ABSTRACT

VUKOJEVIC, ALEKSANDAR. Design of Reliable and Secure System Protection and Control Schemes in Microgrids Consisting of Inverter-Based Distributed Energy Resources. (Under the direction of Dr. Srdjan Lukic).

In past few years, numerous weather events have caused significant outages to the electric power grid, resulting in billion dollars of damage. In order to increase customer reliability indices and reduce outage time, the emergence of distributed energy resources (DERs) and microgrids became major topic among numerous industry stakeholders. There are several main value propositions of this research that also have been tested, implemented and verified in the field within electric utility microgrid: the addition of grounding transformer to the microgrid in order to provide effective grounding, new method for the design of grounding transformer, new approach to the protection and control of the grounding transformer, new reliable and secure microgrid protection and control scheme and improvement of microgrid reliability and stability by designing the seamless islanding and grid synchronization control schemes.

Synchronous generators represent the most common type of DERs today. In recent years, most of the new installed generation came in form of renewables, such as PV systems, wind turbines and batteries (for storage). This research focuses on the design of effective grounding for microgrids with inverter-based DERs, development of new protection and control scheme for the microgrid as a whole and design of seamless islanding and grid synchronization control schemes. Inverter-based DERs do not provide large fault current levels, so typical overcurrent (50/51) schemes cannot adequately protect the microgrid in islanded state. Majority of the microgrid protection schemes today are based on the undervoltage (27), underfrequency (81U), overvoltage (59), and overfrequency (81O) elements. This research proposes new microgrid protection scheme that consists of voltage restrained element (51VR) torque-controlled by negative-sequence
impedance element ($Z_2$) and T32P as the primary protection element and rate of change of current sequence networks ($d3I_2/dt$ and $d3I_0/dt$) as additional protection element. In addition, in order to enable seamless islanding, this research proposes the new 85 RIO scheme (remote input/output) utilizing the serial communications over fiber based on mirror bits between the islanding switch (PCC) and battery energy storage system (BESS).

Inverter-based DERs are mostly ungrounded, so system protection design must include the implementation of grounding transformer, which presents additional challenges in form of unpredictable voltage sags/swells during the transition to and from island. Seamless transition, both intentional and unintentional, represents the most challenging task to accomplish, given that the BESS inverter changes three operating modes within 128ms, and without the proper design of system protection and control scheme and relay settings, microgrid will experience black-outs because of the sympathetic tripping. Since current IEEE Standards do not cover the design of effective grounding within the microgrid with inverter-based DERs, the paper proposes the new approach to the design of grounding transformer, which is simulations-based and includes both fault current and transient analysis, in order to ensure the effective grounding and the safety of the equipment and personnel. In addition, the paper also proposes the new protection and control scheme for grounding transformer that can identify both internal and external faults.
Design of Reliable and Secure System Protection and Control Schemes in Microgrids Consisting of Inverter-Based Distributed Energy Resources

by
Aleksandar Vukojevic

A dissertation submitted to the Graduate Faculty of North Carolina State University in partial fulfillment of the requirements for the degree of Doctor of Philosophy

Electrical Engineering

Raleigh, North Carolina

2020

APPROVED BY:

__________________________________________________________  __________________________________________
Dr. Srdjan Lukic  Dr. David Lubkeman
Committee Chair

__________________________________________________________  __________________________________________
Dr. Mesut Baran  Dr. Leonard White
DEDICATION

I would like to thank my advisor, Dr. Srdjan Lukic for his guidance throughout the PhD program. Throughout my journey, I learned how to find the right balance between the effort needed for power system analysis and simulations, analysis of the real response of the system after implementation and trying to understand the difference between the two.

I would also like to thank Dr. Leonard White for his support and guidance through my time at NCSU, as well as lessons that I learned listening to Dr. White draw on his immense practical experience.

I would like to thank Dr. Mesut Baran for his support and guidance, as I have learned a lot from Dr. Baran about system protection and control reading the numerous articles that Dr. Baran has published, as well as from our conversations.

I would also like to thank Dr. David Lubkeman for his support and guidance and knowledge that Dr. Lubkeman has shared with me.

Mostly, I would like to thank my parents (Radomir and Dragica (R.I.P)), who sacrificed everything that they have accomplished in our native country and moved to the US, so that my brother and me can have the opportunity to achieve our goals. Most importantly, I would also like to thank my children - Steven (4), Ava (9) and Adon (11), who made me laugh and smile throughout this journey, and made me fully understand what Carl Jung once said: “I am not what has happened to me…I am what I choose to become!”
BIOGRAPHY

Aleksandar Vukojevic was born in former Yugoslavia, where he graduated from Electrical Engineering High School “Nikola Tesla” in Belgrade with concentration in Power Systems. Following the move to the United States, Aleksandar graduated with Bachelor’s Degree in Applied Mathematics from Kennesaw State University (2001), Bachelor’s and Master’s Degree in Electrical Engineering from Georgia Institute of Technology (2003, and 2004 respectively), and Masters of Business Administration in Corporate Finance from Robinson College of Business at Georgia State University (2009).

In his career, Aleksandar worked as a system protection and control engineer at Baltimore Gas and Electric, substation field test engineer and transmission planning engineer for Georgia Power, lead engineer in Smart Projects New Product Integration group at General Electric, Manager of Smart Grid, Distribution Automation and Technology at Baltimore Gas and Electric, and Technology Development Manager for Duke Energy. Aleksandar’s duties involved designing system protection and controls schemes for transmission and distribution systems, development of relay settings and coordination, development and execution of substation field test plans, working on transmission and distribution system assets (transformers, breakers, CCVTs, capacitor banks), planning and operation of the transmission system, development, implementation and commissioning of Volt/VAR controls on the 1,200 feeder distribution system, testing of 50 new emerging and smart technologies, and transferring these technologies to the internal electric utility stakeholders. Aleksandar holds 15 patents and he is a registered Professional Engineer in the State of North Carolina. Aleksandar lives in Harrisburg, NC with his 3 children. In his spare time, Aleksandar rides bicycle, plays the guitar and basketball, and volunteers.
ACKNOWLEDGMENTS

The author would like to acknowledge the contribution of several individuals to the efforts associated with the field commissioning and testing of the electric utility’s microgrid where the actual implementation of the concepts and ideas presented in this document have been executed: Randy Brown, David Lawrence, Dwayne Bradley, and Rodney James from Duke Energy’s Emerging Technology Office, Michael Groomes and David Mulder from Open Energy Solutions, John Town, Andy Gould, Justin McDevitt, Matthew Shaw, and Andre Glover from SEL, and Howard Self and Javier Mendoza from ABB. The author would like to acknowledge the effort of Rona Vo and Lee Luis from SEL with respect to the Hardware-in-Loop verification testing of some of the concepts presented in the thesis.

The author would like to acknowledge the support of the leadership of the Emerging Technologies Office at Duke Energy, namely Jason Handley and Dr. Stuart Laval.

The author would also like to acknowledge the effort and conversations about the microgrid design, modelling, protection and control with Michael Ropp and Dustin Shultz from North Power Plains Technologies (NPPT).
TABLE OF CONTENTS

LIST OF TABLES .............................................................................................................. viii
LIST OF FIGURES ............................................................................................................ x

CHAPTER 1: Introduction .................................................................................................. 1
  1.1. Problem Statement ................................................................................................. 1
  1.2. Research Scope and Objectives .............................................................................. 2
  1.3. Chapter Outline ...................................................................................................... 3

CHAPTER 2: Microgrids – Background ........................................................................... 4
  2.1. Introduction ............................................................................................................ 4
  2.2. Distributed Energy Resources (DERs) .................................................................. 7
  2.3. Challenges with Inverter-based DER Integration ..................................................... 11
  2.4. Inverter-Based DERs Within the Microgrid ............................................................. 13
    2.4.1. Conventional vs. Inverter-Based Generation ..................................................... 13
    2.4.2. Inverter Operating Modes ................................................................................ 15

CHAPTER 3: Power System Grounding ............................................................................ 20

CHAPTER 4: Inverter-based DER Transformer Configuration ......................................... 28

CHAPTER 5: Grounding Transformer Design – New method ............................................. 34
  5.1. Grounding Transformer design using IEEE C62.92 and IEEE C57.32 Standards ...... 38
    5.1.1. Grounding Transformer Construction .............................................................. 39
    5.1.2. Voltage level .................................................................................................... 39
    5.1.3. Impedance (Z₀) ............................................................................................... 39
    5.1.4. Steady-state current ......................................................................................... 42
    5.1.5. Fault withstand neutral current ....................................................................... 43
    5.1.6. Fault current analysis ..................................................................................... 43
    5.1.7. Transient analysis ........................................................................................... 43
    5.1.8. kVA rating ....................................................................................................... 44
  5.2. Grounding Transformer design using IEEE 1547.8 Standard (Draft) .................... 44
    5.2.1. Grounding Transformer Construction .............................................................. 45
    5.2.2. Voltage level .................................................................................................... 45
    5.2.3. Impedance (Z₀) ............................................................................................... 45
    5.2.4. Steady-state current ......................................................................................... 46
    5.2.5. Fault withstand neutral current ....................................................................... 50
    5.2.6. Fault current analysis ..................................................................................... 51
7.7.2. $\Delta I_{1,2,0}/\Delta t$ P&C elements ................................................................................................. 179
7.7.3. Field testing – sequence-currents rate of change (di/dt) ........................................... 184
7.7.4. Conclusion – sequence-currents rate of change (di/dt) ............................................. 187

CHAPTER 8: Microgrid Protection and Control During Seamless Transition to Island and Grid Synchronization ........................................................................................................................................ 189
8.1. Seamless transition - background .................................................................................. 189
8.2. Seamless islanding ........................................................................................................ 193
  8.2.1. Frequency during seamless islanding transition ..................................................... 200
  8.2.2. Voltage during seamless islanding transition ......................................................... 203
  8.2.3. Islanding detection as a function of $P_L/P_G$ ratios ............................................. 208
8.3. Seamless grid synchronization ....................................................................................... 211
  8.3.1. Frequency during seamless grid synchronization .................................................. 211
  8.3.2. Voltage during seamless grid synchronization ....................................................... 212
8.4. Conclusion – seamless islanding and grid synchronization ....................................... 215

CHAPTER 9: Conclusions and Future Research ...................................................................... 216
REFERENCES ................................................................................................................................. 219
Table 45. BESS and Generator Islanding Operating Modes .............................................. 199
Table 46. 81U/81O settings for grid connected mode ...................................................... 201
Table 47. 81U/81O settings during the transition to island .............................................. 202
Table 48. 27/59 settings for grid connected mode .......................................................... 204
Table 49. 27/59 settings for transition mode ................................................................. 204
LIST OF FIGURES

