection schemes to detect and de-energize the wires on the ground, since PG&E's existing distribution protection scheme relies on detecting high fault current to trip protective devices. This detection scheme can be too late to prevent a fire ignition from an energized wire down or may not detect the energized wire down at all in the case of a high impedance fault. Additionally, power is typically shut off to customers downstream of the protective device during a momentary fault, including a momentary single line to ground fault.

PG&E looked into methods to proactively mitigate safety risk associated with wires down events. In Australia, Rapid Earth Fault Current Limiter (REFCL) technology has been implemented to reduce the risk of wildfires from electrical distribution. REFCL technology works to rapidly reduce the flow of fault current to near zero levels and substantially reduce the risk of ignition in ground faults in PG&E's high risk fire areas. REFCL is over ten times more sensitive than conventional protection to detect the ground fault and actively responds to reduce the fault current to prevent fire ignition. REFCL can reduce the fault current with no immediate service interruption to customers, effectively eliminating momentary ground faults for improved reliability.

Since REFCL is an extension fo resonant grounding, it is only practical for 3-wire, uni-grounded substation banks. It would be cost prohibitive to convert 4-wire multi-grounded banks to 3-wire for the sole purpose of REFCL. Over 90% of the distribution circuits within high fire threat districts within PG&E territory are 3-wire circuits.

3.0 Project Objective

The primary objective for the project was to build, test, and make operationally ready the REFCL technology to reduce risk of ignition in single phase to ground faults in PG&E's high risk fire areas. Successful demonstration that the technology could be integrated with PG&E systems to inform the scalability of the technology for future deployments was also key. The Energy Safe Victoria REFCL performance standard was used as a target metric.

4.0 Project Scope of Work

By referencing existing, comprehensive REFCL ignition testing which was done in Australia, the project team determined that it was unnecessary to repeat this testing and avoid additional costs of the project. The primary scope of work was:

Phase 1: Engineering and Construction

- Project design
- Equipment order
- Test in Proof Of Concept RTDS Lab
- Field and substation work
- Train and educate all departments affected by this technology

Phase 2: Field Demonstration & Operation
- Commissioning & testing
- Fault location testing
- Final report and recommendations

5.0 Project Accomplishments

5.1 Major Tasks

5.1.1 Control hardware-in-the-loop (CHIL) test bed using real-time digital simulator (RTDS)

5.1.2 Container design for Ground Fault Neutralizer on 12 kV circuits

5.1.3 GFN installed in Calistoga substation

5.1.4 Capacitive Balancing Unit design

5.1.5 High voltage test trailer for field fault testing

5.2 Milestones Achieved

5.2.1 CHIL test bed demonstrated proof of concept

5.2.2 First REFCL installed in USA

5.2.3 REFCL deployed to one Tier 3 substation including Arc Suppression Coil, Ground Fault Neutralizer Control Cabinet, Residual Current Compensator, CTs, relays, capacitive balancing units, upgraded LRs, fuse savers, closed delta regulator banks, and isolation transformer for primary customer

5.2.4 GFN commissioned and used to shift power system neutral voltage to full displacement and stress test of primary insulation on the circuits

5.2.5 One staged fault test successfully performed with fault resistance of 3200 ohms. The REFCL system detected the fault, mitigated the fault current to below ignition levels per the Energy Safe Victoria standard [1], and correctly identified the faulted feeder. The steady state fault current was 0.08 Amps.

6.0 Project Results

6.1 REFCL Technology

The specific type of REFCL the project demonstrated was a Ground Fault Neutralizer (GFN) which combines an Arc Suppression Coil (ASC), Residual Current Compensator (RCC), and controls to rapidly minimize the ground fault current to less than 0.5 Amps. Based on ignition testing in Victoria, Australia, reducing the current below 0.5A and the fault energy below 0.1 A^2s reduces the probability of fire ignition by up to 90% for single line to ground faults (Figure 1).

Power systems with a large amount of circuit mileage have a high residual component of the ground fault current, which resonant grounding alone does not reduce to a level low enough to prevent a fire ignition. This residual fault current is due to energy losses on the network and leakage current across the thousands of insulators on the un-faulted phases. A GFN using an RCC actively reduces the residual to reduce the fault current to basically zero during a single line to ground fault. REFCL has no effect at reducing fault current for line-line faults.

Figure 1 Victorian Igntion Testing of Energized Conductor - Without REFCL (Left), With REFCL (Right)

6.2 Demonstration Site Selection

Early in the project, some basic site selection criteria were defined to aid in the site selection for the demonstration project. A third party contractor supported the site selection process.

6.2.1 High Fire-Threat District

The primary objective of the REFCL technology was to reduce the risk of fire ignition from overhead powerline facilities to improve public safety. After fires in the state of California in 2007, the California Public Utilities Commission (CPUC) started rulemaking to consider and adopt regulations to protect the public from potential fire hazards associated with overhead powerline facilities and nearby aerial communication facilities. Several of the adopted fire-safety regulations apply only to areas, referred to as "high fire-threat areas," where an elevated risk exists for power line fires igniting and spreading rapidly. Eventually the CPUC rulemaking resulted in a comprehensive High Fire-Threat District (HFTD) map (Figure 2), which identifies areas across California that have the highest likelihood of a wildfire impacting people and property, and where additional action may be necessary to reduce wildfire risk. The high risk areas are broken down as follows:

- Tier 3 areas are at extreme risk for wildfire, highlighted in red on the map
- Tier 2 areas are at elevated risk for wildfire, highlighted in amber on the map
- Zone 1 Tier 1 High Hazard Zones are areas with high numbers of dead and dying trees.

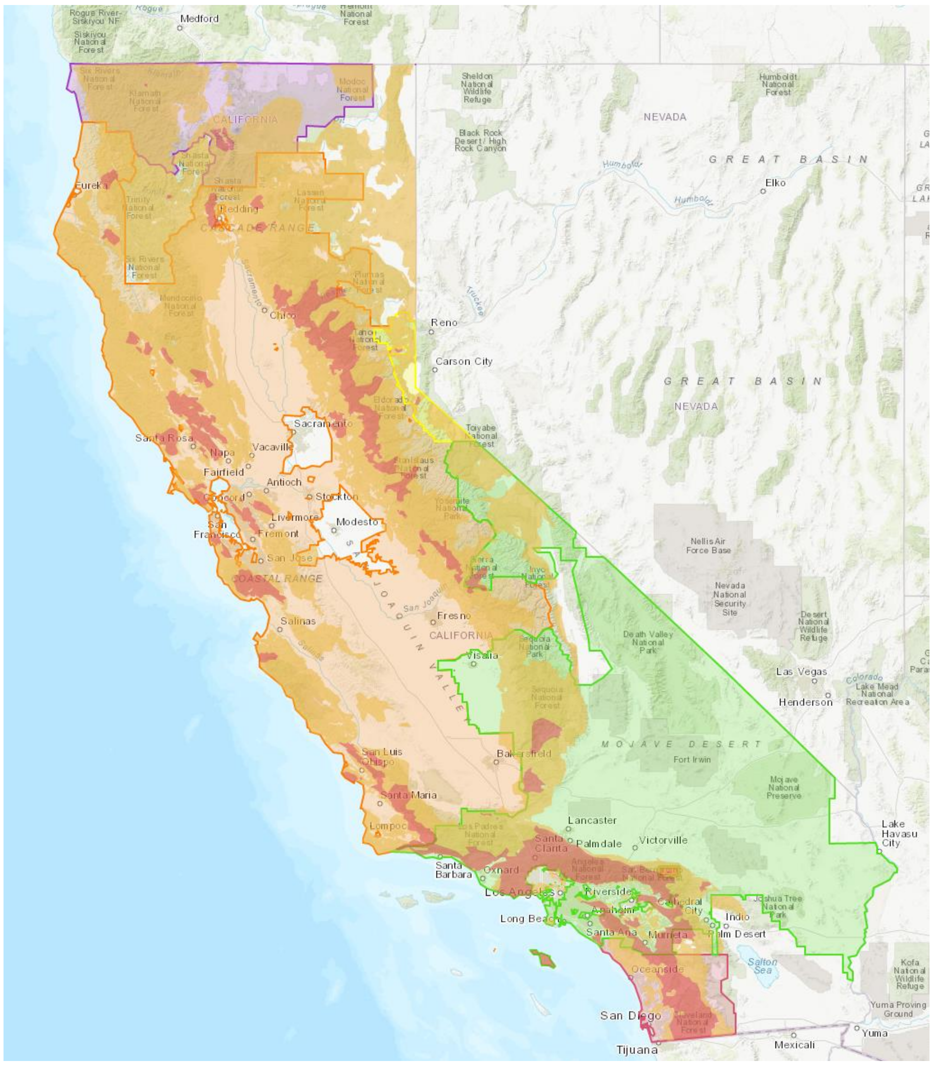


Figure 2 CPUC High Fire-Threat District Map

For the REFCL demonstration project, the primary criterion was for the site to be located within a Tier 3 Fire-Threat area.

6.2.2 **Number of Wire Down Events**

Historical wire down event data was used to determine the locations with the highest incidences of wire down events. Higher incident rates were given a higher score.

6.2.3 Three-Wire Distribution Circuits

A key technical requirement for REFCL was a distribution substation bank where the secondary neutral is uni-grounded and the distribution circuits are 3-wire with no neutral. It would be cost prohibitive to install REFCL to protect existing 4-wire circuits which use a neutral to serve load, since the entire distribution network would have to be rebuilt and converted to uni-grounded. PG&E's total circuit mileage in High Fire-Threat Districts (T2, T3 and Z1) was 25,597 circuit miles, and the total 3-wire (12, 17, 21 kV) circuit miles was 23,731 miles, over 90% of the total in HFTD. This showed high opportunity for REFCL implementation. Only substation banks feeding 3-wire circuits were considered for the demonstration project.