Figure 1. Electric Utility Power System .................................................................................. 5
Figure 2. Microgrid Concept .................................................................................................... 5
Figure 3. Annual share of total U.S. electricity generation (1950 – 2016) ................................. 10
Figure 4. Grid powered by synchronous generators ................................................................. 14
Figure 5. Grid powered by synchronous generators and inverter-based DERs ....................... 15
Figure 6. Grid feeding inverter control mode (CSI-PQ) .......................................................... 16
Figure 7. Inverter as a “virtual generator” ................................................................................ 16
Figure 8. Current source grid supporting inverter control mode (VSI-PQ) ............................... 17
Figure 9. Voltage source grid supporting inverter control mode (VSI-V/f) ............................... 17
Figure 10. Frequency droop mode settings .............................................................................. 18
Figure 11. Voltage droop mode settings .................................................................................. 18
Figure 12. Grid forming inverter control mode (VSI-ISO) ......................................................... 19
Figure 13. Electric utility power system – independent grounding at each level ..................... 21
Figure 14. Transformer zero-sequence equivalent circuits ....................................................... 22
Figure 15. Effectively grounded system – independent grounding at each level ..................... 24
Figure 16. Distribution feeder with LG fault ............................................................................ 29
Figure 17. Feeder fault as seen from the substation – zero sequence ...................................... 30
Figure 18. Distribution feeder with LG fault and DER .............................................................. 30
Figure 19. LG fault on a feeder with Yg-Δ DER transformer .................................................. 31
Figure 20. Zero-sequence fault current as seen by the substation feeder relay ....................... 31
Figure 21. Zero-sequence fault current at the DER location .................................................. 32
Figure 22. Fault current seen by substation feeder relay with Yg-Y transformer at DER site .... 32
Figure 23. Microgrid one-line diagram ................................................................................... 38
Figure 24. Grounding transformer configurations ................................................................. 39
Figure 25. V_A0 vs. V_A0 for symmetrical 5% imbalance case as a function of x and y .......... 49
Figure 26. V_A0 vs. V_A0 for symmetrical 5% imbalance case as a function of the voltage angle . 49
Figure 27. Microgrid steady-state circulating current I_N ....................................................... 54
Figure 28. Microgrid unbalance current I_N – normal operating mode .................................. 57
Figure 29. LLG fault current as a function of grounding transformer kVA rating .................. 60
Figure 30. Un-faulted voltage V_B as a function of Z_0 ......................................................... 62
Figure 31. LG fault current as a function of Z_0 ................................................................. 63
Figure 32. LG fault response with changing fault resistance ................................................. 64
Figure 33. CoG as a function of Grounding Transformer Impedance ...................................... 65
Figure 34. CoG for the actual 75kVA, 150kVA, 300kVA and 500kVA grounding transformers 66
Figure 35. Open phase - BESS only ..................................................................................... 67
Figure 36. Open phase - BESS and Grounding transformer without load .............................. 68
Figure 37. Open phase - recloser single phase lockout .......................................................... 69
Figure 38. Backfeed voltage due to single-phase lockout ....................................................... 70
Figure 39. Grounding transformer – optimum feeder location .............................................. 70
Figure 40. Microgrid primary bus voltage after 10hp motor start .......................................... 73
Figure 41. Microgrid primary bus voltage after 10hp and 20hp motor start ............................ 74
Figure 42. Capacitor energization .......................................................................................... 75
Figure 43. Capacitor bank - restrike ...................................................................................... 76
Figure 44. Adjustable speed drive - rectifier circuit ............................................................... 78
<table>
<thead>
<tr>
<th>Figure</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>91</td>
<td>Symmetrical components of an unbalanced system</td>
</tr>
<tr>
<td>92</td>
<td>Sequence networks as a function of the fault type</td>
</tr>
<tr>
<td>93</td>
<td>BESS and PV – current sequence networks during LG fault</td>
</tr>
<tr>
<td>94</td>
<td>BESS &amp; PV – new protection and control scheme</td>
</tr>
<tr>
<td>95</td>
<td>BESS I₂ current – baseline vs. LG fault</td>
</tr>
<tr>
<td>96</td>
<td>PV I₂ current – baseline vs. LG fault</td>
</tr>
<tr>
<td>97</td>
<td>Breaker B3 sequence networks</td>
</tr>
<tr>
<td>98</td>
<td>LG fault - BESS and PV bus voltage - sequence networks</td>
</tr>
<tr>
<td>99</td>
<td>12.47kV V₁ voltage – baseline vs. LG fault</td>
</tr>
<tr>
<td>100</td>
<td>12.47kV V₂ voltage – baseline vs. LG fault</td>
</tr>
<tr>
<td>101</td>
<td>LG fault (phase A) on 480V bus at the customer load</td>
</tr>
<tr>
<td>102</td>
<td>Fault currents on the high side of 12.47kV – 277V/480V transformer</td>
</tr>
<tr>
<td>103</td>
<td>Sequence currents on the high side of 12.47kV – 277V/480V transformer</td>
</tr>
<tr>
<td>104</td>
<td>Microgrid yard showing the location of LG fault on 277V/480V</td>
</tr>
<tr>
<td>105</td>
<td>Microgrid one-line diagram – LG fault on 277V/480V side</td>
</tr>
<tr>
<td>106</td>
<td>Grounding transformer neutral current Iₙ</td>
</tr>
<tr>
<td>107</td>
<td>Voltage sequence networks during LG fault on 277V/480V side</td>
</tr>
<tr>
<td>108</td>
<td>1000kVA transformer high side fault current</td>
</tr>
<tr>
<td>109</td>
<td>Upstream recloser current sequence networks</td>
</tr>
<tr>
<td>110</td>
<td>BESS phase currents for LG fault on the transformer secondary</td>
</tr>
<tr>
<td>111</td>
<td>BESS sequence current network for LG fault on the transformer secondary</td>
</tr>
<tr>
<td>112</td>
<td>Voltage and current sequence network elements</td>
</tr>
<tr>
<td>113</td>
<td>L₁-L₂ fault on 120V/240V bus at the customer load</td>
</tr>
<tr>
<td>114</td>
<td>New recloser protection elements</td>
</tr>
<tr>
<td>115</td>
<td>Relay 51VR protection element - settings</td>
</tr>
<tr>
<td>116</td>
<td>Microgrid simulation – chronology</td>
</tr>
<tr>
<td>117</td>
<td>Microgrid line-to-line voltage during LG fault simulation</td>
</tr>
<tr>
<td>118</td>
<td>51VR voltage - settings</td>
</tr>
<tr>
<td>119</td>
<td>B₄ – fault currents</td>
</tr>
<tr>
<td>120</td>
<td>51VR element trip time - simulations</td>
</tr>
<tr>
<td>121</td>
<td>51VR element – I-V curve</td>
</tr>
<tr>
<td>122</td>
<td>Z₂ directional element - settings plane</td>
</tr>
<tr>
<td>123</td>
<td>51VR element torque-controlled by negative-sequence impedance element Z₂</td>
</tr>
<tr>
<td>124</td>
<td>51VR element – field relay TRIP time</td>
</tr>
<tr>
<td>125</td>
<td>51VR element – field data</td>
</tr>
<tr>
<td>126</td>
<td>B₂ breaker 51VR protection element using Z₂ element as a torque-control</td>
</tr>
<tr>
<td>127</td>
<td>Z₂ directional element – field results</td>
</tr>
<tr>
<td>128</td>
<td>51VR element TC by Z₂ - pickup-time</td>
</tr>
<tr>
<td>129</td>
<td>Z₂ element calculation used as a torque-control – pick-up times</td>
</tr>
<tr>
<td>130</td>
<td>Voltage sequence networks for LG fault</td>
</tr>
<tr>
<td>131</td>
<td>Relay Input Processing</td>
</tr>
<tr>
<td>132</td>
<td>Phase currents during microgrid LG fault</td>
</tr>
<tr>
<td>133</td>
<td>Butterworth filter</td>
</tr>
<tr>
<td>134</td>
<td>Rate of change of phase current - 60Hz signal response</td>
</tr>
<tr>
<td>135</td>
<td>Phase currents during microgrid LG fault</td>
</tr>
<tr>
<td>136</td>
<td>Negative-sequence current (3f₂) during microgrid LG fault</td>
</tr>
</tbody>
</table>
Figure 137. Zero-sequence current ($3I_0$) during microgrid LG fault ........................................... 181
Figure 138. Butterworth filter – order design ................................................................. 182
Figure 139. di/dt analysis during microgrid fault ................................................................. 183
Figure 140. di/dt – breaker B4 ......................................................................................... 184
Figure 141. di/dt - breaker B3 ......................................................................................... 185
Figure 142. HIL di/dt simulation - breaker B4 ................................................................. 187
Figure 143. HIL di/dt simulation - breaker B3 ................................................................. 187
Figure 144. Separation of protection and automation areas within the relay ............... 195
Figure 145. 85RIO Mirror bit communications between two devices ......................... 196
Figure 146. DI/DO module for interaction between PCC and BEES inverter ............... 196
Figure 147. Seamless islanding transition - algorithm ............................................... 197
Figure 148. Frequency response during transition to island for $P_I/P_G < 1$ ................ 201
Figure 149. Actual microgrid frequency response during transition to island .......... 202
Figure 150. Frequency settings during transition to island ............................................ 204
Figure 151. Voltage during successive transition to island ........................................... 205
Figure 152. Voltage during successive transition to island - actual ............................. 206
Figure 153. Voltage and neutral current during grounding transformer energization ... 207
Figure 154. Voltage settings during transition to island ............................................... 207
Figure 155. Islanding detection as a function of $P_I/P_G$ ratios ...................................... 209
Figure 156. Load shedding scheme - communication delays ....................................... 210
Figure 157. Seamless grid synchronization – algorithm ............................................. 211
Figure 158. Frequency response during grid synchronization .................................... 212
Figure 159. Frequency settings during transition to grid ............................................. 213
Figure 160. Voltage settings during transition to grid ............................................... 213
Figure 161. Voltage response during transition to grid .............................................. 214
CHAPTER 1: Introduction

1.1. Problem Statement

The main objective of a microgrid is to provide the power to the customer during an outage on the main feeder and to provide the ancillary services to the power system during the times when microgrid is grid-connected. According to the International Energy Agency (IEA), two-thirds of the new generation that came online during the 2016 has been in form of inverter-based renewables (photovoltaic (PV), wind, batteries, fuel cells, microturbines), and this trend has been continuing to go upwards. The largest percentage of renewable sources currently being installed is the PV.

In last few years, microgrids became increasingly more relevant, as numerous weather events, such as hurricanes on the east coast or wildfires on the west coast, started causing power outages resulting in hundreds of millions of dollars of damage and loss of human lives. Since microgrids require the source of power, inverter-based DERs started becoming the logical main option. But, how does one design, build, commission and operate a microgrid, consisting of inverter-based DERs, as part of the traditional grid, when the main grid itself was built for one-way power flow using synchronous generators as the main power source?

The research presented in this document examines the new design for effective grounding for the microgrid with inverter-based DERs, the new design of grounding transformer and its protection scheme, seamless islanding and grid synchronization of the microgrid, interaction and behavior of inverter-based DERs, such as PV and BESS and the new design of system protection and control schemes that enable secure and reliable microgrid operation, ensuring safe power delivery and islanded operation during the outage on the main feeder.
1.2. Research Scope and Objectives

The objective of this research is to design a generic microgrid with inverter-based DERs, and investigate and propose the following:

1. Design of effective grounding scheme for microgrid with inverter-based DERs,
2. Design of grounding transformer used to provide the effective grounding,
3. Design of protection and control scheme for grounding transformer,
4. Design of the new and improved system protection and control schemes that effectively replaces the traditional overcurrent protection, which in this case is rendered obsolete, and
5. Design of protection and control schemes that enable the fast, reliable and secure seamless transition (both intentional and unintentional) to island and grid re-synchronization.

The research presented in this paper has been done in three phases. The baseline for the whole research is a generic microgrid that is connected to the medium voltage (12.47kV) distribution feeder, consisting of inverter-based DERs, such as BESS and PV. First, a concept as it relates to the microgrid is introduced along with the background and research that has been completed and published up to date. Second, a novel idea is then introduced for each of the concepts that have been presented, along with relevant microgrid simulations that are carried out to prove the applicability of the implemented idea. Third, the idea is then implemented within the actual electric utility microgrid, after which measurements, status points and control points are recorded on both grid and microgrid side, and results are compared to simulations to determine if the novel idea has field merits and if the simulations are representative of what actually occurs within the electric utility microgrid. Results are provided for each of the concepts presented in this paper and conclusions were derived in order to compare the simulations and the actual microgrid field test results.
1.3. Chapter Outline

This document is organized as follows:

- Chapter 2 provides the basic background on microgrids, reasons for development, and literature review of inverter-based DERs,
- Chapter 3 provides the background on power system grounding and its relation to the microgrid grounding,
- Chapter 4 describes the inverter-based DER transformer design considerations when being connected to the electric utility’s distribution system,
- Chapter 5 explains the need for grounding transformer within the microgrid with inverter-based DERs and proposes the new design for the grounding transformer and compares it to the two,
- Chapter 6 proposes the new approach for the design of protection and control scheme for grounding transformer,
- Chapter 7 introduces the new microgrid protection and control strategies that enable the reliable and secure operation,
- Chapter 8 outlines the new control algorithms for seamless islanding and grid re-synchronization,
- Chapter 9 outlines the conclusions and the remaining research that needs to be completed.
CHAPTER 2: Microgrids – Background

2.1. Introduction

According to the United States Department of Energy (DOE) Microgrid Exchange Group, microgrid is defined as “a group of interconnected loads and distributed energy resources (DER) with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can connect and disconnect from the grid to enable it to operate in both grid-connected or islanded mode” [1]. For a system to be called a microgrid, the main requirement is to have a minimum of two DERs. Having simply a back-up generator does not constitute a microgrid. Typical electric utility system consists of three main parts: generation, transmission and distribution. Traditionally, the need for supplying the power to the increasing amount of load was satisfied by building large generation plants. Power is then transmitted over large distances through the transmission system. Near load centers, substations are built and transmission voltage levels (115kV – 765kV) are reduced to either sub-transmission voltage levels (34kV – 69kV) or distribution line levels (4kV – 25kV).

From distribution substation, feeders are built in order to deliver the power to end users or customers (residential, commercial and industrial). At the point of delivery, voltage levels are reduced using the transformers to different levels (120V – 600V). Figure 1 below shows typical electric utility power system [2]. In recent years, new generation that has been added to the grid has been mostly in form of renewables (PV, wind, battery). Unlike traditional generation plants, these DERs have been mostly connected to either sub-transmission or distribution feeders. Recent weather events that have caused significant prolonged outages to the US power grids, resulting in billions of dollars of damage, have also resulted in a new approach regarding the design, operation and implementation of DERs.
Integration of DERs, that can provide the resiliency and reliability to the end customers during the feeder outages, has created a new frenzy on the electric utility market in form of microgrids. One conceptual microgrid architecture [3] is shown on Figure 2 below.
The objective of microgrids is two-fold. First, microgrid can provide increased resiliency and reliability to end customers by operating in islanded mode when the main feeder experiences an outage. Second, when feeder operates normally and microgrid is connected to the feeder, DERs within the microgrid could operate in a different mode to provide benefits to both the customer and the grid. In grid-connected mode of operation, DERs could be controlled by the electric utility through the microgrid controller and provide ancillary services (voltage regulation, frequency regulation, capacity firming, and peak load shaving to name some).