6.2.4 Substation Logistics

The substation needed to have spare physical space available to install the REFCL equipment and controls systems. Ideally the selected substation had existing room for the new equipment. It was preferred that the selected substation have proximity to the cross-functional support needed for the project, which was primarily located in the San Francisco Bay Area. Distribution substations with only one transformer bank and existing SCADA communications were scored higher.

6.2.5 Distribution Circuit Logistics

The distribution circuits connected to the substation should have total circuit mileage typically representing all of the circuits in High Fire-Threat Districts. Fewer two-wire taps was preferred to make it easier to balance the natural leakage currents of the distribution circuits. The distribution circuits should not have high circuit mileage consisting of underground cable, limited to 30 miles for a 100A arc suppression coil. Another requirement was to have a minimum number of primary customers, preferably zero primary customers, connected to the distribution circuits fed from a REFCL bank. With REFCL, primary customers needed to be electrically isolated using additional utility equipment to ensure reliability. Ideallly the connected distribution circuits had newer facilities, rated for at least phase to phase voltages, to minimize replacement of existing infrastructure due to insufficient voltage ratings for the demonstration project.

6.2.6 Selection

A scoring matrix was developed based on the criteria above, and the results are shown in Table 1. Calistoga substation, a 12 kV 3-wire single bank substation, was selected for the demonstration project.

Substation	Meets Exclusion Criteria	Matrix Score
Bolinas	Yes	33.0
Calistoga	Yes	28.2
Clark Road	No	24.0
Cloverdale	Yes	25.7
Geyserville	Yes	27.6
Girvan	Yes	25.6
Konocti	Yes	24.7
Mendocino	Yes	27.1
Oro Fino	Yes	22.3
Otter	Yes	30.2
Perry	Yes	28.4
Redbud	Yes	31.2

Table 1 Demonstration Project Site Selection Results

6.3 Substation Review

A comprehensive review of the substation and all substation equipment was performed. The main requirement was to verify all equipment was rated for phase to phase voltage levels, 14.4 kV in this case. PG&E ATS Electrical unit performed a grounding study for the substation to check touch and step potential and ensure personnel safety inside the substation.

6.3.1 Equipment Scope

The substation equipment review resulted in the following scope:

- Replace voltage regulators in closed delta, insufficient voltage rating
- Install new, matched sets of feeder breaker current transformers (CTs)
- Replace bus potential transformers (PTs), insufficient voltage rating
- Replace substation service transformer with line-line connection
- Isolate bank neutral bus and install neutral bus grounding recloser
- 12 kV bus structure modifications for new switches and recloser
- Install Ground Fault Neutralizer enclosure
- Upgrade station battery capacity
- Upgrade feeder breaker protection and automation package to current standard
- Install Field Area Network
- Grounding grid improvements based on grounding study

6.4 Distribution Review

A comprehensive review of the distribution circuits and all distribution equipment was performed. The main requirement was to verify all equipment was rated for phase to phase voltage levels, 14.4 kV in this case. A basic insulation level (BIL) of 95 kV was also defined as a requirement. Considerations for minimizing standing neutral current were also accounted for.

6.4.1 Equipment Scope

The distribution equipment review resulted in the following scope:

- Lightning Arresters removal from line reclosers if only 12 kV rated
- Replacement of auto boosters with closed delta voltage regulator banks
- Replacement of open delta voltage regulators with closed delta
- Replacement of line reclosers and controllers for sensitive earth fault detection and support for Field Area Network integration
- Isolation transformer for one primary connected customer
- Replacing three-phase fuse arrangements with FuseSavers
- Phase connection swaps for leakage current balancing

6.4.2 Overhead Conductor

The two Calistoga distribution circuits combined for approximately 152 circuit miles of overhead conductor, consisting of ACSR and copper. Two-phase taps were identified using GIS mapping data.

6.4.3 Underground Cable

The two Calistoga distribution circuits combined for approximately 18 circuit miles of underground cable. Some runs of cable were two-phase, which introduced substantial unbalanced leakage currents and increased the standing neutral current at the substation bank. Nearly all of the underground cables were rated 22 kV or greater, while a few sections totaling approximately 1500 ft were rated 15 kV with an age of over 40 years. The 15 kV cable was identified as being at risk due to temporarily elevated phase to ground voltages with REFCL, so PG&E ATS Electrical unit performed Very Low Frequency (VLF) hipot tests in the field. Three sections of cable failed the test above 8 kV. The complete test report reference was ATS 006.4.2-19.10. New shorter runs of 25 kV cable were installed and the failed cable was abandoned.

6.4.4 Field Phasing Identification

PG&E did not have detailed phasing information for the vast majority of its distribution circuits. Prior to the initiation of the Proactive Wires Down demonstration project, it was decided to perform field phasing identification to help with deployment of advanced sensors for a different project. Field phasing identification confirmed which phases a piece of equipment was connected to. A local crew used the standard PG&E Phase ID tool to identify the connected phases for each service transformer in the field. The information was compiled in a spread sheet.

Once the field phasing information was obtained, PG&E ATS used a python script to update the CYME distribution model with the phasing information for primary connected equipment. This phase identified model was utilized for correcting load unbalance load and capacitive balancing.

6.5 Balancing Zero Sequence Capacitance

6.5.1 **Background**

Based on the Victorian Bushfire Safety Program Trials Report, fault detection performance was an essential part of achieving fire risk reduction. If the fault is not detected, the fault current cannot be mitigated and the fault itself isolated. Minimizing the standing neutral current in the substation was the most effective way to increase fault sensitivity for resonant grounded systems. The GFN used neutral voltage for a fault detection threshold, and the standing neutral current manifested as neutral voltage, thus reducing the detection margin. For the distribution networks, the circuit mileage of each phase was not identical, resulting in unbalanced zero sequence capacitance on each phase, illustrated in Figure 3.

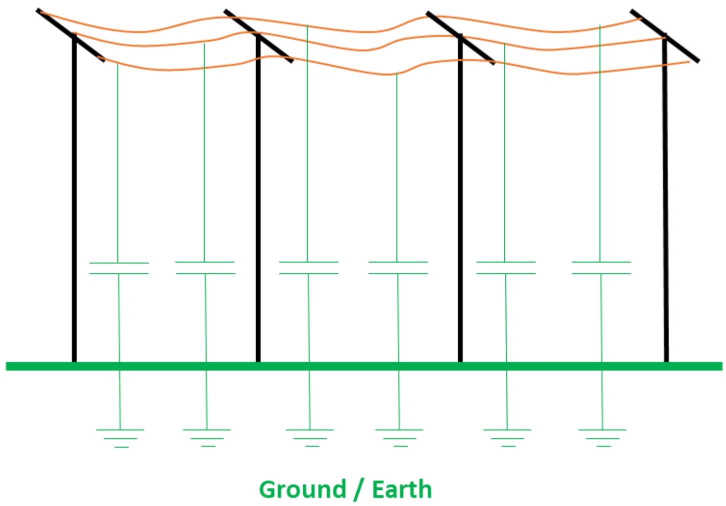


Figure 3 Zero Sequence Capacitance

The zero sequence capacitance was distributed along each phase and typically represented as a susceptance per unit length. This zero sequence capacitance resulted in small leakage currents to ground from each phase, dependent on the voltage. The rule of thumb for calculating this leakage current for 12 kV distribution systems was:
12 kV Overhead conductor: 0.048 Amps / mi
12 kV underground rated cable: 2.57 Amps / mi

PG&E ATS developed python scripts to calculate the total downstream susceptance per phase in the CYME distribution model for the Calistoga circuits. From this, the leakage currents were calculated at nominal voltages. The baseline leakage current contribution from each phase is shown in Table 2. The CYME model then resulted in a total charging current of 53.4 Amps. The arc suppression coil must be rated for this current with substantial margin to allow for future expansion of the distribution network, especially if additional underground cable installations were planned. More detail on this is in the REFCL Equipment Specification and Supplier Selection section.

The actual resonant point measured during commissioning was 72 Amps. The difference is from the grounding transformer and ASC losses, CBUs, and greater leakage currents from underground cable.

	IA	IB	IC	Total Amps	Overhead mi	Underground mi
CYME Estimation	19.0	15.5	18.9	**53.4**	158.7	19.1
Rule of Thumb	-	-	-	**56.7**	158.7	19.1
Actual measured	-	-	-	**72**	-	-

Table 2 Zero Sequence Currents at Calistoga Substation, baseline

Before any changes to the distribution circuits were made for the demonstration project, the leakage currents were unbalanced by about 6%, resulting in a standing neutral voltage of over 30V secondary. This neutral voltage would be too great and not allow enough margin for sensitivity to high impedance ground faults. Therefore, the CYME distribution model was used to study the capacitive balance and reduce the standing neutral voltage under normal and abnormal conditions.

6.5.2 Phase connection swaps

To coarsely balance the zero sequence capacitance, phase connections for single phase taps were swapped. Since the distribution circuits were three-wire, what is referred to as single phase taps actually consisted of two phase conductors. In total, eleven phase connections were swapped where single phase taps met the three phase main line. This resulted in good balance at the substation, shown in Table 3, however each protection zone also needed to be considered for when the circuit operated in an abnormal state, such as after isolating a fault.

	IA	IB	IC	3I0
Baseline	19.0	15.5	18.8	**3.4**
After phase swap	17.9	17.6	17.9	**0.3**

Table 3 Calculated Zero Sequence Currents at Calistoga Substation

6.5.3 Capacitive Balancing Units (CBU)

Each distribution feeder was balanced to 100 mA, while design values were used to balance the major line recloser protection zones. To finely balance each major breaker and recloser protection zone, capacitive balancing units (CBU) were designed to actively inject ground current in 0.03 Amp increments from each phase. Each CBU consisted of three single phase 12,000:120V 15KVA YG/YG transformers, fused cutouts, and LV control cabinet containing the controller, LV capacitors, and contactors. Soil resistivity measurements were taken at each CBU location and two grounding designs were developed to keep the ground resistance below 5 ohms. Further details about the CBU design can be found in the Appendix.