There are two lines of distinction between the grid and microgrid. The first one is called point of interconnection (POI) and the second one is called point of common coupling (PCC). In both cases, the hardware device (for both POI and PCC) is typically medium voltage breaker or a recloser. POI is the device that separates the electric utility from the microgrid. Typically, electric utilities require their own POI device at the interconnection point with DER. POI is connected to the electric utility’s distribution SCADA system which enables the utility to control it. The requirement for the installation of POI is based on the size of DER. In cases when the microgrid is owned by the customer, there might be a need for additional device - PCC, that customer can have a full control over. This device is typically controlled by a separate controller (in most cases microgrid controller) and it is used as islanding switch. When PCC is closed, the microgrid is connected to the grid, and DERs within the microgrid can operate based on several different operating modes, which are the function of types of DERs within the microgrid and technical capabilities of the inverters. When PCC is open, the microgrid is islanded (i.e. isolated from the main grid), and DERs within the microgrid are the main source of power, voltage and frequency.
2.2. Distributed Energy Resources (DERs)

Typical DERs used in microgrids today are PV systems, batteries, flywheels, combined heat and power (CHP), wind turbines, generators, microturbines, fuel cells and others. Each of these DERs has its own energy source, method of operation and connection to the microgrid. PV systems use the sunlight as a fuel and based on the temperature and irradiance, the inverter provides the power to the grid at a desired power factor (most of PV inverters installed today can provide power factor up to 0.88 lead/lag; newer 4-quadrant inverters can provide reactive power up and above the rating of the PV inverter). PV systems are built only for one-way power flow: from the solar panels to the grid. Newest developments in the design of PV inverters allow for bi-directional power flow. If battery energy storage system (BESS) is integrated on the DC bus of the PV system, then this storage can capture the excess of kWh lost throughout the day due to the clipping and early morning/late evening times, and then discharge it later when the feeder is experiencing the peak kW consumption, thus effectively enabling the peak-shaving. If the weather forecast for the following day shows that the PV plant will produce low output, then using bi-directional PV inverter it is possible to charge the battery overnight, during the times when the energy price is low, and then discharge it throughout the day, when it is needed. PV inverters are voltage controlled current sources, so they only provide the power if there is another stable source of voltage and frequency. When connected to the grid, the grid is the main source. When PV is the part of microgrid, it requires different source of voltage/frequency.

Battery energy storage systems (BESS) are built for two-way power flow. BESS can operate both in current source and voltage source modes and are much more flexible than PV systems, not only because they can act as voltage/frequency source during the islanding, but
because they can provide several ancillary services, such as voltage regulation, frequency regulation, capacity firming, peak load shaving.

The flywheel energy storage (FES) is a device that stores rotational energy. Typically, energy is stored in a flywheel by increasing its rotational speed up to 16,000 rpm (new designs with high-strength carbon-fiber composites that are suspended by magnetic bearings can speed up to anywhere between 20,000 and 50,000 rpm in a vacuum enclosure) [4]. Then, the flywheel keeps its angular momentum until the force is applied (if no force is applied during the long period, the flywheel will slow down because the bearings that hold the flywheel have a friction force, and also as flywheel spins through the air, the air resistance or drag slows it down). Typically, when the flywheel reaches the angular speed of 8,000 rpm, additional energy needs to be applied to bring it up to 16,000 rpm. Flywheels have been used since 1950s in automotive industry (flywheel powered buses), rail vehicles (voltage regulation, energy storage during the regenerative breaking), UPS systems (combined with batteries in large data centers, they are used for load leveling), aircraft carriers (rapid release into electromagnetic aircraft launch system), etc. Regarding the implementation within the electric utility, FES are used as a short-term spinning reserve for momentary grid frequency regulation, balancing the sudden changes between the grid supply and demand, energy storage generated by the wind turbines during the off-peak periods or during the high wind speeds.

CHP is a DER that uses the power generating plant or heat engine in order to generate power and the heating/cooling from the fuel combustion. These plants recover the thermal energy that otherwise would have been wasted. Typically, the high heat temperature first drives the gas/steam turbine powered generator, which in turn results in the heat at low temperature that is used for water heating, space heating or cooling in absorption refrigerator. Today, most of the CHP
systems are field designed and assembled (even though few fully integrated packaged CHP systems do exist on the market). The main reason for this is the use of proprietary protocols by component manufacturers. In addition, CHP systems are new technology, so there are some reliability issues with both hardware and operational challenges. The biggest challenge represents the integration: several different AC/DC sources are needed in order to operate the controls and auxiliary devices in CHP system, use of mixed units (SI vs. British), many duplicate sensors need to be installed in order to get the information to the controller, and lack of interoperability between the controllers used by different manufacturers whose components are used in CHP build/design.

Synchronous generators (three-phase) are the largest energy converters in the world and they represent the primary source of all electrical energy that we consume today [5]. They convert the mechanical power output into electrical power that is then sent to the electrical grid. Even though these generators can be powered by coal, reciprocating engines, and water, in recent years, natural gas has been used as the primary fuel source for the new generation. In addition, old coal power plants that electric utilities have been retiring in order to reduce the gas emissions, are being converted to natural gas as the main fuel source. Microgrid islanding detection schemes are much more challenging and less reliable using the synchronous generator compared to BESS due to its slower governor response compared to the inverter response. Figure 3 below shows the annual share of total U.S. electricity generation since 1950 [6].

Microturbines use natural gas (for example) at 5psi, which is then internally boosted up to 75psi and this gas under the pressure is used to run the turbine, which can reach up to 94,000 rpm. The output of the turbine is AC, which is then connected to a three stage power electronics device (AC – DC, DC – DC and DC – AC) which allows the generator to operate without the need to be synchronized to the grid. In addition, microturbine as a byproduct releases exhaust heat, which can
then be used for either heating or cooling (using absorption chillers), therefore acting as a CHP system.

![Annual share of total U.S. electricity generation (1950 – 2016).](image)

Wind turbines are devices that convert the kinetic energy of the wind into electrical energy. They are typically installed in the areas with high wind power density, which represents the mean annual power available per square meter of swept area of wind turbine and is given for different heights. Maximum achievable output of the wind turbine is 59.3% of the kinetic energy flowing through the turbine. In addition to the requirement for constant wind, wind farms require a lot of area and a lot of capital in order to be installed and commissioned. There are two types of conversion that take place inside the wind turbine. First, wind blows into the wind rotor turbine, which is connected to the gearbox and this causes the rotation. Gearbox is connected to the generator, so the kinetic energy of the wind is converted into rotational energy that powers the generators. Generator is then connected to the full-scale power converter, which consists of AC-DC converter, DC bus and DC-AC inverter. The main objective of the power conversion is not only to provide the desired voltage and frequency, but also to ride through the large frequency deviations, ride through the system faults, and to minimize the negative effect of undesirable power quality events that wind turbine might cause. The output of this power converter is then connected
to the filter and then stepped up to the desired voltage level using the transformer. The P and Q of the transformer are then fed to the electrical grid. One of the biggest drawbacks to the wind as a resource is its intermittency, so the utility system operators must increase the amount of overall spinning reserves, which comes at a higher cost.

Fuel cells convert the chemical energy from a fuel to electricity. The reliability of the fuel cells is high since they have no moving parts and do not involve the combustion process. Fuel cells do not store fuel in themselves, and they typically rely on the external fuel storage unit. Typical efficiency of fuel cells is in 40% - 60%. If the wasted heat is used to heat the building, then the efficiency can reach 85%. The main advantage of fuel cell systems compared to PV, BESS, or wind is that fuel cells can run 24/7/365 with constant fuel supply (natural gas for example). The main disadvantages are sensitivity to the slight variations in voltage and high cost of deployment.

2.3. Challenges with Inverter-based DER Integration

Designing microgrid can cost $X dollars depending on its size and complexity. Building, construction, testing and commissioning of such microgrid can cost in range of $(10-100)X dollars. However, operating that same microgrid with the same reliability indices (such as SAIFI, SAIDI and CAIDI) as the feeder that microgrid is connected to is priceless. Why is that so?

Microgrids typically face numerous operational challenges associated with integration of different DERs within the microgrid and the way that microgrid protection and control systems are designed. Main challenges associated with designing microgrid protection and control are:

1. **Effective grounding** – this is probably the biggest challenge, because designing the scheme that provides effective grounding is instrumental, since safety of customers and equipment depend on the proper grounding design. When microgrid operates in grid-connected mode, effective grounding is provided by the substation Δ-Yg transformer. Once
PCC opens and microgrid is in islanded mode, grounding source is lost, so new grounding scheme must be designed and implemented,

2. **Bi-directional power flows** – depending on the size of DERs and time of the year, a reverse power flow on the feeder can lead to major protection and control issues, especially with relay coordination, fault current levels, voltage control associated with voltage regulators and flow patterns that might cause nuisance trips,

3. **Low inertia** – inverter based DERs have very low inertia, are mostly ungrounded and are not designed for the fault current to flow through them, which is completely different from the bulk power system which has many synchronous generators with large inertia that are effectively grounded. This represents a challenge, because conventional protection and control schemes cannot be utilized given that fault current levels can typically be within the normal operating range of DERs,

4. **System stability issues** – transition from grid to island and reconnecting back to the grid typically causes transient stability issues due to the inverter operating mode changes. Also, inverters inject harmonics into the system and compliance with IEEE 519 standard might become a challenge after several years of operation of DERs or high $9^\text{th}$ harmonic injected onto the distribution system might cause interference with phone land lines,

5. **Microgrid modelling challenges** – majority of the system protection and control settings and designs are based on the engineering transient analysis that is based on the models and controls for different DERs. Typically, electric utilities use software programs that do not include voltages lower than primary (12.47kV for example). Majority of the DER inverters AC ratings are in 300V-800V range and majority of the microgrid loads are in 120 – 480V$_{AC}$ range. So, modelling, transient analysis and designing secure and reliable system
protection and control scheme represent major challenges for typical electric utility, as this represents the major departure from the steady state fault analysis, which is the type of analysis that electric utility engineers mostly perform. In order to perform the necessary microgrid analysis, different software system(s) and models must be used. However, if the model of any of the control loops of the DER inverters is not accurate to a desired level, the transient analysis might not result in an accurate solution, and the protection and control settings that are based on this analysis might not be proper, which in turn will result in system nuisance trips and reduced reliability indices, and

6. **Reliability** – depending on type of DERs used within the microgrid, the reliability of the microgrid might be significantly less than the feeder that the microgrid is connected to.

### 2.4. Inverter-Based DERs Within the Microgrid

As stated before, inverter-based DERs represent major challenge for the design and implementation of reliable and secure microgrid given the lack of traditional rotational inertia. On another side, given the speed of response, inverter-based DERs offer more flexibility when it comes to operational capabilities compared to the traditional generation.

#### 2.4.1. Conventional vs. Inverter-Based Generation

Increased installation of inverter-based DERs, which represent majority of the new generation that is being added to the electric utility system, has caused electric utilities to start looking at these assets in a different way, as these generation source differ from the typical conventional generators. The basic difference is based on the fact that conventional synchronous generators are considered to be voltage sources, as they provide the voltage/frequency source for the system, as they are controlled by the excitation systems. The frequency of the power system is determined by how fast do the generators spin. Figure 4 shows simple representation of the electric
grid (green), where all generators (blue) act in unison to “spin” the generators at the same frequency of 60Hz [6]. The grid coupling of the generators (or synchronization) is represented by the chains.

In order for electric power system to be stable, it needs to have stable frequency (60Hz) and voltage as determined by ANSI C84.1 standard [7]. To maintain the system voltage/frequency during the power outages, system operators “keep” certain amount of operating reserves, which are typically divided into four general classes:

![Figure 4. Grid powered by synchronous generators.](image)

a. Frequency response reserves – large generators during the system wide disturbance will continue to spin to the inertia and will slow down the system rate of change of frequency. Frequency response, which is based on the response of the governor (device that senses the system frequency), which will detect this change and automatically adjust the operation in order to maintain the system frequency,

b. Regulating reserves – resources needed to correct local imbalances between supply and demand that resulted from a system wide disturbance,

c. Contingency spinning reserves – additional synchronized generators that can be quickly engaged to stabilize the system after system wide disturbance,
d. Non-spinning supplemental reserves – these reserves are used to provide the spare capacity in case of the second system wide disturbance.

System installation of inverter-based only DERs present several major challenges to power system integration, microgrid system protection and control. First, inverter-based DERs reduce the overall system inertia, given that they do not have the physical inertia like synchronous generators. This in turn reduces the voltage/frequency response. Grid powered by synchronous generators and inverter-based DERs below [6], shows the inverter-based DERs (grid) loosely coupled to the electrical grid and as seen from the figure, loose chains represent the slow response to the system wide grid disturbance.

![Diagram](image)

Figure 5. Grid powered by synchronous generators and inverter-based DERs.

Given that inverter-based DERs are mostly intermittent, the system requires additional regulating reserves in order to keep the system stability and reliability intact. Furthermore, inverter-based DERs cannot be used as spinning reserves due to their intermittency.

2.4.2. Inverter Operating Modes

Inverter controllers can operate in two basic operating modes: current source mode (CSI) and voltage source mode (VSI). CSI mode is represented as voltage controlled current source with high current impedance source to the grid. This mode shown on Figure 6 is also called grid feeding inverter operating mode.
The inverter controller takes real and reactive power setpoints (P, Q) from the microgrid controller, and provides very fast current output response. The user can also specify the positive and negative ramp rate for P and Q. The main benefits of CSI mode are the balanced individual phase outputs, regardless of the feeder conditions, faster response compared to VSI-PQ mode and minimum ripple current. The downside of the CSI operating mode is that it cannot be used to island the microgrid. PV systems operate exclusively in this mode regardless if they are connected to the grid or islanded, while BESS and microturbines can operate in this mode in both islanded and grid connected mode.

Unlike CSI mode, VSI mode represents a low voltage impedance source to the grid using “virtual generator” as voltage controlled current source with high current impedance source to the grid. Figure 7 represents the model of an inverter as “virtual generator”. As it translates to the inverter VSI mode, the real power control (P) is equivalent to the amount of fuel that is provided to the turbine (this could be gas or hydro).
If the frequency needs to be controlled, the governor is used to close the loop on the fuel control. Reactive power (Q) is controlled via the amount of magnetic field in the generator. If the voltage needs to be controlled, then AVR is used to close the loop on the field control.

Inverters in VSI mode can operate in three different variations: current source grid supporting mode or VSI-PQ mode (Figure 8), voltage source grid supporting mode or VSI-V/f mode (Figure 9) and grid forming mode or VSI-ISO mode (Figure 12).

![Figure 8. Current source grid supporting inverter control mode (VSI-PQ).](image1)

Voltage source grid supporting inverter control mode, or what is commonly known as VSI-V/f mode, is typically used in islanded operation when the DER with the inverter is not the largest unit used for forming the grid and is rather used for operation in parallel with other DERs. The set-points for this mode are frequency, frequency droop (%), voltage and voltage droop (%).

![Figure 9. Voltage source grid supporting inverter control mode (VSI-V/f).](image2)

For the all simulations associated with the results presented in this paper, the following set points are used as shown in Table 1.
Table 1. V/f droop set-points

<table>
<thead>
<tr>
<th>V/f</th>
<th>Setting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency - f</td>
<td>60Hz (1.0p.u.)</td>
</tr>
<tr>
<td>Δf</td>
<td>-0.1167 p.u. &amp; +0.0833 p.u.</td>
</tr>
<tr>
<td>Voltage - V</td>
<td>347V_{AC} (1.0 p.u.)</td>
</tr>
<tr>
<td>ΔV</td>
<td>±5%</td>
</tr>
</tbody>
</table>

Note that the voltage settings are function of the AC voltage on the inverter-based DERs. Implementation of these settings provides the BESS inverter operating curves on Figure 10 and Figure 11.

Figure 10. Frequency droop mode settings.

Figure 11. Voltage droop mode settings.

Grid forming inverter control mode, or what is commonly known as islanding mode (VSI-ISO), is typical mode of operation for inverters that can create voltage and frequency source for the normal microgrid operation. Both BESS and microturbine can operate in this control mode. Figure 12 shows the inverter model in VSI-ISO mode.
Figure 12. Grid forming inverter control mode (VSI-ISO).

Typical user defined set points are desired voltage and frequency. For the purpose of the modelling, the set points are shown in Table 2 below.

Table 2. VSI-ISO set-points

<table>
<thead>
<tr>
<th>V/f</th>
<th>Setting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency - f</td>
<td>1.0 p.u.</td>
</tr>
<tr>
<td>Voltage - V</td>
<td>1.0 p.u.</td>
</tr>
</tbody>
</table>
CHAPTER 3: Power System Grounding

The main purpose of electrical system grounding is to provide the low impedance path between the neutral of the power system and earth. Power system grounding design has major impact on the operation of the power system as a whole and the safety of the personnel and end customers. For that reason, when designing the grounding scheme for the power system, there are five basic factors that are typically considered [8]:

1. Voltage ratings and degree of surge-voltage protection available from surge arresters,
2. Limitation of transient line-to-ground overvoltages,
3. Security (relays should not trip when there is no fault on the feeder, in order to avoid nuisance tripping) and reliability (relays should trip when they detect the fault) of the ground-fault relay protective schemes,
4. Ground fault magnitude current limitation, and
5. Safety.

There are two requirements that must be met for the transformer in order for it to provide the system ground, which are described in [9]. First, transformer winding on the voltage level where the ground is required must be connected in Y, where the neutral is connected to the earth. Second requirement, which is slightly more challenging to understand, requires that “the impedance of the transformer to ground fault current must be significantly lower than the impedance of the connection between the neutral and earth such that this neutral impedance governs the selection grounding mode” [9]. As a result, the only winding on the opposite side of Y that satisfies this requirement is Δ. In addition, Zig-Zag transformer configuration also provides the neutral point that can be grounded. Figure 13 shows the electrical power system and its grounding. Power system consists of three different parts: generation, transmission and distribution. As can be seen from the
figure, every part of the electric utility’s power system is grounded from Yg side of Δ–Yg transformer.

![Diagram of electric utility power system]

Figure 13. Electric utility power system – independent grounding at each level.

Distribution system grounding is also derived from the Δ-Yg transformer, where Yg side provides the effective grounding with its neutral being either solidly connected to the ground or using the resistor or inductance (other grounding methods include resonance, capacitance, neutral grounding equipment). Note that in some cases, this transformer can also be in Yg-Δ-Yg configuration. Impedance in this case is usually inserted between the neutral and grounding on the Yg side of the transformer, when there is a need to reduce the magnitude of the ground fault current. As impedance is inserted, the overall zero-sequence impedance $Z_0$ increases, therefore resulting in the lower ground fault current. From substation, approximately every two or three poles, neutral wire is grounded throughout the distribution feeder in order to prevent the voltage rise on the system neutral. One of the biggest misconceptions of the grounding in general is that every transformer that has Yg connection provides the system grounding, which is incorrect. In order to understand this phenomenon, it is necessary to understand the equivalent zero-sequence impedance of different transformer configurations, which are shown on Figure 14. As seen from this figure, only Yg–Δ configuration (both with and without the neutral impedance) has both high impedance to the balanced three phase voltages, so that when the system operates in normal mode, only small magnetizing current flows through the generator, and it also provides the very low impedance to zero-sequence voltages that would allow for high ground fault current to flow.
When microgrid is connected to the distribution feeder, its grounding is provided by the secondary (Yg) side of substation transformer. When PCC opens, the microgrid (with inverter-based DERs) becomes isolated from the feeder, and it loses its grounding source. Since all equipment within the microgrid is rated for the effectively grounded system, the first design objective for any microgrid becomes the design of effective grounding (note that there is additional section later on in this research paper covering the proper DER transformer configuration, because it can significantly impact the grounding and system protection and control scheme).

There are several IEEE standards that reference the neutral grounding of electrical utility systems. [9] provides the grounding design standard for industrial and commercial power systems (which are typically secondary power systems), but it does not provide any discussion with respect to the Coefficient of Grounding (CoG). [10] provides the grounding transformer design parameters, but it does not explicitly provide the design method. [11] provides the application of neutral grounding on distribution feeders with current-regulated and power-regulated inverter-based DERs, but the standard defers to [11] and [8], which outlines the procedure for designing the grounding transformer on the distribution system. However, this standard does not explicitly provide the procedure for the design of the grounding transformer operating as part of the microgrid in islanded mode with inverter-based DERs. Based on the review of the existing
standards as outlined above, today, there is no specific procedure that outlines the design of grounding transformer for microgrids with inverter-based DERs operating in islanded mode. Rather, the design for that grounding transformer reverts back to the traditional approach, which can result in oversized and over-engineered solution, which has negative impact on the operation of microgrid in islanded mode, as measured by the power quality indices, such as voltage sags, flicker $P_{li}$ and $P_{st}$ and Rapid Voltage Change (RVC). For that reason, this research paper introduces (later in this chapter) the new methodology for designing the microgrid grounding transformer operating in islanded mode. This is a completely new, simulations-based approach, which is different than the exiting calculations-based approach.

Before effective grounding can be designed form the microgrid, the term first needs to be defined. IEEE has published a complete standard [10] that covers the terminology, requirements and test procedures are they pertain to the neutral grounding equipment. As defined in [12], "grounded system is a system in which at least one conductor (usually neutral point of a transformer or generator winding) is intentionally connected to ground either directly or through an impedance”. Coefficient of Grounding or CoG is defined as the ratio $E_{LG}/E_{LL}$ (expressed as a percentage), or the highest root-mean-square (RMS) value of line-to-ground power-frequency voltage $E_{LG}$ on a non-faulted phase, at a particular location, during the line-to-ground fault affecting one or more phases, to the line-to-line power-frequency voltage $E_{LL}$ that would be obtained at the same particular location, if line-to-ground fault did not exist. Power system is considered to be effectively grounded if it is connected to the ground through an impedance such that the CoG is less than 0.8 (does not exceed 80%). What this means is if the system operates in normal state, and there is a phase A to ground fault, its voltage will decrease and voltages on the two non-faulted phases B and C will increase. For effectively grounded power system, phase voltages $V_B$ and $V_C$
should not exceed $0.8\sqrt{3}$ or 1.38p.u. level. Based on the power system simulations and calculations, this condition is obtained when $0 < X_0/X_1 < 3$ and $0 < R_0/X_1 < 1$ [12], [13]. Alternately, non-effectively grounded system is any system with CoG greater than 80%. Figure 15. shows the response of the effectively grounded system during LG fault.

![Figure 15. Effectively grounded system – response during LG fault.](image)

So, how is grounding bank designed traditionally? This approach is a very important to understand, because the same approach will be used to design the grounding transformer for the microgrid with inverter-based DERs later on in the paper, and the validity of this approach will be evaluated. The following example showing the design of grounding bank is taken from [11]. Assume that the distribution substation is ungrounded (which is similar to microgrid transitioning to the island mode by opening the PCC) on 34.5kV and that the three-phase fault duty at the substation is 525MVA.

The substation is to be grounded using a grounding transformer ($Y_g-\Delta$ or Zig-Zag) and the ground fault current needs to be limited to 5500A. Using $S_B = 100\ MVA$ and $V_B = 34.5kV$, we can calculate the base impedance and current as:
\[ Z_{BASE} = \frac{V_{DER}^2}{S_{DER}} = \frac{34.5kV^2}{100MVA} = 11.9\Omega \]
\[ I_{BASE} = \frac{S_{DER}}{\sqrt{3} \cdot V_{DER}} = \frac{100MVA}{\sqrt{3} \cdot 34.5kV} = 1673A \]

Positive \((Z_1)\) and negative \((Z_2)\) sequence impedance can be calculated as a function of the three-phase fault duty:

\[ Z_1 = Z_2 = \frac{S_{DER}}{S_{FAULT\ DUTY}} = \frac{100MVA}{525MVA} = 0.19\ p.u. \]

Ground fault current in per-unit value \(I_{GF}[p.u.]\) is calculated as:

\[ I_{GF}[p.u.] = \frac{I_{GF}}{I_{BASE}} = \frac{5500A}{1673A} = 3.29p.u. \]

Per-unit zero-sequence current \(I_0[p.u.]\) and actual zero-sequence current \(I_0[A]\) are then calculated as:

\[ I_0[p.u.] = \frac{I_{GF}[p.u.]}{3} = \frac{3.29p.u.}{3} = 1.10p.u. \]
\[ I_0[A] = I_{BASE} \cdot I_0[p.u.] = 1673A \cdot 1.10p.u. = 1840.3A \]

Total per-unit impedance \(Z_{TOTAL}[p.u.]\) of the grounding transformer is calculated as:

\[ Z_{TOTAL}[p.u.] = \frac{V[p.u.]}{I_0[p.u.]} = \frac{1.0p.u.}{1.10p.u.} = 0.913p.u. \]

Total impedance of grounding transformer is equal to the sum of individual sequence impedances \((Z_{TOTAL} = Z_1 + Z_2 + Z_0)\). From here, zero-sequence impedance \(Z_0[p.u.]\) can be calculated as:

\[ Z_0[p.u.] = Z_{TOTAL}[p.u.] - Z_1[p.u.] - Z_2[p.u.] = 0.913p.u. - 0.19p.u. - 0.19p.u. = 0.533p.u. \]

Converting p.u. value into \(\Omega\) value, we get that the zero-sequence impedance of the transformer \(Z_0[\Omega]\) is:

\[ Z_0[\Omega] = Z_{BASE} \cdot Z_0[p.u.] = 11.9\Omega \cdot 0.533p.u. = 6.3\Omega/\text{phase} \]
Yg–Δ grounding transformer provides only path for zero-sequence current and has no load most of the time, so it’s positive- and negative-sequence networks are open circuits. The short-time kVA rating is calculated then as:

\[ kVA = \frac{V_{LL} \times I_N}{\sqrt{3}} = \frac{34.5kV \times 5500A}{\sqrt{3}} = 110MVA \]

The Zig-Zag transformer has both windings connected to the primary 34.5kVA circuit. For that reason, short time kVA rating is calculated as:

\[ kVA = \frac{V_{LL} \times I_N}{3} = \frac{34.5kV \times 5500A}{3} = 63.25MVA \]

Since fault is expected to be cleared fast, grounding transformer are designed to carry the calculated ground fault current only for 10 seconds. Because of this reason, grounding transformers are significantly smaller in size compared to the transformers that are designed to carry the same kVA rating continuously. The example above places no limitations on the maximum acceptable earth fault factor (EFF). EFF is defined as ”at a given location of a three-phase system and for a given system configuration, the ratio of the highest RMS phase-to-earth power-frequency voltage on a healthy phase during a fault to earth affecting one or more phases at any point on the system to the RMS value of phase-to-earth power-frequency voltage which would be obtained at the given location in the absence of any such fault” in [14]. Based on the results of the analysis as described above, ratio of negative-sequence impedance to positive-sequence impedance is:

\[ \frac{X_0[p.u.]}{X_1[p.u.]} = \frac{0.533p.u.}{0.190p.u.} = 2.8 \]

Using Figure A.2 in [5], and assuming the effective grounding, resulting CoG is approximately 0.75 with \( R_0/X_1 = 1 \). From here, EFF is \( 0.75 \times \sqrt{3} = 1.30 \).