The CBUs were installed at thirteen locations within major protection zones, highlighted in

EqNo	3I0 BEFORE	CBU IA	CBU IB	CBU IC	3I0 AFTER
1102/2	0.37	0.07	0.05	0.40	0.05
1101/2	0.21	0.24	0.24	0.00	0.06
890	0.66	0.57	0.60	0.00	0.12
634	0.33	0.00	0.35	0.04	0.00
706	0.21	0.00	0.21	0.00	0.00

43924	0.56	0.60	0.00	0.00	0.04
736	0.37	0.00	0.31	0.40	0.01
894	0.18	0.00	0.19	0.17	0.00
769230	0.10	0.11	0.01	0.00	0.00
734	0.41	0.00	0.42	0.04	0.01
NEWLR	0.19	0.19	0.00	0.00	0.00
89150	0.09	0.00	0.10	0.00	0.02
35588	0.02	0.00	0.00	0.02	0.00
66730	0.00	0.00	0.00	0.00	0.00
1087	0.03	0.00	0.03	0.00	0.01
705	0.01	0.00	0.00	0.00	0.01
82956	0.00	0.00	0.00	0.00	0.00

Table 4. The CBUs allowed for the substation bank to be balanced to 100 mA. The standing neutral voltage was decreased substantially to 3.5V secondary, increasing the reliable fault sensitivity of the GFN.

EqNo	3I0 BEFORE	CBU IA	CBU IB	CBU IC	3I0 AFTER
1102/2	0.37	0.07	0.05	0.40	0.05
1101/2	0.21	0.24	0.24	0.00	0.06
890	0.66	0.57	0.60	0.00	0.12
634	0.33	0.00	0.35	0.04	0.00
706	0.21	0.00	0.21	0.00	0.00
43924	0.56	0.60	0.00	0.00	0.04
736	0.37	0.00	0.31	0.40	0.01
894	0.18	0.00	0.19	0.17	0.00
769230	0.10	0.11	0.01	0.00	0.00
734	0.41	0.00	0.42	0.04	0.01
NEWLR	0.19	0.19	0.00	0.00	0.00
89150	0.09	0.00	0.10	0.00	0.02
35588	0.02	0.00	0.00	0.02	0.00
66730	0.00	0.00	0.00	0.00	0.00
1087	0.03	0.00	0.03	0.00	0.01
705	0.01	0.00	0.00	0.00	0.01
82956	0.00	0.00	0.00	0.00	0.00

Table 4 Major Protection Zones Balanced with CBUs are Highlighted

6.5.4 Maintaining capacitive balance after Line-Line faults

One major advantage for solidly grounded distribution networks is improved reliability through coordination between protective devices. This is achieved through time current curves, where downstream protective devices operate first to minimize the number of customers impacted when a fault occurs. A typical coordination is between fuses and line reclosers.

With solid grounding, the fuses blow to clear any fault with sufficiently high fault current, whether it is a line-ground fault or a line-line fault. With the GFN, the fault currents for line-ground faults are very small, so fuses do not blow to isolate the fault. If a line-line fault occurs, the fuses blow due to the high fault current, regardless if the substation bank neutral is solidly grounded or not.

When a fuse blows for line-line fault, it can introduce capacitive unbalance and cause false operation of the GFN. When the fuse operates, the downstream zero sequence capacitance is removed from the rest of the distribution network. If the resulting ground current delta is substantially large, it can appear as though a ground fault occurred on the network to the GFN and cause false operation of the GFN due to the neutral voltage exceeding the detection threshold because of the unbalance.

The CYME distribution network model was studied to assess the increase in neutral current at the substation bank if two fuses blow to clear a line-line fault. The worst case condition at each fuse location was analyzed. If clearing a line-line fault resulted in the neutral current in the substation increasing by 200 mA or more, then the fuses at that location were targeted for replacement with a 3-phase gang operated protection device.

The preferred method to eliminate the unbalance from line-line faults was to replace the fuses with FuseSaver devices, capable of group tripping. In the case of a line-line fault, the FuseSavers tripped all three phases, maintaining capactive balance. The FuseSavers required at least one Amp of load current on each phase to stay powered on and keep the battery charged to enable the group tripping function. Some fuse locations did not meet the load requirement, so the fuses were either removed or a new line recloser was installed.

For the demonstration project, the team decided to exclude fuses on a riser pole with the sole purpose of protecting underground cable sections. Eight fuse locations were left alone due to the highly unlikely probability that the fuses would blow to protect the cable when the GFN system is operating at its highest sensitivity.

In total, 26 three-phase fuse locations had phase-phase fault unbalance concerns and needed to be addressed with FuseSavers, Line Reclosers, or US Switches with Fault Indicators. Line-line faults at some fuse locations would result in substantial neutral current and false operation of the GFN (Table 5).

EqNo	OH ft	UG ft	IA	IB	IC	Neutral current increase A
791_042711101	58576	10004	1.33	1.06	1.97	1.97
8339_042711101	75089	10117	1.09	0.83	1.68	1.68
435_042711102	11275	7873	1.29	1.29	1.29	1.29
1049_042711101	28418	7221	1.16	1.21	1.03	1.21
435819_042711101	11177	6324	1.13	0.26	1.13	1.13
8355_042711101	6384	5396	0.85	0.91	0.91	0.91

Table 5 Fuses with the greatest impact to GFN operation when clearing line-line faults

To summarize, multiple approaches were taken to maintain balanced zero sequence capacitance even when protective devices operate to isolate various types of faults occurring on the distribution networks. To reliably mitigate fault currents of 0.5A, the substation bank was balanced to 100 mA while striving to maintain 200 mA of unbalance or better through normal operation.

6.5.5 Maintaining balance with single phase voltage regulation

Distribution line voltage regulators were used on long, radial circuits to maintain service voltage within acceptable limits, generally +/- five percent of nominal. Previously on these circuits, two single phase voltage regulator units were used per regulator bank to regulate the voltage of all three phases in an open delta connection. This caused a drastic shift in the apparent neutral depending on load and tap position, which changed the amount of capacitive ground current flowing from each downstream phase and increased the standing neutral current at the substation bank (Figure 4).

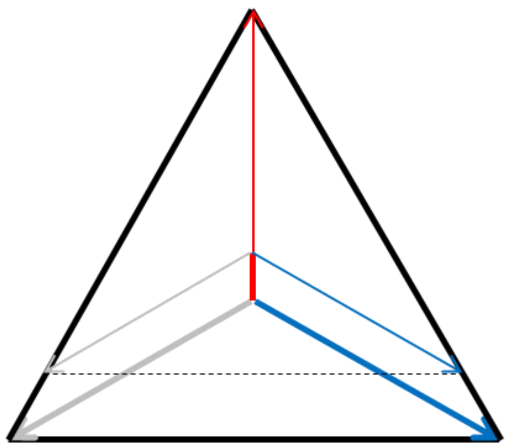


Figure 4 Voltage phasor diagram for an open-delta regulator

The open delta voltage regulating banks were replaced with closed delta 3-phase voltage regulator banks. A multi-phase regulator controller was used to tap all three phases in locked step or group mode based on the average voltage of all three phases.

During the summer peak, unbalanced load currents were a challenge for the group tapping. The unbalanced load currents resulted in too much voltage unbalance, so some of the voltage regulators had to be temporarily changed to independent operation to keep each phase's voltage within the acceptable range.

The load unbalance was somewhat localized, so field SCADA measurements and the CYME distribution model were used to determine where to make phase swaps on 3-phase tap lines to balance the load currents. An incremental approach was taken to observe the baseline load unbalance, swap phase connections, and observe the resulting load unbalance.

6.6 REFCL Equipment Specification & Supplier Selection

6.6.1 Swedish Neutral AB was selected as the REFCL supplier, as at the start of the project they were the only REFCL supplier with proven field installations of REFCL technology for ignition prevention in Australia. PG&E collaborated with Australian utilities who had deployed this technology in the field, and using the same supplier of the equipment enabled better collaboration and building on the work the Australians started. The Victorian REFCL ignition test results were leveraged to determine performance benchmarks for the project.

6.6.2 The original specification for the Swedish Neutral GFN was for a 50 Amp system. After project team members traveled to Australia and had more detailed discussion about system sizing, it was determined that the 50 Amp system would not be adequate. A change order was processed and Swedish Neutral delivered a 100 Amp GFN. After capacitive balancing, the GFN tuned to resonance at 72 Amps, so it confirmed the 50 Amp GFN would have been inadequate.

6.6.3 For application in the USA, Swedish Neutral recommended a grounding transformer be used to provide electric service to the GFN components. The RCC inverter for example is built for 3-phase 400V input. This is a nonstandard service voltage in the USA, so the grounding transformer with secondary service was used in the GFN. The connections between the substation and grounding transformer are shown in Figure 5.