If the system is multi-grounded neutral system, it is desirable to have a resulting temporary overvoltage to be 120% or less. Note that distribution feeder relays typically have two overvoltage
(59) settings - the first level setting is most commonly 1.1p.u. with 2 seconds time delay and second level setting is most commonly 1.2p.u. with 5 or 10 cycles time delay. If the temporary overvoltage exceeds 120%, the relays will TRIP the breakers/reclosers, and this will result in a feeder outage. Using the maximum allowable overvoltage value of 20% (which effectively means that the CoG = 0.70) and Figure A.2 in [12], resulting $X_0/X_1$ is approximately 2.0. From here $X_0 = 2.0 \times 0.190p.u. = 0.38p.u.$ Grounding bank impedance ($Z_0[\Omega]$) now is:

$$Z_0[\Omega] = Z_{BASE} \times Z_0[p.u.] = 11.9\Omega \times 0.38 = 4.5\Omega/\text{phase}$$

Maximum ground fault current is then calculated as:

$$I_{GF}[p.u.] = \frac{3 \times I_{BASE}}{Z_1 + Z_2 + Z_0} = \frac{3 \times 1673A}{0.19 + 0.19 + 0.38} = 6600A$$

As a function of the new maximum ground fault value, short-term kVA rating of the grounding transformer will need to be increased for both $Yg - \Delta$ and a Zig-Zag transformer:

$$kVA = \frac{V_{LL} \times I_N}{\sqrt{3}} = \frac{34.5kV \times 6600A}{\sqrt{3}} = 131.466MVA$$

The Zig-Zag transformer has both windings connected to the primary 34.5kVA circuit. For that reason, short time kVA rating is calculated as:

$$kVA = \frac{V_{LL} \times I_N}{3} = \frac{34.5kV \times 6600A}{3} = 63.25MVA$$

Material presented in chapter presents the traditional calculations-based design of the effective grounding. However, this approach cannot be implemented when it comes to the design of effective grounding within the microgrid with inverter-based DERs.
CHAPTER 4: Inverter-based DER Transformer Configuration

In order to properly design the microgrid grounding, it is necessary to understand the impact of the DER transformer configuration on the faults during both grid-connected and islanded mode. Inverter-based DERs AC output is typically in 300-800V\textsubscript{AC} range, depending on the vendor and operational characteristics of the DC side source. So, in order to connect the inverter to the electric power system is it necessary to use the transformer. There are five commonly used transformer connections [15] as shown in Table 3 below:

<table>
<thead>
<tr>
<th>High Voltage</th>
<th>Low Voltage</th>
<th>Problems</th>
<th>Advantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Δ</td>
<td>Δ</td>
<td>Can supply the feeder circuit from ungrounded source after substation breaker trips</td>
<td>Provides no ground fault back-feed for upstream fault; no ground current from substation for a fault within the microgrid</td>
</tr>
<tr>
<td>Δ</td>
<td>Yg</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Yg</td>
<td>Δ</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Yg</td>
<td>Δ</td>
<td>Provides undesired ground current for upstream faults</td>
<td>No ground current from substation for microgrid faults</td>
</tr>
<tr>
<td>Yg</td>
<td>Yg</td>
<td>Feeder at the substation can trip for faults in microgrid</td>
<td>No overvoltage for upstream, ground fault if DER neutral is connected with low-impedance resistor</td>
</tr>
</tbody>
</table>

In doing the research and background literature on microgrids, and reviewing numerous technical papers, presentations, publications, MS thesis, PhD thesis and microgrid field implementations, there were three major design flaws that were discovered to be common for majority of the reviewed literature:

1. Transformer connections for inverter based DERs were mostly Yg – Δ, with Δ side of the transformer being connected to the AC side of the DER inverter and Yg side being connected to the distribution system,

2. Microgrid design with PV systems as the only DERs within the microgrid,

3. Grounding transformer was never included in the microgrid design.
These three microgrid design flaws are detrimental for the successful, reliable and secure microgrid design, and the reason for these flaws lies in lack of understanding of protection and control, fault sequence networks, effective grounding and proper inverter control schemes.

In order to prove that inverter-based DER should not be connected to the effectively grounded distribution feeder using Yg – Δ DER transformer configuration, first assume that we have a distribution feeder as shown on the Figure 16 along with the equivalent symmetrical component circuit.

Figure 16. Distribution feeder with LG fault.

If a LG fault occurs on this feeder at some point downstream from the substation, the substation breaker relay will measure this current, and trip if the maximum fault current exceeds the predetermined overcurrent setting. LG faults can be represented as the positive-, negative- and zero-sequence current networks being connected in series, so each sequence network sees the same fault current. Since the substation transformer (which is Δ-Yg) provides the path for zero-sequence current, the fault current will close the loop through this transformer. Note that any feeder transformers that are connected to the primary through either Δ or Y (floating) have equivalent zero-sequence circuit in form of an open circuit, so the fault current will not flow there. Feeder transformers that are Yg-Yg have zero-sequence equivalent circuit as impedance between the
primary and secondary. Fault current, as seen by the substation relay is shown on Figure 17 below and at a particular point on the feeder, the ground fault is 1,633A.

![Figure 17. Feeder fault as seen from the substation – zero sequence](image)

Now, assume that DER is installed at the end of the feeder using Yg – Δ transformer configuration and LG fault occurs at the same location as shown on Figure 18.

![Figure 18. Distribution feeder with LG fault and DER.](image)

Because Yg – Δ transformer provides the zero-sequence path for the ground fault current (see equivalent zero-sequence circuit on Figure 14.), in this case, part of the fault current flows through the Yg – Δ DER transformer \( Z_{TO} \) is the equivalent zero-sequence impedance) and part of the fault current flows back to the substation transformer. In this case, relay associated with the breaker on this feeder sees only portion of the ground fault current and depending on the size of DER and fault current level, the relay might not trip for this fault condition. Figure 19 below shows the current ratio between substation transformer and Yg – Δ DER transformer.
Following, LG fault was simulated the same way as before using different DER ratings, and response was recorded at the substation, fault location and DER site. Figure 20 shows the effect of Yg-Δ transformer configuration on fault currents on the feeder as a function of the size of DER.

As can be seen from the graph, the value of the fault current as seen by the substation feeder relay reduces as the size of the DER increases, when the transformer that DER is connected is Yg-Δ. So, as a cumulative effect, the relay ground settings are de-synthesized, and depending on the size of the DER and fault location, the substation breaker might not trip for LG fault. Figure 21 below shows the current in the neutral of the Yg-Δ DER transformer as a function of increasing DER size. As seen from the graph, zero-sequence fault current at fault location and DER location increases with DER size increase, since this transformer becomes the path for the zero-sequence fault current to flow. Further simulations were carried out and DER sized at 1.8MVA with Yg–Δ DER transformer would prevent the substation relay from tripping on a LG fault.
So, how does this problem get fixed? There are two engineering requirements that must be satisfied in this case in order to solve this problem. First, DER transformer must have zero-sequence equivalent circuit as an open circuit. Second, DER inverter must be connected line-to-line, but neutral of the transformer must not be grounded. Using Yg-Y transformer in place of Yg-Δ transformer at the DER site solves this issue, because Yg-Y transformer configuration does not provide zero-sequence fault current source. Figure 22 shows LG fault simulation with Yg-Y DER transformer and fault current remains the same (1633A).

This chapter provided the analysis that shows the reason why Yg-Δ DER transformer should never be used as preferred configuration when connecting DERs to the effectively grounded distribution feeders. As stated before, review of the IEEE literature showed vast majority of the papers with proposed microgrids being designed with this transformer configuration. This chapter provided one of the shortcomings of such design – decreased reliability and security of the feeder protection and control scheme when microgrid operates in grid-connected mode. However, there
is another shortcoming of using Yg-Δ DER transformer, which will further be explored in the next chapter – effective grounding.

The biggest difference between inverter and generators is that synchronous generators are always grounded by making a connection between the neutral and the ground. However, majority of DER inverters today are designed to accept only line-to-line voltage at their AC inputs and are not built to accept the ground (i.e. they are ungrounded). The main reason why most inverters do not have neutral connection solidly grounded is to prevent the short duration imbalances in phase switching times that would result in neutral current flow. Without this neutral current flow, inverters can better manage their harmonic output, and make it possible to comply with industry accepted standards.

In recent years, some DER inverters were designed to be connected to Yg-Yg DER transformer configuration. Unlike synchronous generators that are designed to sustain fault currents, DERs are not built and designed to provide the zero-sequence path for the fault current. For that reason, the following chapter is important, because the design of microgrid effective grounding has major impact on the safety of customers and withstand rating of the high voltage equipment. DER inverter creates two types of noise as a result of IGBT switching pattern (PWM, space vector or similar). These are differential mode noise and common mode noise. Differential mode noise is mitigated by one of the inductors inside the LCL filter which is integral to the DER inverter. Common mode noise requires more attention from the overall microgrid design. In order to prevent the common mode noise to propagate to the feeder, transformer that DER inverter is connected to MUST BE designed with electrostatic shield (which is grounded) between primary and secondary, so that that common mode noise would circulate between this grounded shield and DC ground inside the inverter (this transformer should also be designed with k=3 factor).
CHAPTER 5: Grounding Transformer Design – New method
Today, very little attention and research has been done regarding the design procedure for grounding transformers within microgrids operating in islanded mode. Authors in [16] provided the background on grounding transformers, types, operation but provide no design and protection philosophy when it comes to the transformer design parameters. In [17] authors assessed the grounding transformer connection methods used within electric utility feeders that have distributed generation (DG) connected to it, and outline criteria for additional protection that might be needed. However, the only DG considered is the back-up generator, which on its own does not require grounding transformer. Authors in [18] examined the temporary overvoltage and ground potential rise on the distribution feeders with multi-grounded neutral wire. However, the authors do not provide any insight into the application of grounding transformer on these feeders, and its effect on the two mechanisms. In [19], authors examined the impact of primary grounding on the low voltage network ground fault currents, un-faulted line-to-line voltages and voltage sags. Authors propose the addition of neutral grounding impedance, reactance grounding, resistance grounding, and the addition of grounding bank. However, the authors never considered the addition of DERs to the feeder and its impact on their analysis. Authors in [20] proposed the use of high-resistance grounding for a large industrial customer with two back-up generators. However, the authors did not provide any analysis regarding the use of inverter-based DERs as backup generation, because high resistance grounding would not provide the proper solution in that case. In [21], authors provided the analysis with respect to line-to-ground faults in cases when grounding transformer is connected on the Y-grounded distribution feeder. However, the article does not provide any insight into the design of the grounding transformer. Authors in [22] provided the overview of microgrid protections and grounding and propose the use of grounding transformer operating in grid-connected mode or using the grounding methods that include the impedance. Both approaches
have shortcomings that reduce the security of the protection and control microgrid scheme. In [23], authors examined the microgrid protection and control scheme based on synchronous-based DG units, which is much less complex compared to the system that uses inverter-based DGs. Authors in [24] proposed the use of D-STATCOM in order to mitigate the voltage imbalance, but the proposed microgrid, which consists of inverter-based DERs, does not include grounding transformer. In [25], the authors provided the overview of challenges associated with properly grounding the microgrid, without going into specific analysis of any of the issues.

Implementation of lessons learned in Chapter 4 regarding the preferred choice of Yg-Y transformer connections associated to DERs leads to the next important contribution of this research – design and implementation of grounding transformer inside the microgrid with inverter-based DERs. If microgrid consists of inverter-based DERs, and DER transformer configuration is Yg-Y or Yg-Yg, then upon transition to islanding operating mode, there is no ground source. For that reason, it is necessary to install a grounding transformer within the microgrid. This transformer is connected to the microgrid only in islanded mode, while it is disconnected when the microgrid operates in grid-connected mode. Today, there is no standard that outlines the design procedure for grounding transformer installed within the microgrids with inverter-based DERs. Grounding transformer is implemented within the microgrid in order to:

1. provide a solid ground reference for the microgrid,
2. enable the design of more reliable and secure microgrid protection and control scheme,
3. enable the grid synchronization,
4. prevent ferroresonance from occurring within the microgrid, and
5. reduce the overvoltages that result from ground faults and open phase conditions.
The earliest practice of installing grounding banks was found in [26], which dates back prior to 1943. At the time, there were three factors being considered for the grounding bank design: maximum amount of unbalanced kVA which may be imposed on the bank for a long period of time, maximum phase to ground kVA that might be imposed on the grounding bank in short period of time and maximum rise above the normal phase to ground voltage on un-faulted phases during LG fault. According to this standard, maximum unbalanced load on distribution circuits should have a minimum capacity of not less than 25% of feeder load if a substation has only one feeder, not less than 15% of the total substation load if substation has two or more feeders or not less than 33.3% of on two un-faulted phases above this value. Since then, a lot of advancements were made and most recent standard [10] outlines the design parameters for the grounding transformer: rated thermal current, rated continuous current, voltage, frequency, BIL level, circuit voltage of system, service location (indoor/outdoor), time and impedance. However, this design does not provide the procedure for designing the grounding transformer parameters.

The rest of this chapter will first provide the calculations-based approach associated with grounding transformer design using the existing IEEE standards [10] and [12] and approach proposed in [27]. Following, new simulations-based approach for the grounding transformer design will be proposed along with the results of simulations. The following Figure 23. shows the one-line diagram of generic microgrid. For the purpose of this simulation, we will assume that the microgrid has been connected to the feeder from Figure 18. at the DER location. Microgrid has a 4-way switchgear, where breaker B1 is PCC and is used as islanding switch. Breaker B2 is connected to the grounding transformer and breaker B3 is connected to the 5 miles long feeder which has a diverse load and a PV farm rated at 100kVA. Breaker B4 is connected to the BESS rated at 150kVA.
The following Table 4 shows the design parameters for the grounding transformer as defined by [10]. The table has five columns. The first column shows the grounding transformer design parameters (1, 2, 3, 4, 5 and 8) along with two new added parameters (6 and 7) that are part of the new simulations-based design approach. The rest of the columns show if the grounding transformer design approach addresses each of the design parameters (Yes/No). Last column shows if the new design approach has a different methodology for each of the grounding transformer design parameters or no (Yes/No).

<table>
<thead>
<tr>
<th>Design parameter</th>
<th>IEEE C62.92</th>
<th>IEEE 1547.8</th>
<th>New design</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Construction</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>2. Voltage level</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>3. Impedance (Z₀)</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>4. Steady-state current</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>5. Fault withstand neutral current</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>6. Fault current analysis</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>7. Transient analysis</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>8. kVA rating</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
</tr>
</tbody>
</table>

5.1. Grounding Transformer design using IEEE C62.92 and IEEE C57.32 Standards

This section covers the design of grounding transformer using the current standard that is implemented on a power system with synchronous generators as the main generation sources ([8], [10] and [12]).
5.1.1. Grounding Transformer Construction

There are two types of configurations for grounding transformer: Yg–Δ or “Zig-Zag” transformer. “Zig-Zag” transformer is more efficient than Yg–Δ transformer and its rating is lower by factor of $\sqrt{3}$, which results in lower construction cost (Yg–Δ transformer has line to ground voltage across all windings, while each winding of "Zig-Zag" transformer has less than the line-to-ground voltage by a factor of $\sqrt{3}$). Preferred grounding transformer construction type for the microgrid was chosen to be Yg–Δ.

![Figure 24. Grounding transformer configurations.](image)

5.1.2. Voltage level

Grounding transformer in this case is connected to the 12.47kV primary system, so that represents that primary side of the voltage. Regarding the secondary side, this voltage can be any level. For the purposes of this design, 480V voltage level is chosen. So, the grounding transformer primary and secondary voltages are 12.47kV Yg – 480V Δ.

5.1.3. Impedance ($Z_0$)

Grounding transformer impedance is typically specified based on two standards: [9] and [12]. [9] is applicable only to the industrial and commercial secondary systems and also it does not include CoG so it does not apply to the grounding transformer design on the distribution
primary system. Grounding transformer impedance $Z_0$ will be calculated using the following methodology from [12]. Total kVA rating of the inverter-based DERs within the microgrid is 250kVA (BESS rated at 150kVA and PV system rated at 100kVA), so that value will be used as the base value. Medium voltage feeder that the microgrid is connected to is 12.47kV, so that values will be used at the base voltage value. From here, base impedance ($Z_{BASE}$) and base current ($I_{BASE}$) values are calculated as:

$$Z_{BASE} = \frac{V_{DER}^2}{S_{DER}} = \frac{12.47kV^2}{250kVA} = 622\Omega$$

$$I_{BASE} = \frac{S_{DER}}{\sqrt{3} \cdot V_{DER}} = \frac{250kVA}{\sqrt{3} \cdot 12.47kV} = 11.5748A$$

Assuming the three-phase fault duty of 2.4p.u. for BESS and 1.5p.u. for PV, total fault duty can be calculated as:

$$S_{FAULT \ DUTY} = 2.4p.\ u. \cdot 150kVA + 1.5p.\ u. \cdot 100kVA = 510kVA$$

Positive ($Z_1$) and negative ($Z_2$) sequence impedance can be calculated as a function of the three-phase fault duty:

$$Z_1 = Z_2 = \frac{S_{DER}}{S_{FAULT \ DUTY}} = \frac{250kVA}{510kVA} = 0.49p.\ u.$$

In effectively grounded systems, where grounding is provided by the means of grounding transformer, maximum LG fault current should be 60% or more of the available 3Φ fault currents (per [12]) in order to prevent large transient overvoltages to occur on the feeder (voltages on unfaulted phases should not increase above 120% of their nominal voltage during the fault). Using the limit of ground fault current ($I_{GF}$) to be 75% of three-phase current, this value is then:

$$I_{GF}[A] = \frac{0.75 \cdot S_{FAULT \ DUTY}}{\sqrt{3} \cdot V_{DER}} = \frac{0.75 \cdot 510kVA}{\sqrt{3} \cdot 12.47kV} = 17.71A$$
Ground fault current in per-unit value $I_{GF}[p.u.]$ is calculated as:

$$I_{GF}[p.u.] = \frac{I_{GF}}{I_{BASE}} = \frac{17.71A}{11.5748A} = 1.53\text{ p.u.}$$

Per-unit zero-sequence current $I_0[p.u.]$ and actual zero-sequence current $I_0[A]$ are then calculated as:

$$I_0[p.u.] = \frac{I_{GF}[p.u.]}{3} = \frac{1.53\text{ p.u.}}{3} = 0.51\text{ p.u.}$$

$$I_0[A] = I_{BASE} \times I_0[p.u.] = 11.5748A \times 0.51\text{ p.u.} = 5.90A$$

Total per-unit impedance $Z_{TOTAL}[p.u.]$ of the grounding transformer is calculated as:

$$Z_{TOTAL}[p.u.] = \frac{V[p.u.]}{I_0[p.u.]} = \frac{1.0\text{ p.u.}}{0.51\text{ p.u.}} = 1.96\text{ p.u.}$$

Total impedance of grounding transformer is equal to the sum of individual sequence impedances ($Z_{TOTAL} = Z_1 + Z_2 + Z_0$). From here, zero-sequence impedance $Z_0[p.u.]$ can be calculated as:

$$Z_0[p.u.] = Z_{TOTAL}[p.u.] - Z_1[p.u.] - Z_2[p.u.] = 1.96\text{ p.u.} - 0.49\text{ p.u.} - 0.49\text{ p.u.} = 0.98\text{ p.u.}$$

Converting p.u. value into Ω value, we get that the zero-sequence impedance of the transformer $Z_0[Ω]$ is:

$$Z_0[Ω] = Z_{BASE} \times Z_0[p.u.] = 622Ω \times 0.98\text{ p.u.} = 609.8 \text{ Ω/phase}$$

The example above places no limitations on the maximum acceptable earth fault factor (EFF). EFF is defined as "at a given location of a three-phase system and for a given system configuration, the ratio of the highest RMS phase-to-earth power-frequency voltage on a healthy phase during a fault to earth affecting one or more phases at any point on the system to the RMS value of phase-to-earth power-frequency voltage which would be obtained at the given location in the absence of any such fault” [14]. Based on the results of the analysis as described above, ratio of negative-sequence impedance to positive-sequence impedance can be calculated as follows:
Using Figure A.2 in [5], and assuming the effective grounding, resulting CoG is approximately 0.75 with \( R_0/X_1 = 1 \). From here, EFF is \( 0.75 \times \sqrt{3} = 1.30 \). Based on these results, since CoG is less than 80%, microgrid is effectively grounded. However, there is one additional element that must be considered - transient overvoltage or ToV. [2] recommends that the grounding transformer is designed with ratios of \( X_0/X_1 \) and \( R_0/X_1 \) in a way that the resulting ToV is 120% or less. Using this value as a guideline, which means that the maximum allowable overvoltage is 20% and CoG = 0.70, and Figure A.2 in [5], resulting \( X_0/X_1 \) is approximately 1.85. From here \( X_0 = 1.85 \times 0.49 \text{p.u.} = 0.90 \text{p.u.} \) and \( R_0/X_1 \) is approximately 0.60. Grounding bank impedance (\( Z_0[\Omega] \)) now is:

\[
Z_0[\Omega] = Z_{\text{BASE}} \times Z_0[\text{p.u.}] = 622 \Omega \times 0.90 = 560 \Omega/\text{phase}
\]

Maximum ground fault current is calculated as:

\[
I_{GF}[A] = \frac{3 \times I_{BASE}}{Z_1 + Z_2 + Z_0} = \frac{3 \times 11.5748A}{0.49 + 0.49 + 90} = 18.47A
\]

As a function of the new maximum ground fault value, short-term kVA rating of the grounding transformer would need to be slightly increased compared to the initial value of 18.47A.

**5.1.4. Steady-state current**

Grounding transformers are designed to carry both short-term fault current and a continuous neutral current. The neutral current is function of the unbalanced microgrid phase currents. Because grounding transformer does not serve any load, positive- and negative-sequence fault currents are open circuits. As a result, the only sequence that is present is the zero-sequence current. Standard [10] section 6.4.2.3 specifies that the basis for this rating is given in section 6.4.2.1 in Table 14. This section states that the thermal current rating is based on the
worst-case ground-fault condition. Table 5 below shows the steady-state continuous grounding transformer rating:

<table>
<thead>
<tr>
<th>Rated time</th>
<th>Continuous duty [% of thermal current rating]</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 seconds</td>
<td>3%</td>
</tr>
<tr>
<td>1 minute</td>
<td>7%</td>
</tr>
<tr>
<td>10 minutes</td>
<td>30%</td>
</tr>
<tr>
<td>Extended time</td>
<td>30%</td>
</tr>
</tbody>
</table>

Based on the two values calculated above for the maximum ground fault current $I_{GF}$ of 17.54A and 18.47A, which determines the transformer thermal current rating, continuous duty rating of this transformer can be calculated as shown in Table 6 below. Continuous neutral current ratings, as provided in this table, could be changed as a function of the desired continuous neutral current requirements.

<table>
<thead>
<tr>
<th>Rated time</th>
<th>Continuous duty [% of thermal current rating]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$I_{GF} = 17.54$A</td>
</tr>
<tr>
<td>10 seconds</td>
<td>0.53</td>
</tr>
<tr>
<td>1 minute</td>
<td>1.23</td>
</tr>
<tr>
<td>10 minutes</td>
<td>5.26</td>
</tr>
<tr>
<td>Extended time</td>
<td>5.26</td>
</tr>
</tbody>
</table>

5.1.5. Fault withstand neutral current

Maximum value of fault current through the grounding transformer neutral was calculated above to be 18.47A.

5.1.6. Fault current analysis

Simulations-based fault current analysis is not part of the existing Standard [12]. In this case, the fault current has been determined using the calculations-based approach.

5.1.7. Transient analysis

Simulations-based transient analysis is not part of the existing Standard [12].
5.1.8. kVA rating

Yg-Δ grounding transformer provides only path for zero-sequence current and has no load most of the time, so it’s positive- and negative-sequence networks are open circuits. The short-time kVA rating is calculated then as:

\[ kVA = \frac{V_{LL} * I_N}{\sqrt{3}} = \frac{12.47kV * 18.47A}{\sqrt{3}} = 132.97VA \]

The Zig-Zag transformer has both windings connected to the primary 12.47kVA circuit. For that reason, short time kVA rating is calculated as:

\[ kVA = \frac{V_{LL} * I_N}{3} = \frac{12.47kV * 18.47A}{3} = 76.77MVA \]

Table 7 below shows the final characteristics of grounding transformer using the approach proposed in [12].