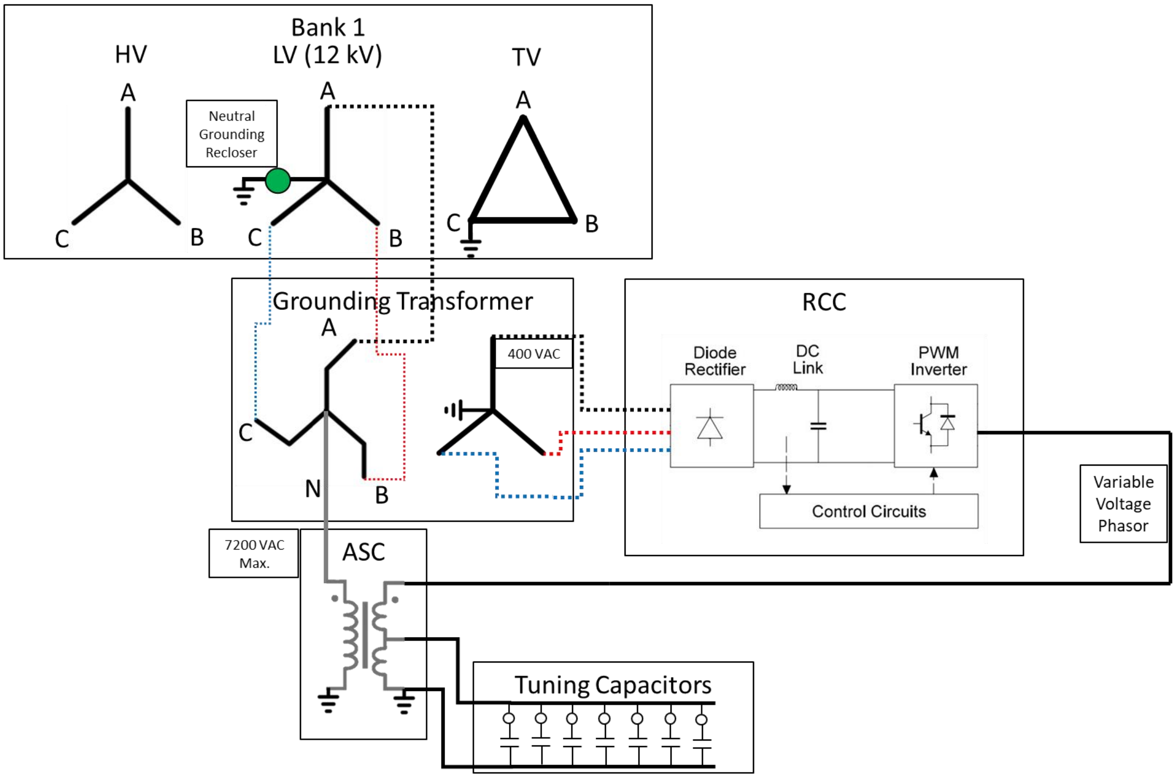


Figure 5 Substation and GFN equipment single line diagram

6.6.4 The supplier tested all components at 60 Hz as part of the factory acceptance testing (FAT). Project team members visited on site to witness the FAT.

6.6.5 The GFN Neutral Manager controllers did not natively support DNP3 protocol for SCADA. This required development of a Substation Earth Fault Management (SEFM) relay using an SEL Axion RTAC. The Australians also used a SEFM to their own specification using different SEL hardware.

6.6.6 The container form factor 7200V 100A GFN can be potentially used as a standard for future REFCL deployments. Substation standards group was engaged to start the process. Potential improvements include:
- RCC inverter and air conditioner compatible with 480Y/277 or 120 voltage
- Adherence to PG&E wiring standard, particularly "other end" wire marking
- Adding a blank Rittal control cabinet with swing panel for PG&E installed SEL Axions, FT switches, communication adapters, etc
- 24VDC coil voltage for ASC tuning capacitor contactors
- Thicker sheet metal panels for container floor and personnel door
- Conduits for wiring for smoke alarms and fire alarm system
- Built-in redundancy for Set A and Set B controls

7.0 System Protection & Automation

7.1 Substation Protection

7.1.1 System Protection was consulted for changes to the substation protection and integration of the REFCL scheme.

7.1.2 Transformer bank secondary, GFN supply, feeder 1101, and feeder 1102 CTs were each summed for 3I0 to bring into the Swedish Neutral Manager controllers. The GFN treated each of these as "feeders" and performed fault identification to locate the fault to one of the three zones.

7.1.3 The feeder circuit breaker protection was replaced with the updated IPAC standard cabinet consisting of SEL 351 and GE F60 relays. Distribution Fault Anticipation (DFA) devices were also installed in the IPAC cabinets for the EPIC 2.34 project and digital fault recording.

7.1.4 The 12 kV 3-phase supply for the GFN container was originally protected with 10E fuses in the design. After blowing one of the fuses during commissioning, ferro-resonance was encountered when trying to close one fuse at a time with the grounding transformer in a no load condition and ASC tuned to 72A position. The fused design was replaced with a 3-phase gang operated Viper recloser to protect the GFN equipment.

7.1.5 The transformer bank secondary ground bus was converted to a neutral bus and a single Viper ST recloser (Neutral/2) was installed with a hook disconnect bypass switch to give flexibility in solidly grounding or resonant grounding the transformer bank secondary. The Viper ST recloser was SCADA operable and the SEFM provided supervision to automatically close and solidly ground the transformer bank so that convential protection would see ground faults and isolate them during low fire index conditions.

7.1.6 The transformer bank primary protection was left as-is with protection from an ABB gas insulated switchgear (CB72). SEFM trip outputs were wired to CB72 to trip for Neutral/2 fail to close or permanent bank or bus ground fault.

7.1.7 ATS Electrical Unit performed an arc flash study for the GFN container and determined standard Cat 2 PPE was acceptable for personnel working in the low voltage side of the container. The high voltage side needed to be cleared before for personnel could safely enter.

7.2 Distribution Protection

7.2.1 Old line reclosers were replaced and new line reclosers were installed. New line reclosers were also separately installed as part of the PSPS impact mitigation work.

7.2.2 The line reclosers used were 3-phase Viper ST with standard Beckwith M7679 controller. These controllers allowed for remote setting group changes and communication with multiple DNP3 masters.

7.2.3 The line recloser at a primary customer with approximately 800 kW of generation was set up with 3E0 protection to trip in the case of ground fault. The new isolation transformer installed at this primary customer successfully protected the customer premise from any increased line to ground voltages resulting from REFCL operation.

7.3 Substation Automation

7.3.1 Substation controls were automated to the extent possible for seamless transition between solidly grounded and resonant grounded configuration of the substation transformer bank.

7.3.2 The existing GE D20 RTU was programmed to support SCADA integration of the new multiphase CL7 voltage regulator controller, Substation Earth Fault Management (SEFM) Relays, and distribution feeder breaker IPACs.

7.3.3 Substation Automation developed the programming for the SEFM Relays, with details in a separate section.

7.4 Distribution Automation

7.4.1 The Calistoga distribution circuits had FLISR functionality. FLISR was disabled during the demonstration project.

7.4.2 Capacitive Balancing units, Voltage Regulators, and Line Reclosers were integrated into distribution SCADA.

7.4.3 A Field Area Network (FAN) was deployed for low latency communication between devices and to support the SEFM recloser tripping algorithm. The topography of the valley in Calistoga made the FAN deployment more challenging, so it took design revisions and in-person surveying to improve the performance of the FAN. The recloser tripping algorithm was not yet deployed in the field.

8.0 Real-time Simulation

8.1 Control Hardware-in-the-loop (CHIL) Testing

8.1.1 CHIL Testing was performed at ATS utilizing a real-time digital simulator (RTDS) and Swedish Neutral Neutral Manager controllers. The equivalent Calistoga substation and distribution circuit parameters were modeled in RSCAD to test proof of concept of the REFCL technology and gain a better understanding of sensitivity and performance factors.

8.1.2 The simulation was used to gain experience in making the connections to the GFN controllers, commissioning, settings changes, studying impact of capacitive balance on sensitivity, fault confirmation, and testing SEFM logic before field deployment.

8.1.3 For a 3200 ohm fault, the simulation result (Figure 6) correlated well with the successful staged fault test in the field (Figure 7).

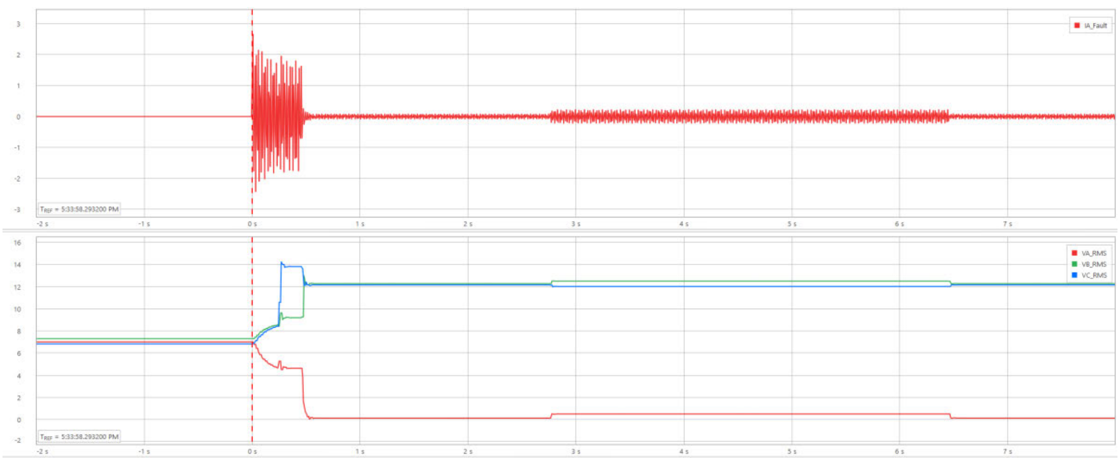


Figure 6 3200 ohm simulated fault

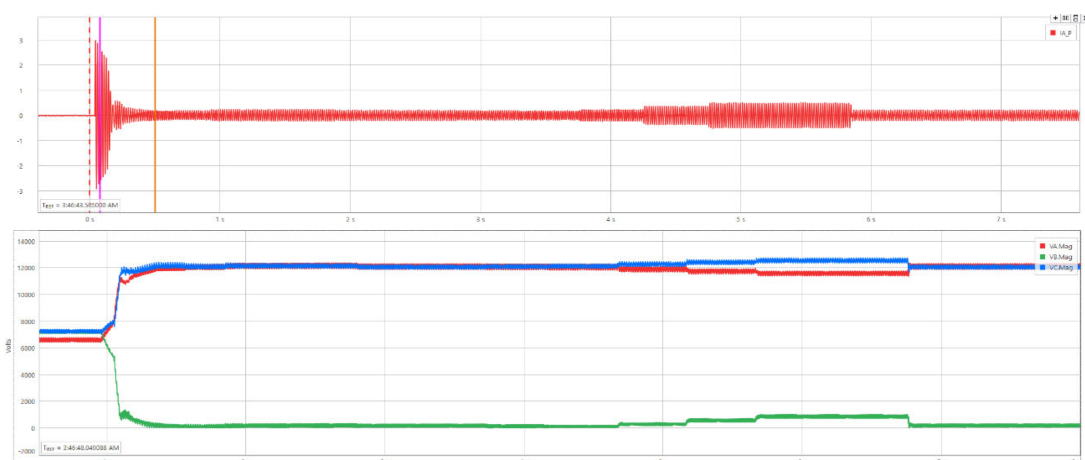


Figure 7 3200 ohm field staged fault

9.0 Distribution Operations

9.1 Training

9.1.1 Distribution Operations received training on how REFCL works and how to operate the equipment in the field for the demonstration. Videos, Technical Bulletins, and 5 Minute Meetings (5MM) were uploaded to the Distribution Operators Toolbox.