<table>
<thead>
<tr>
<th>Design parameter</th>
<th>IEEE C62.92.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Construction</td>
<td>Yg-Δ</td>
</tr>
<tr>
<td>2. Voltage level</td>
<td>12.47kV – 480V</td>
</tr>
<tr>
<td>3. Impedance (Z₀)</td>
<td>560 Ω/phase</td>
</tr>
<tr>
<td>4. Steady-state current</td>
<td>5.54A</td>
</tr>
<tr>
<td>5. Fault withstand neutral current</td>
<td>18.47A</td>
</tr>
<tr>
<td>6. Fault current analysis</td>
<td>-</td>
</tr>
<tr>
<td>7. Transient analysis</td>
<td>-</td>
</tr>
<tr>
<td>8. kVA rating</td>
<td>132.97kVA</td>
</tr>
</tbody>
</table>

5.2. Grounding Transformer design using IEEE 1547.8 Standard (Draft)

This section covers the design of grounding transformer using the Draft/Proposed IEEE 1547.8 Standard. Note that this standard was not accepted, but it contained the procedure for the design of grounding transformer.
5.2.1. Grounding Transformer Construction

There are two types of configurations for grounding transformer: Yg–Δ or “Zig-Zag” transformer. “Zig-Zag” transformer is more efficient than Yg–Δ transformer and its rating is lower by factor of √3, which results in lower construction cost (Yg–Δ transformer has line to ground voltage across all windings, while each winding of “Zig-Zag” transformer has less than the line-to-ground voltage by a factor of √3). Preferred grounding transformer construction type for the microgrid was chosen to be Yg–Δ.

5.2.2. Voltage level

Grounding transformer in this case is connected to the 12.47kV primary system, so that represents that primary side of the voltage. Regarding the secondary side, this voltage can be any level. For the purposes of this design, 480V voltage level is chosen. So, the grounding transformer primary and secondary voltages are 12.47kV Yg – 480V Δ.

5.2.3. Impedance (Z₀)

Transformer impedance is typically specified based on two standards: IEEE – 142 and IEEE 1547.8. The first standard (IEEE – 142) recommends the grounding transformer impedances R₀ and X₀ and ratios of R₀/X₁ and X₀/X₁ to be designed so that the temporary overvoltage (ToV) is 120% or less without the utility being connected. The recommended values for the ratios are R₀/X₁ ≤ 1 and X₀/X₁ ≤ 3. The biggest challenge with this approach is the fact that it is difficult to define the DER inverter’s positive and negative sequence impedances.

The second standard (IEEE 1547.8) uses different approach. First, impedance base in calculated as:

\[ Z_{BASE} = \frac{V_{DER}^2}{S_{DER}} \]
Grounding transformer reactance and resistance are then found using the following relationships:

\[ X_g = 0.6 \times Z_{BASE} \]

\[ \frac{X_g}{R_g} \geq 4 \]

The value for \( X_g \) of 60% of the base impedance is based on the very conservative approximation that the steady-state fault current contribution of the DER is 167% of the nominal current (as known, the typical range of the fault currents supplied by the inverter-based DERs is less than 2.0 p.u. range). So, in the proposed microgrid case, total inverter based DER capacity is \( S = 250kVA \), and for the base primary voltage of 12.47kV, the base impedance is:

\[ Z_{BASE} = \frac{V_{DER}^2}{S_{DER}} = \frac{(12.47kV)^2}{250kVA} = 622 \, \Omega \]

\[ X_g = 0.6 \times Z_{BASE} = 0.6 \times 622 \, \Omega = 373.2 \, \Omega \]

\[ \frac{X_g}{R_g} \geq 4 \implies R_g \leq \frac{X_g}{4} \text{ or } R_g \leq \frac{373.2 \, \Omega}{4} \text{ or } R_g \leq 93.3 \, \Omega \]

Note that building transformers with the exact values as calculated above is challenging, so ±10% impedance toleration is allowed.

5.2.4. Steady-state current

Unbalanced distribution phase voltages result in a zero-sequence component, which results in the steady state circulating currents. Short-circuit analysis models the current source DERs as completely positive sequence, so for negative and zero sequence, DER current sources are open circuits. For that reason, during the fault, DER zero-sequence impedance is equivalent to the grounding transformer impedance. Since grounding transformer does not serve any load, positive and negative sequence are open circuits, so the only sequence that is present is the zero-sequence, which means that only zero-sequence current flow through the grounding transformer during the
fault conditions. Since impedance of the transformer has been calculated in 5.2.3. the circulating current $I_g'$ can be calculated based on the zero-sequence voltage across the grounding bank as a function of the phase-to-phase imbalance, using Ohm’s Law.

Symmetrical components of any set of phase voltages can be expressed as:

$$\begin{bmatrix} V_{A0} \\ V_{B0} \\ V_{C0} \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \ast \begin{bmatrix} V_A \\ V_B \\ V_C \end{bmatrix}$$

where,

$V_A = 1\angle 0^\circ p. u.$

$V_B = ax \ast V_A$

$V_C = a^2y \ast V_A$

$a = 120^\circ$ phase shift operator

Combining these equations, zero-sequence voltage expression becomes:

$$V_{A0} = \frac{V_A}{3} \ast (1 + ax + a^2y)$$

or

$$V_{A0} = \frac{V_{A1}}{3} \ast (1 + x(cos\theta_b + jsin\theta_b) + y(cos\theta_c + jsin\theta_c))$$

$V_{A0}$ can also be rewritten for a case when the phases are exactly 120 degrees apart in a different form by using the complex numbers (in real field situations, this is not the case, because the system is never perfectly balanced, and also the incoming lines to the substation are never perfectly transposed, but the approximation is in the range of actual numbers):

$$V_{A0} = \frac{V_{A1}}{3} \ast (1 + x(-\frac{1}{2} + j\frac{\sqrt{3}}{2}) + y(-\frac{1}{2} - j\frac{\sqrt{3}}{2}))$$

Additional simplification can be made that phase to phase voltage imbalance is always symmetrical, which means that if the field imbalance is 3%, then phase B is 1.5% above the phase
A, and phase C is 1.5% below phase A. Defining the percent imbalance between the phases $P$, the following equations hold:

$$x = 1 + \frac{P}{2}$$

$$y = 1 - \frac{P}{2}$$

Substituting these values in the equation for $V_{a0}$, we get:

$$V_{A0} = j \sqrt{3} \frac{6}{6} \cdot P \cdot V_{A1}$$

Using Ohm’s Law, the circulating current can be found as:

$$I_g' = \frac{\sqrt{3} P \cdot V_{A1}}{6Z_g}$$

Using this formula, it is possible to approximate the continuous current, but this approach results in the lower value of the constant current through the grounding transformer. In real power system, voltage imbalance is almost never symmetrical and in addition voltages are never exactly 120 degrees apart. In order to see how much the value for $I_g'$ is lower than measured in the field, we will assume that the phase voltage imbalances can vary from -5% to 5% (according to ANSI C84.1 standard, the voltage at the customer point should be in $V_{NOM} \pm 5\%$ range) and plot the value of $V_{A0}$ vs. $V_{A0}$ for the symmetrical imbalance of 5%. Figure 25 below shows the results of this analysis. As can be seen from this graph, same value of symmetrical and asymmetrical phase imbalance can result in higher $V_{a0}$ for the asymmetrical case. From the graph, if we assume the symmetrical phase imbalance of 3% ($x = 0.985$ and $y = 1.015$) and asymmetrical phase imbalance of 3% ($x = 1.00$ and $y = 1.03$), $V_{a0}$ for the asymmetrical case is larger by 15.47%. As voltages can vary $\pm 5\%$ for the highly unlikely case when one phase is at its minimum of $x=0.95$ and the other
phase is at its maximum of $y = 1.05$, the highest ratio obtained is 2 (note that this is highly unlikely in real field scenario due to the numerous reasons).

Figure 25. $V_{A0}$ vs. $V_{A0}$ for symmetrical 5% imbalance case as a function of $x$ and $y$.

Similarly, the analysis for the voltage phase angles shows that 5% voltage imbalance does not cause the change in $\theta_b$ and $\theta_c$ of more than 3 degrees. However, in extreme cases for $\theta_b$ and $\theta_c$ being at their maximum limits of ±5 degrees, the magnitude of $V_{A0}$ is 3.72. In real system operation, this is not possible, because phase changes are typically small and subtle, so this factor could be taken from the analysis.

Figure 26. $V_{A0}$ vs. $V_{A0}$ for symmetrical 5% imbalance case as a function of the voltage angle.
Given that the values for \( x \), \( y \), \( \theta_b \) and \( \theta_c \) are typically not known during the planning stage, and using the analysis from the two figures above, the proposed procedure to calculate the circulating current is to double the maximum value for \( V_{A1} \) (Figure 25 shows that the maximum increase of \( V_{A1} \) is by factor 2.0, while Figure 26 shows this factor to be 3.72, but the second factor can be neglected):

\[
I_g' = \frac{\sqrt{3}P \times 2V_{A1}}{6Z_g} = \frac{P \times V_{a1}}{\sqrt{3}Z_g}
\]

Considering the primary voltage of 12.47kV, the size of the DER inside the microgrid of 250kVA, \( \pm 10\% \) of the transformer impedance tolerance, and expected voltage imbalance between \([0 – 5]\) \%, circulating ground current is given in the following Table 8. From the current above, the maximum steady-state unbalance current is 0.60A for the maximum expected voltage imbalance of 5%.

| Table 8. Expected voltage imbalance effect on the circulating grounding current |
|---------------------------------|-----------|-----------|
| DER Size | 250 kVA |
| Primary Voltage \( V_{LL} \) | 12.47 kV |
| \( Z_{BASE} \) | 622 \( \Omega \) |
| \( R_G \) | 93.3 \( \Omega \) |
| \( X_G \) | 373.2 \( \Omega \) |
| Expected Imbalance | \( I_g \) (\( Z_G \) MIN) [A] | \( I_g \) (\( Z_G \) MAX) [A] |
| 1.00\% | 0.12 | 0.10 |
| 2.00\% | 0.24 | 0.20 |
| 3.00\% | 0.36 | 0.30 |
| 4.00\% | 0.48 | 0.40 |
| 5.00\% | 0.60 | 0.50 |

5.2.5. Fault withstand neutral current

Calculating the withstand capability of the grounding transformer is also based on Ohm’s
Law. The main challenge is to determine the zero-sequence voltage $V_{a0}$ during the fault. If the grounding impedance is of the order of $1\Omega$, the maximum value of $V_{a0}$ is 90% of the positive sequence voltage. Note that for the solid grounding the impedance should be less than $1\Omega$. The worst-case value of the ground fault current on 12.47kV side as seen in the neutral of the grounding transformer is:

$$I_g = \frac{V_{a1}}{Z_g} = \frac{12.47kV}{(93.3 + j373.2 )\Omega} = 32.42 \, A$$

5.2.6. Fault current analysis

This section is the same as Section 5.1.6.

5.2.7. Transient analysis

This section is the same as Section 5.1.7.

5.2.8. kVA rating

This is the part of analysis that is different compared to the section 5.1.8. One of the requirements for the design of grounding transformer using this approach is that the grounding transformer must be able to withstand the fault current and also from Section 5.2.3. the X/R ratio of this transformer has to be greater than or equal to 4. Using traditional approach, the kVA rating of the Yg-$\Delta$ grounding transformer can be calculated as:

$$kVA = \frac{V_{LL} \ast I_N}{\sqrt{3}} = \frac{12.47kV \ast 32.42A}{\sqrt{3}} = 233.42kVA$$

This is the minimum short-term kVA rating of the grounding transformer. With respect to the second requirement ($X/R \geq 4$), the research of the available three-phase transformers, traditionally used by the electric utilities and their respective X/R ratios was conducted. Traditional ratings were taken to be 75kVA, 150kVA, 225kVA, 300kVA and 500kVA. Three-phase transformers rated at 300kVA have ratios greater than 3, but less than 4, while three-phase
transformers rated at 500kVA have X/R ratios in excess of 5. So, as a result, the short-term kVA rating of grounding transformer is taken to be 500kVA.

Table 7 below shows the final characteristics of grounding transformer using the approach proposed in [27].

<table>
<thead>
<tr>
<th>Design parameter</th>
<th>IEEE 1547.8</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Construction</td>
<td>Yg-Δ</td>
</tr>
<tr>
<td>2. Voltage level</td>
<td>12.47kV – 480V</td>
</tr>
<tr>
<td>3. Impedance (Z₀)</td>
<td>R₀=93.3 Ω/phase, X₀=373.2 Ω/phase</td>
</tr>
<tr>
<td>4. Steady-state current</td>
<td>0.6A</td>
</tr>
<tr>
<td>5. Fault withstand neutral current</td>
<td>32.42A</td>
</tr>
<tr>
<td>6. Fault current analysis</td>
<td>-</td>
</tr>
<tr>
<td>7. Transient analysis</td>
<td>-</td>
</tr>
<tr>
<td>8. kVA rating</td>
<td>500kVA</td>
</tr>
</tbody>
</table>

The main question that one might ask is as follows: is it possible to energize the grounding transformer rated at 500kVA with BESS rated at 150kVA and PV rated at 100kVA and not cause microgrid blackout? Grounding transformer inrush current during the energization causes voltage sags and flicker, and if the BESS does not have enough reactive power capacity, the microgrid can fail on the undervoltage condition. It is possible to energize the grounding transformer in excess of the BESS rating, but grounding transformer inrush current mitigation technique must be implemented within the microgrid. The author of this paper has designed, implemented and tested three different mitigation schemes for the grounding transformer inrush current, all which were successful, but this is not the topic of this research paper.