9.2 Demonstration

9.2.1 Controls of REFCL were developed in PG&E's distribution SCADA system. Operators were able to cut-in and cut-out the GFN for testing purposes. Screen shots of the SCADA views are in the Appendix.

9.2.2 The SEFM automation made it easier for operators to cut-in and cut-out the GFN by automatically changing the GFN mode based on the position of the Neutral/2 grounding recloser. The SEFM functions were set up to be deployed and tested at different stages of the demonstration.

9.2.3 Different settings groups were established to change the GFN sensitivity and operation based on the fire potential index. Settings Group 1 is for low fire potential index (R3 or below) and has a four second time delay before performing fault confirmation to eliminate trips from momentary faults. If the fault is permanent, the SEFM automatically cuts out the GFN and closes Neutral/2 to solidly ground the transformer bank for 60 seconds to allow for the protective devices to clear the fault (Figure 8).

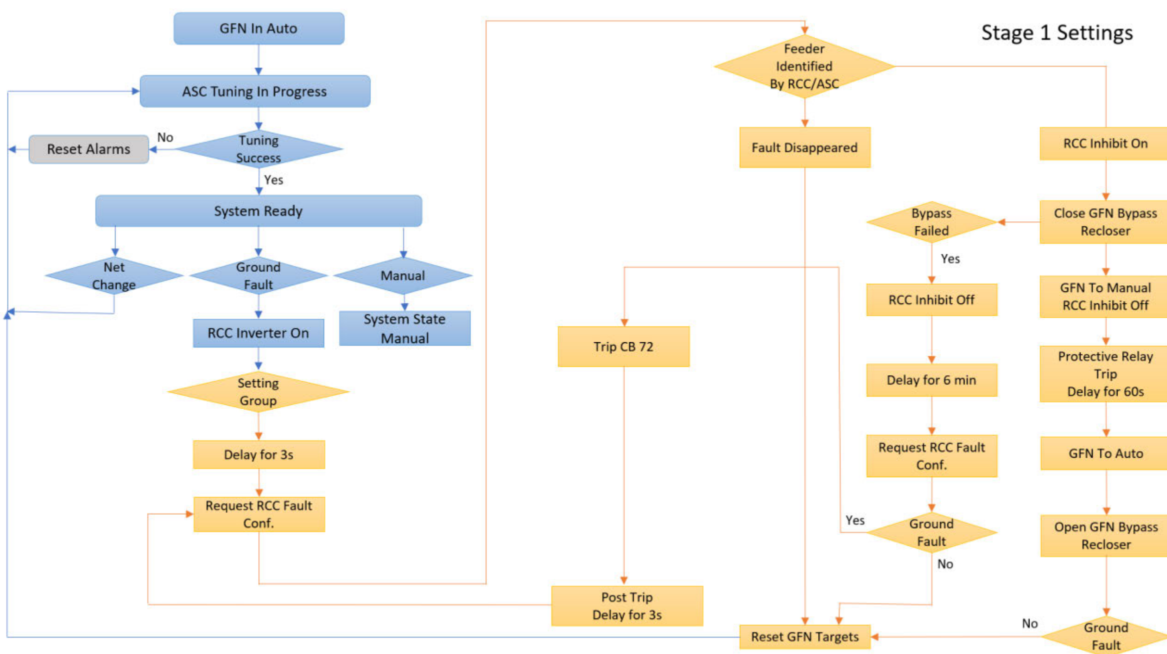


Figure 8 Settings Group 1 SEFM/GFN Operation

9.2.4 Settings Group 2 and 3 are for fire potential index R4 and above. Settings Group 2 is set up to incorporate the SEFM line recloser tripping algorithm to isolate the fault with the substation bank resonant grounded (Figure 9).

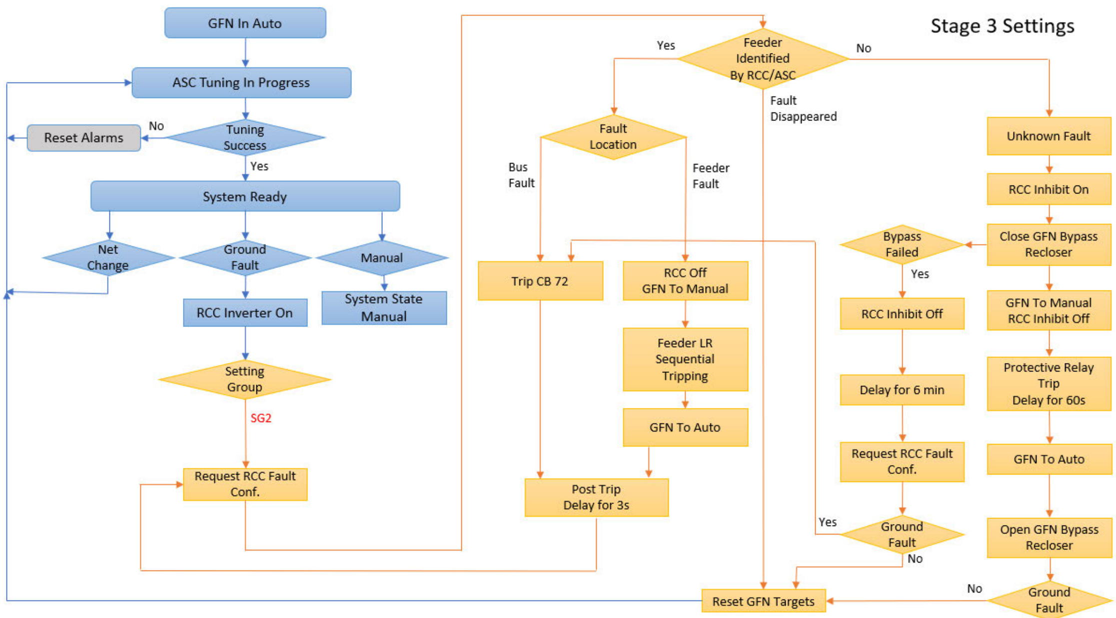


Figure 9 Settings Group 2 SEFM/GFN Operation

9.2.5 Settings Group 3 is for extreme fire risk days where the SEFM directly trips the feeder breaker immediately after the fault is detected and confirmed (Figure 10).

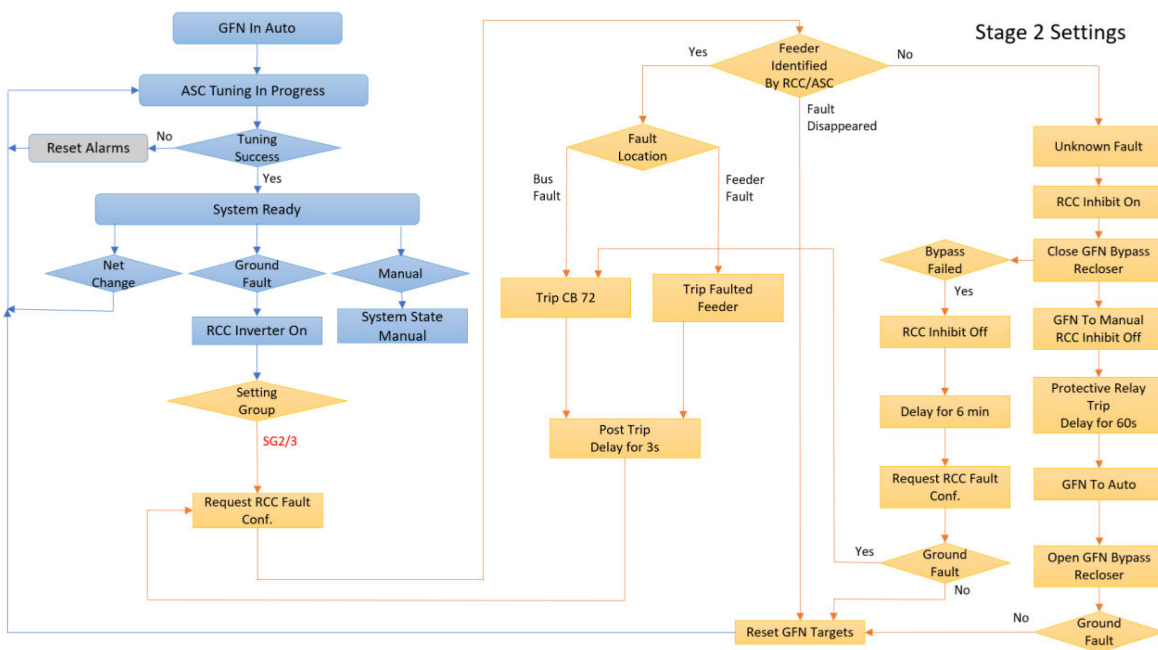


Figure 10 Settings Group 3 SEFM/GFN Operation

10.0 Field Testing

10.1.1 A custom mobile high voltage test resistor was built for field testing. The design was similar to the test trailers used in Australia.

10.1.2 The resistor bank allowed for staged fault tests with resistance in 100 ohm increments from 100 ohms up to 25,400 ohms.

10.1.3 The target for REFCL fault sensitivity was 14,000 ohms, corresponding to 0.5A of fault current per the Energy Safe Victoria standard (Figure 11).

REFCL Required Capacity

a) Reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone substation for high impedance faults to 250 volts within 2 seconds; and

b) Reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone substation for low impedance faults to —

(i) 1,900 volts within 85 milliseconds; and

(ii) 750 volts within 500 milliseconds; and

(iii) 250 volts within 2 seconds; and

c) During diagnostic tests for high impedance faults, limit —

(i) fault current to 0.5 amps or less; and

(ii) the thermal energy on the electric line to a maximum i^2t value of 0.1.

Figure 11 Energy Safe Victoria REFCL Capacity Standard [1]

10.1.4 One successful staged fault test was performed with fault resistance of 3,200 ohms (Figure 7). The steady state fault current was 0.08 Amps and i^2t was 0.03 A^2s, corresponding to a fault power of 20.5 W.

10.1.5 Testing was stopped after the first staged fault test to review the data and modify settings in the GFN. Unfortunately, the grounding transformer failed, so no further field testing was performed.

11.0 Challenges Encountered

11.1 General

11.1.1 The COVID-19 pandemic had substantial impact on the project, especially supply chain for key equipment needed for the implementation. The high voltage test trailer was delivered 5 months later than initially expected.

11.1.2 Swedish Neutral was unable to provide on-site commissioning support for the GFN, so they did their best to support remotely. It was very helpful for members of the project team to travel to Australia and the Swedish Neutral factory to become familiar with the commissioning and operation of the GFN.

11.2 Substation

11.2.1 Establishing a clearance for Calistoga substation was a challenge since the existing main tie to Silverado was capacity limited. The autotransformer bank was replaced to increase the capacity to 7 MVA and allowed nearly all customers to be offloaded at night for construction activities inside the substation.

11.2.2 A "shoofly" (Figure 12) was installed just outside the fence at Calistoga substation to provide an alternate path to the Calistoga distribution circuits and de-energize the 12 kV bus inside the station. The shoofly was a key part in maintaining reliable service to Calistoga.

Figure 12 Shoofly installed outside fence at Calistoga substation

11.2.3 **Substation Voltage Regulator Failure**

New 12 kV, 578Amp Type "A" voltage regulators were installed in a closed delta configuration. The substation service transformer was replaced with a new delta connected 12kV:120/240V one. While performing the substation test program for the new voltage regulators, the Phase A voltage regulator experienced a failure. The internal potential transformer (PT) failed (Figure 13).

Figure 13 Failed internal PT inside voltage regulator

11.2.4 The root cause of the failure was a ferro-resonance between the PT and the capacitance of the service transformer which was in a no load configuration. Ferro-resonance is difficult to anticipate, and after reviewing the equivalent circuit (Figure 14) and parameters, the step response to single phase switching was modeled and the PT experienced up to twice rated voltage, leading to its failure.

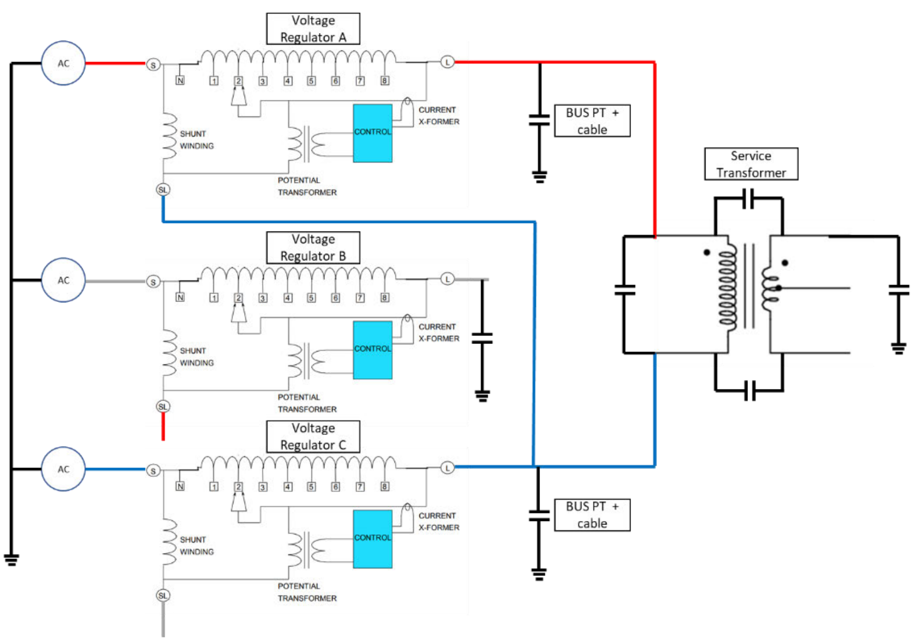


Figure 14 Equivalent circuit of ferro-resonance between voltage regulator and service transformer

11.2.5 To mitigate the ferro-resonance the service transformer was relocated to the source side of the delta connected voltage regulators, the regulators were replaced with Type “B” design, and the bus PT secondaries were closed before energizing the 12 kV bus.

11.2.6 **GFN RCC Inverter Failure**

As part of commissioning the GFN, an insulation stress test is performed where the neutral voltage is displaced 100% and held there for 6 minutes to increase the line to ground voltage of each phase. No distribution equipment failed or outages occurred as a result of the stress test.

During the RCC inverter calibration, a 160A L1 fuse in the GFN container blew (Figure 15) and a 10E fuse on Phase C on the riser supplying the GFN container at 12 kV supply blew. Inspection of the RCC showed it was damaged and needed to be replaced (Figure 16).

Figure 15 L1 fuse supplying RCC inverter blew

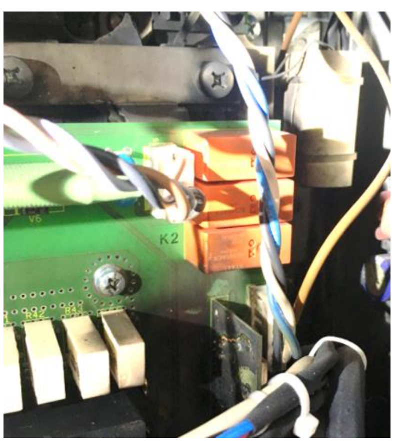


Figure 16 Burnt boards on RCC inverter

11.2.7 The other 12 kV equipment inside the GFN container was tested and determined to be OK. While attempting to energize the GFN container with the load disconnected from the 230/400V service, ferro-resonance with the grounding transformer occurred causing 25E fuses to blow each time when switched individually. The ferro-resonance equivalent circuit was developed and reviewed. Methods to avoid ferro-resonance were determined to be isolate the path with 3-phase tripping or eliminate the grounding transformer from the design.

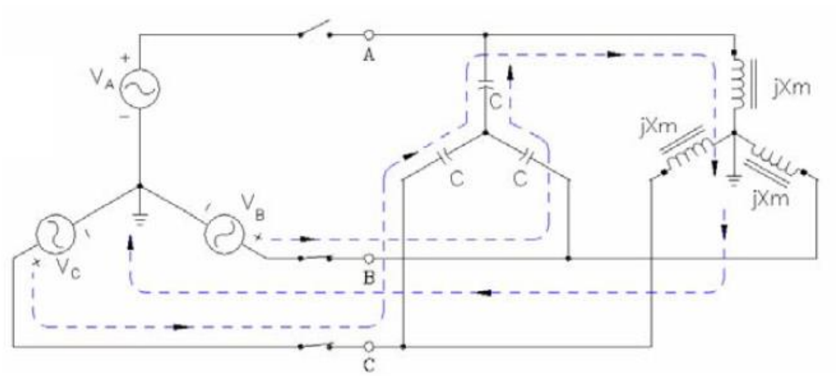


Figure 17 Equivalent Circuit for ferro-resonance of grounding transformer [2]

11.2.8 The ferro-resonance with the grounding transformed was mitigated by changing the fuses (Figure 18) to a 3-phase gang operated Viper recloser arrangement (Figure 19).

Figure 18 Fused cutouts on GFN riser

Figure 19 3-phase Viper recloser on GFN riser

11.2.9 Ultimately the grounding transformer HV insulation failed (power factor above 3%), resulting in a bolted ground fault and tripped the newly installed Viper recloser. The failure resulted in unsuccessful integration of the REFCL technology into PG&E's system as of July 2021.

11.3 Distribution

11.3.1 The Capacitor Balancing Units (CBU) were a new type of equipment. It took some feedback from field construction to make some improvements to the ground connections on the CBU cabinets. The grounding design using four or six extended ground rods worked well for achieving the expected performance from the CBUs.

The CBUs were set up from the supplier to reboot their radio every 24 hours. This caused problems for the FAN radios, so this functionality was turned off in a firmware update for the CBU. The CBUs ultimately were converted to communicate via cellular radios.

11.3.2 A misoperation was encountered for one of the distribution line voltage regulators. The regulator bank had been replaced with a multiphase CL7 controller. The CL7 controller lost accurate tracking of the tap position of each regulator unit, which resulted in a 4.5% voltage unbalance. The voltage unbalanced resulted in damage to some customer owned equipment. After Operations and the project team were notified, a DLT went out and synced all the regulator units back to neutral. The supplier of the controller recommended a setting adjustment for better tap position tracking. The recommended setting change was made to all the new CL7 controllers and the regulators performed as expected after that.

11.3.3 Generation from a primary customer on the 1102 circuit caused erratic voltage regulator behavior. At times the current would drop to less than 2 Amps, so the voltage regulator could not accurately determine the power flow direction. A settings change was made in the CL7 controller to operate in bias co-generation mode. If the power flow was between +/- 2%, the controller would do a test tap operation first to confirm the true power flow direction before fully tapping to adjust the voltage in band.

11.3.4 During high temperatures, high load unbalance was encountered (Figure 20) and the voltage regulators had to be temporarily changed to independent mode instead of locked step. This resulted in a neutral unbalance at the substation of 0.5 Amps. Distribution planning was engaged to determine a plan to correct the load unbalance (Figure 20).

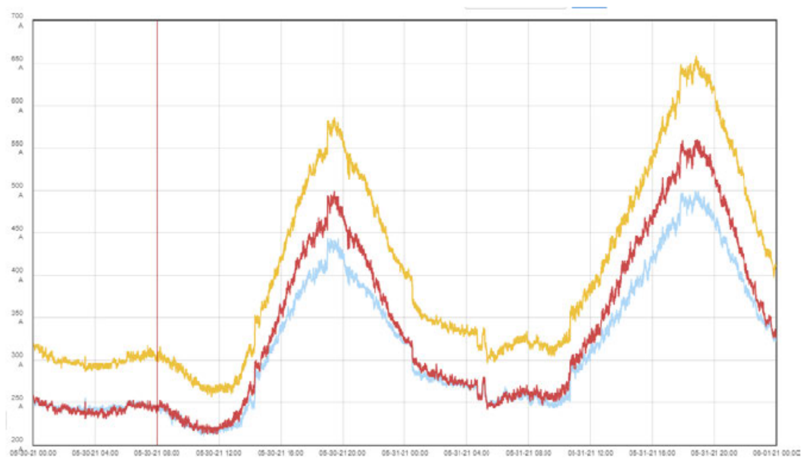


Figure 20 Summer peak load unbalance

12.0 Conclusion

In conclusion, the REFCL technology was successfully tested in one instance on a PG&E 12 kV distribution circuit and met the Energy Safe Victoria capacity standard. Unfortunately, equipment failures caused the full integration and operationalization to be unsuccessful as of July 2021. The project did not yet demonstrate that the technology could be successfully integrated with PG&E systems to inform the scalability of the technology for future deployments. The staged fault test showed that the technology worked to limit the fault current below 0.5 Amps, and PG&E is continuing to develop the integration of the REFCL technology.

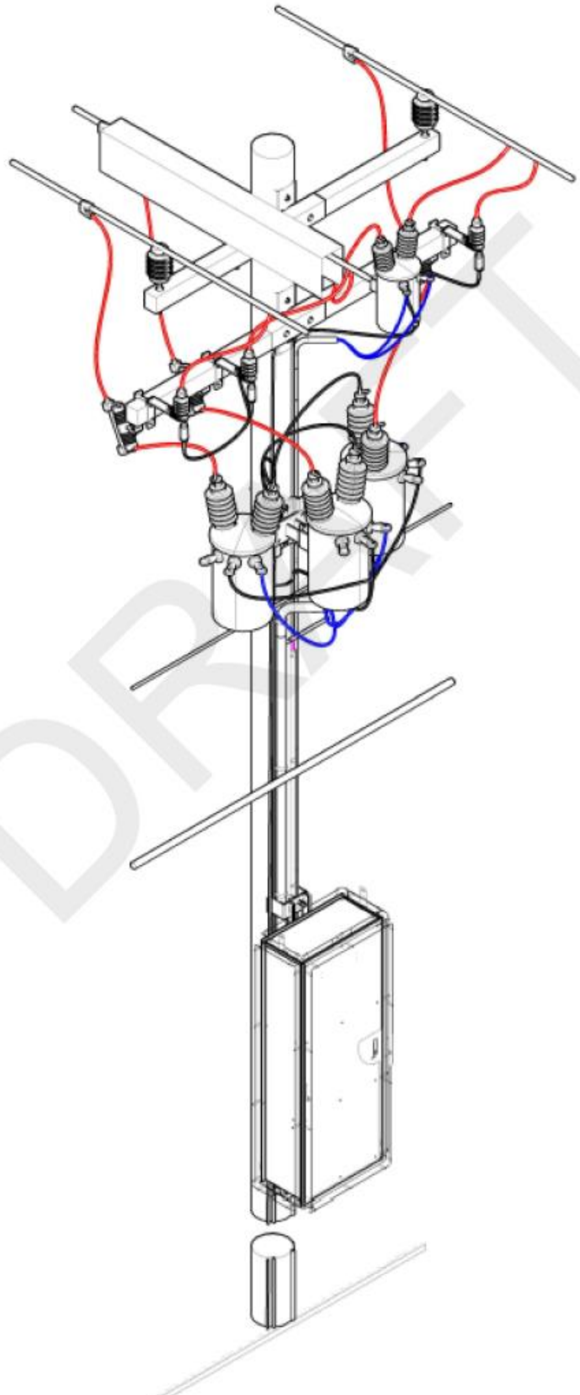
13.0 References

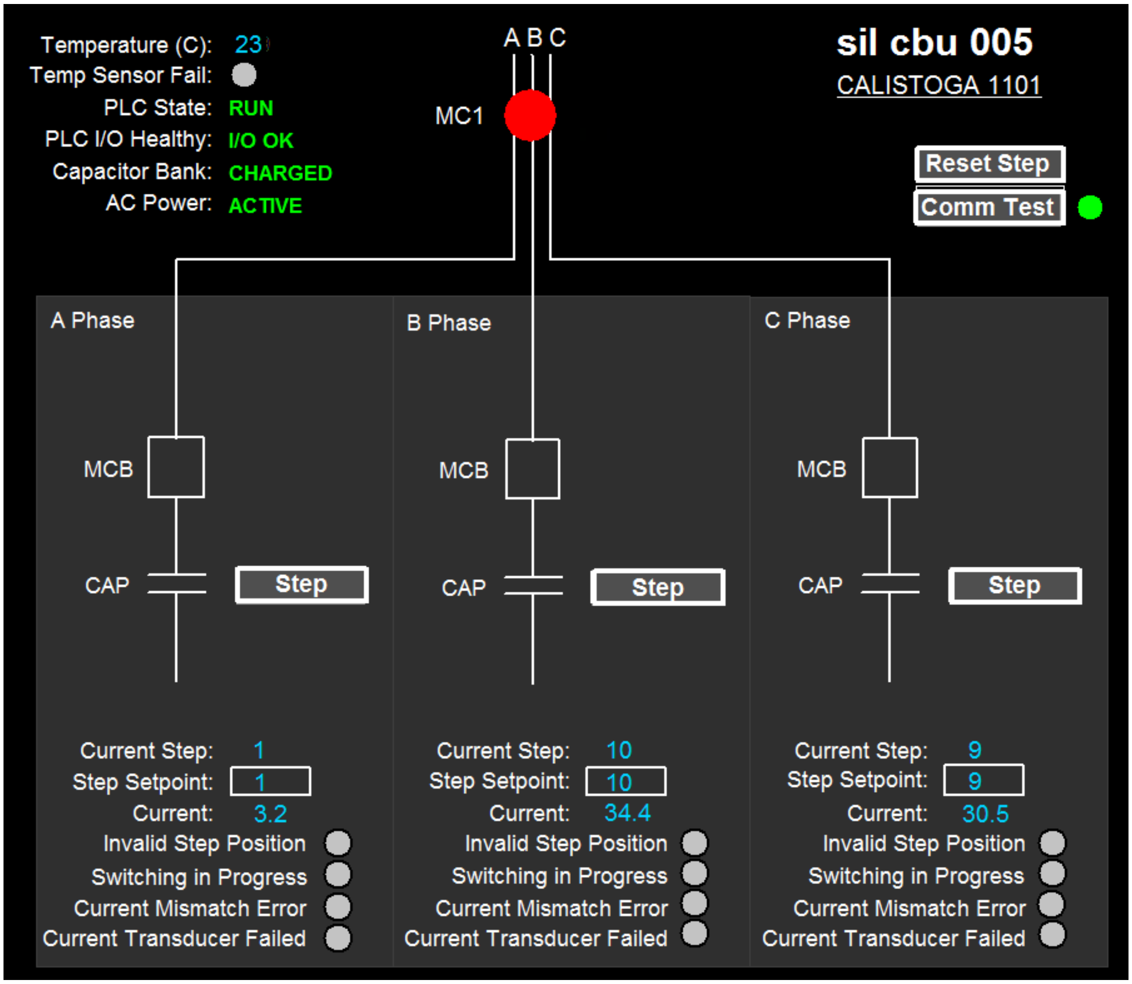
1. [redacted] "JA8648-0-0 REFCL Functional Performance Report." October 14, 2020. https://esv.vic.gov.au/pdfs/refcl-functional-performance-review/
2. Mork, Bruce A. "Understanding and Dealing with Ferroresonance." Minnesota Power Systems Conference. November 7, 2006.

14.0 Appendices

(continued)

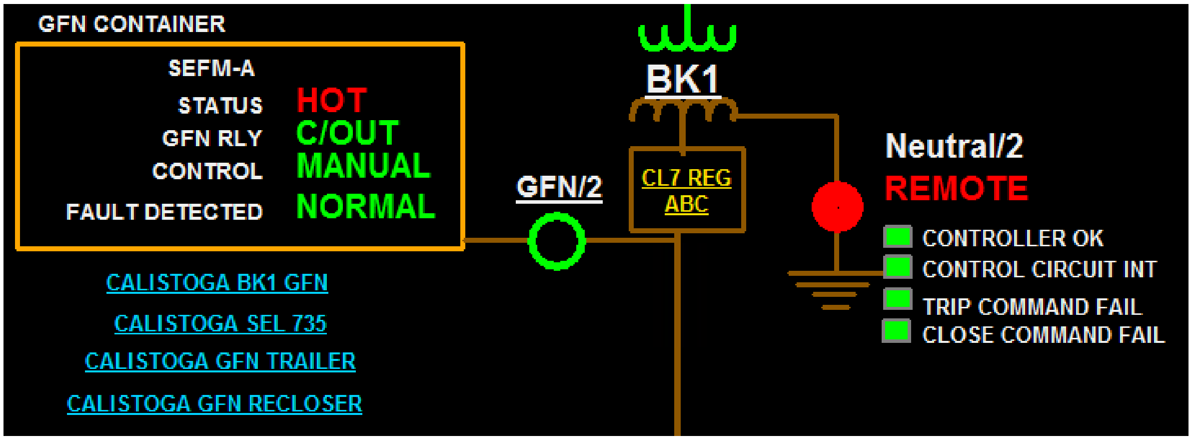
14.1 Appendix A – Capacitive Balancing Unit

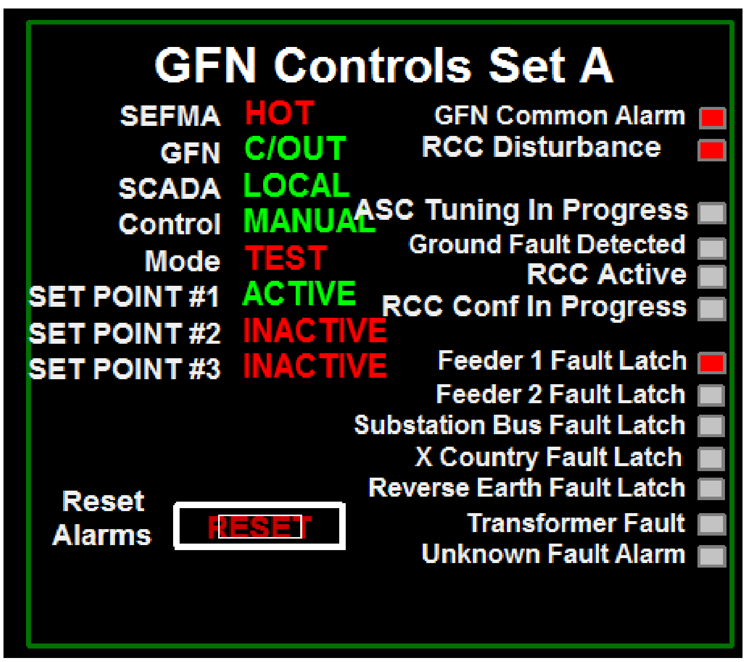


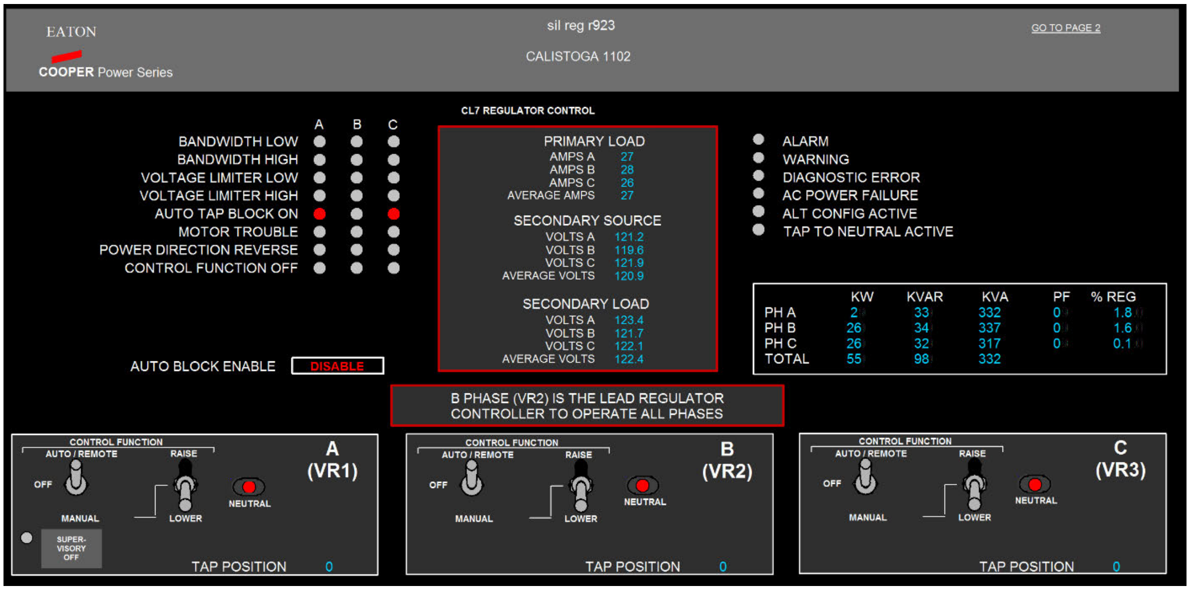


Temperature (C): 23
Temp Sensor Fail:
PLC State: RUN
PLC I/O Healthy: I/O OK
Capacitor Bank: CHARGED
AC Power: ACTIVE
A B C
MC1
sil cbu 005
CALISTOGA 1101
Reset Step
Comm Test
A Phase
MCB
CAP
Step
Current Step: 1
Step Setpoint: 1
Current: 3.2
Invalid Step Position
Switching in Progress
Current Mismatch Error
Current Transducer Failed
B Phase
MCB
CAP
Step
Current Step: 10
Step Setpoint: 10
Current: 34.4
Invalid Step Position
Switching in Progress
Current Mismatch Error
Current Transducer Failed
C Phase
MCB
CAP
Step
Current Step: 9
Step Setpoint: 9
Current: 30.5
Invalid Step Position
Switching in Progress
Current Mismatch Error
Current Transducer Failed

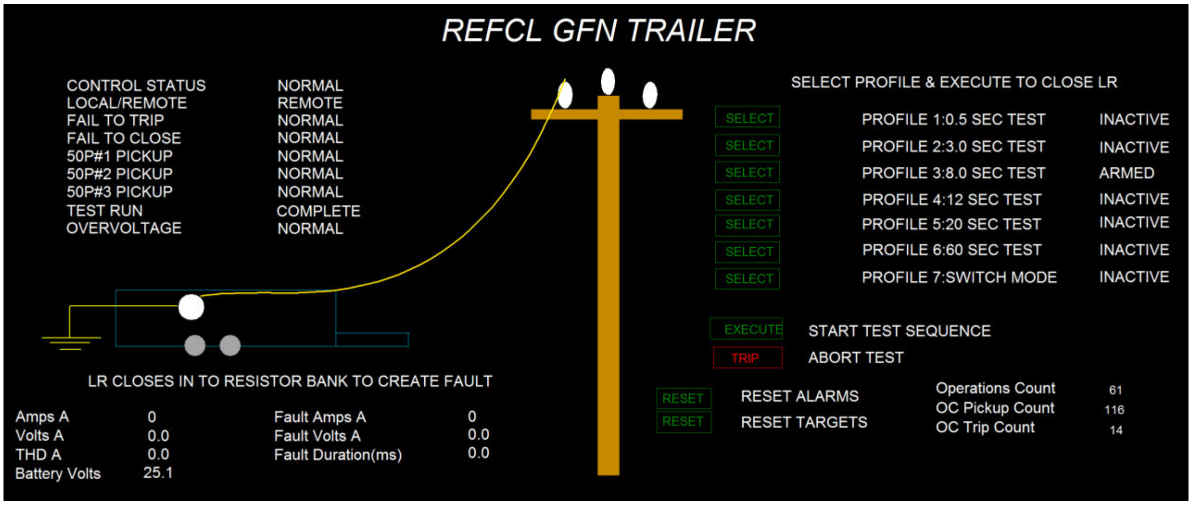
14.2 Appendix B – REFCL SCADA Views






EATON
COOPER Power Series
sil reg r923
CALISTOGA 1102
GO TO PAGE 2
CL7 REGULATOR CONTROL
A B C
BANDWIDTH LOW
BANDWIDTH HIGH
VOLTAGE LIMITER LOW
VOLTAGE LIMITER HIGH
AUTO TAP BLOCK ON
MOTOR TROUBLE
POWER DIRECTION REVERSE
CONTROL FUNCTION OFF
PRIMARY LOAD
AMPS A 27
AMPS B 28
AMPS C 26
AVERAGE AMPS 27
SECONDARY SOURCE
VOLTS A 121.2
VOLTS B 119.6
VOLTS C 121.9
AVERAGE VOLTS 120.9
SECONDARY LOAD
VOLTS A 123.4
VOLTS B 121.7
VOLTS C 122.1
AVERAGE VOLTS 122.4
ALARM
WARNING
DIAGNOSTIC ERROR
AC POWER FAILURE
ALT CONFIG ACTIVE
TAP TO NEUTRAL ACTIVE
KW KVAR KVA PF % REG
PH A 2 33 332 0 1.8
PH B 26 34 337 0 1.6
PH C 26 32 317 0 0.1
TOTAL 55 98 332
AUTO BLOCK ENABLE
DISABLE
B PHASE (VR2) IS THE LEAD REGULATOR
CONTROLLER TO OPERATE ALL PHASES
CONTROL FUNCTION
AUTO / REMOTE
OFF
MANUAL
RAISE
LOWER
NEUTRAL
A
(VR1)
SUPER-
VISORY
OFF
TAP POSITION 0
CONTROL FUNCTION
AUTO / REMOTE
OFF
MANUAL
RAISE
LOWER
NEUTRAL
B
(VR2)
TAP POSITION 0
CONTROL FUNCTION
AUTO / REMOTE
OFF
MANUAL
RAISE
LOWER
NEUTRAL
C
(VR3)
TAP POSITION 0

14.3 Appendix C – Mobile High Voltage Test Resistor


REFCL GFN TRAILER
CONTROL STATUS NORMAL
LOCAL/REMOTE REMOTE
FAIL TO TRIP NORMAL
FAIL TO CLOSE NORMAL
50P#1 PICKUP NORMAL
50P#2 PICKUP NORMAL
50P#3 PICKUP NORMAL
TEST RUN COMPLETE
OVERVOLTAGE NORMAL
LR CLOSES IN TO RESISTOR BANK TO CREATE FAULT
Amps A 0
Volts A 0.0
THD A 0.0
Battery Volts 25.1
Fault Amps A 0
Fault Volts A 0.0
Fault Duration(ms) 0.0
SELECT PROFILE & EXECUTE TO CLOSE LR
SELECT PROFILE 1:0.5 SEC TEST INACTIVE
SELECT PROFILE 2:3.0 SEC TEST INACTIVE
SELECT PROFILE 3:8.0 SEC TEST ARMED
SELECT PROFILE 4:12 SEC TEST INACTIVE
SELECT PROFILE 5:20 SEC TEST INACTIVE
SELECT PROFILE 6:60 SEC TEST INACTIVE
SELECT PROFILE 7:SWITCH MODE INACTIVE
EXECUTE START TEST SEQUENCE
TRIP ABORT TEST
RESET RESET ALARMS
RESET RESET TARGETS
Operations Count 61
OC Pickup Count 116
OC Trip Count 14

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