5.3. Grounding Transformer design – New approach

This section covers the new approach to the grounding transformer design. Unlike the existing standards for the design of grounding transformer that are calculations-based, the new proposed approach in this paper is mostly simulations-based. New approach for the grounding transformer design specifications is based on the fact that the available fault currents from
inverter-based DERs are significantly lower than the fault currents from synchronous generators, and in order to properly design the grounding transformer, using existing standards results in the following two unwanted scenarios:

1. Improper grounding transformer continuous and fault current rating that can cause the grounding transformer to fail, and
2. Improper zero-sequence impedance that can result in voltages on un-faulted phases to reach levels highly above both ToV and CoG ratings, which can cause the damage on feeder medium voltage devices and customer loads.

5.3.1. Grounding Transformer Construction

Compared to the standards-based approach, there is no change in this section, as there are only two choices for grounding transformer as outlined before. Preferred grounding transformer construction type for the microgrid was chosen to be $Yg-\Delta$.

5.3.2. Voltage level

Similar to above, compared to the standards-based approach, there is no change in this section. Grounding transformer primary voltage is 12.47kV, while secondary voltage is 480V.

5.3.3. Impedance ($Z_0$)

In order to find the impedance of the grounding transformer, iterative process was implemented, where grounding transformer design was chosen based on the continuous nameplate rating of four different transformers typically used on the distribution level, ranging from 75kVA to 500kVA (note that the values chosen are typical electric utility standards-based kVA ratings for three-phase transformers). Grounding transformer design parameters are shown in Table 10 below. Note that the per unit values were calculated as a function of the transformer nameplate rating.
Table 10. Grounding transformer impedance values

<table>
<thead>
<tr>
<th>kVA</th>
<th>R[p.u.]</th>
<th>X[p.u.]</th>
<th>Z[p.u.]</th>
<th>X/R ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>75</td>
<td>0.010</td>
<td>0.025</td>
<td>0.027</td>
<td>2.5</td>
</tr>
<tr>
<td>150</td>
<td>0.020</td>
<td>0.064</td>
<td>0.067</td>
<td>3.2</td>
</tr>
<tr>
<td>300</td>
<td>0.014</td>
<td>0.073</td>
<td>0.074</td>
<td>4.70</td>
</tr>
<tr>
<td>500</td>
<td>0.020</td>
<td>0.114</td>
<td>0.116</td>
<td>5.70</td>
</tr>
</tbody>
</table>

In addition, grounding transformer does not serve any load (its secondary is open circuit), and for that reason, both positive- and negative-sequence current networks are open circuits. Consequently, only zero sequence currents can flow in the grounding transformer. With these four choices for grounding transformer, both fault current analysis and transient analysis were done as outlined in 5.3.6. and 5.3.7. Impedance value is calculated in section 5.3.6.1. as it requires the fault current simulations-based analysis for determining the value. Based on the analysis, $Z_0 = 0\Omega$ provides the best solution for microgrid design.

5.3.4. Steady-state current

In order to provide the motivation for the new approach, steady-state circulating current $I_N$ was measured within the actual electric utility’s microgrid under different voltage and load imbalances and was recorded for approximately 30 different field operating conditions. Figure 27 below shows the results of field measurements.

Figure 27. Microgrid steady-state circulating current $I_N$. 
As seen from the graph, voltage unbalance on phases A, B and C respectively of [1.025 - 1.04]p.u., [1.025 - 1.035]p.u. and [1.015 - 1.04]p.u. result in the neutral current $I_N$ range from [0.7-2.6]A. Comparing this range to the values from Table 6. Grounding transformer steady-state current rating, we can see that the maximum value of $I_N$, as recorded, of 2.6A significantly exceeds both 10-second and 1-minute ratings of grounding transformer, but it is well within the 10-minute and extended ratings. Similarly, the maximum value of $I_N$, as recorded, of 2.6A significantly exceeds the maximum value for steady state current of 0.6A from Table 8. Since Table 6. Grounding transformer steady-state current rating represents IEEE standards-based grounding transformer ratings, the first proposed change is to include only two, rather than four ratings, for the microgrid grounding transformer (which is effectively Table 14 in [10] section 6.4.2.1). These ratings would be designated as continuous duty rating, and short circuit current rating. Regarding the continuous duty rating, it should only have extended time rating, while 10 seconds, 1 minute and 10-minute ratings are not necessary. This rating should be simulations-based as shown in this section, and not related to the percentage of the thermal continuous rating.

<table>
<thead>
<tr>
<th>Rated time</th>
<th>Continuous duty</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 seconds</td>
<td>-</td>
</tr>
<tr>
<td>1-minute</td>
<td>-</td>
</tr>
<tr>
<td>10 minutes</td>
<td>-</td>
</tr>
<tr>
<td>Extended time</td>
<td>Simulations-based – $3*I_{N\text{MAX}}$</td>
</tr>
</tbody>
</table>

The new approach for calculating the neutral current during the maximum microgrid phase imbalance conditions is based on the author’s proposal of using the maximum load imbalance of ±35%. How was this value obtained? The most sensitive loads on any feeder are motors, because any voltage unbalance on the feeder can negatively impact the operation of these devices. Motors are typically classified based on the power source type, internal construction, application and type of motion output. Motor protection and control schemes are design to protect against thermal
overload, phase fault, ground fault and abnormal operating conditions, couple of which is voltage and current unbalance. Unbalanced substation voltages, blown fuses and single-phasing are typical causes of the feeder current unbalance. This unbalance is reflected in negative sequence voltage and current that results in the motor stress and rotor overheating. For a typical 3-phase induction motor, 1% of voltage imbalance results in 7% of current imbalance. Standard [28] recommends that “electric supply systems should be designed and operated to limit the maximum voltage unbalance to 3 percent when measured at the electric-utility revenue meter under no-load conditions.” Section 14.36 in [29], which represents manufacturers of motors and drives, states that ”operation of the motor above a 5% voltage unbalance condition is not recommended” and provides also a de-rating curve for operation under voltage unbalance. Section 14.36.5 of the same standard states that a motor operating at normal speed under the voltage unbalance conditions causes current unbalance in the order of 6-10 times. Taking more stringent requirement of 5% for total feeder voltage unbalance, and if each 1% of voltage unbalance causes 7% of current unbalance, maximum load imbalance is calculated to be ±35%. This value was then taken for calculations of grounding transformer maximum steady-state neutral current.

Using the load unbalance values of ±35% simulations for four different use cases were carried out, and results of the study are shown below in Table 12 with steady-state circulating current designated as \( I_N \). Figure 28 shows the unbalance current within the microgrid during grid-connected and islanded mode. The unbalanced current flows through the grounding transformer. As can be seen from the simulation, the maximum steady-state circulating current from Table 12. Microgrid normal operation with 35% load imbalanceis 2.72A. This value is slightly higher than 2.6A value obtained from the field measurements. Simulated value is also larger than both 10second and 1-minute steady-state current rating.
Given that the steady-state value can last indefinitely (in theory), 10-second and 1-minute ratings as described in Table 6. Grounding transformer steady-state current rating are not practical for determining the continuous duty microgrid transformer ratings.

Table 12. Microgrid normal operation with 35% load imbalance

<table>
<thead>
<tr>
<th>Case</th>
<th>Load</th>
<th>PV</th>
<th>BESS</th>
<th>$I_N$ [A]</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.0 p.u.</td>
<td>1.0 p.u.</td>
<td>VSI-ISO</td>
<td>2.72</td>
</tr>
<tr>
<td>2</td>
<td>1.0 p.u.</td>
<td>OFF</td>
<td>VSI-ISO</td>
<td>2.72</td>
</tr>
<tr>
<td>3</td>
<td>0.3 p.u.</td>
<td>0.2 p.u.</td>
<td>VSI-ISO</td>
<td>0.84</td>
</tr>
<tr>
<td>4</td>
<td>0.3 p.u.</td>
<td>OFF</td>
<td>VSI-ISO</td>
<td>0.84</td>
</tr>
</tbody>
</table>

Feeder loading and operating conditions constantly change, so the value for the neutral current steady-state rating must change. Neutral current steady-state ratings provided in sections 5.1.4. and 5.2.4. assume only current microgrid state, and provide no margin for any microgrid load changes or any potential future load increases, etc…For that reason, the new proposed approach involves using the simulations-based maximum steady-state grounding transformer neutral current $I_N$ of 2.72A and multiplying it by some margin.
In this case, safe margin was chosen to be three times the maximum neutral current $I_N$ or:

$$I_{\text{Continuous duty}} = 3 \times I_{\text{NMAX}} = 3 \times 2.72A = 8.16A$$

Using this value and the kVA rating formula for the grounding transformer, we get the following continuous duty rating for the microgrid grounding transformer:

$$kVA = \frac{V_{LL} \times I_{N}}{\sqrt{3}} = \frac{12.47kV \times 8.16A}{\sqrt{3}} = 58.75kVA$$

Now, Table 13 shows the grounding transformer continuous rating as a function of only extended time:

<table>
<thead>
<tr>
<th>Rated time</th>
<th>Continuous duty</th>
</tr>
</thead>
<tbody>
<tr>
<td>Extended time</td>
<td>8.16A or 58.75kVA</td>
</tr>
</tbody>
</table>

### 5.3.5. Fault withstand neutral current

In order to determine the fault withstand neutral current rating, it is necessary to perform the fault current analysis, as defined in 5.3.6. below. The results are displayed in Table 14, and the maximum fault withstand current based on the simulations was found to be 31.28A.

### 5.3.6. Fault current analysis

In order to determine the value of zero-sequence impedance $Z_0$ as well as the fault withstand neutral current rating, the authors propose the new simulations-based section called fault current analysis. The analysis consists of the following sub-sections:

1. LG, LL, LLG, and 3Φ fault analysis,
2. Calculation of CoG,
3. Open-phase fault conditions, and
5.3.6.1. LG, LL, LLG, and 3Φ fault analysis

Short-circuit analysis was done for four different faults (LG, LL, LLG and 3Φ) on both medium-voltage feeder primary, as well as the feeder secondary. First, the analysis was done at the location where both DERs and grounding transformer are located. This analysis provides the data for microgrid relay protection settings. The analysis was also done by placing the faults at the furthest point on the feeder, because in this case, feeder impedance has a major impact on the fault current levels. In addition, fault analysis was done on the secondaries of 12.47kV - 277V/480V transformers and well as 12.47kV - 120V/240V transformers, because low fault currents result in protective devices (such as fuses, reclosers or breakers) not being able to clear the fault. Grounding transformer size has a major impact on the level of fault currents within the microgrid. Higher grounding transformer rating results in higher fault currents. However, there is a caveat. First, higher grounding transformer rating would require the higher inverter-based DER rating (this would be the DER that provides the voltage regulation within the microgrid) in order to be able to energize the grounding transformer without faulting the system. Second, at some point, percentage increase in grounding transformer rating has little or no effect on the ground fault current. For that reason, there is an optimum solution regarding the grounding transformer rating, that provides effective CoG, enough ground fault current but it does not result in the microgrid black-out or power quality events when energized by inverter-based DERs. Figure 29 below shows the fault current level as a function of grounding transformer kVA rating.

Part of the fault current analysis is to determine the transformer kVA rating and impedance that will result in effective grounding (CoG<0.8), enough fault current for relays to have secure and reliable protection and control scheme and not cause the microgrid black-out and power quality events when energized.
Figure 29. LLG fault current as a function of grounding transformer kVA rating.

For each of the four use cases in Table 12, phase voltages, voltage sequence networks, phase currents, current sequence networks as well as grounding transformer neutral current was recorded for all four different faults (LG, LL, LLG and 3Φ). The only results presented in this paper are the ones relevant for the analysis. Results displayed in Table 14 below show that the maximum circulating current $I_N$ measured during any of the fault cases is 31.28A during LLG fault, and that the maximum 3Φ fault is 44.09A as shown in Table 15.

<table>
<thead>
<tr>
<th>Case</th>
<th>Fault current [A]</th>
<th>Neutral current [A]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Min</td>
<td>Max</td>
</tr>
<tr>
<td>LG fault</td>
<td>13.56</td>
<td>16.25</td>
</tr>
<tr>
<td>LLG fault</td>
<td>18.57</td>
<td>36.37</td>
</tr>
</tbody>
</table>

Table 15. Circulating current $I_N$ during 3Φ faults

<table>
<thead>
<tr>
<th>Case</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
</tr>
</thead>
<tbody>
<tr>
<td>3Φ fault</td>
<td>44.09</td>
<td>28.41</td>
<td>31.19</td>
<td>40.09</td>
</tr>
</tbody>
</table>

Note that these values as shown in the figure represent the peak transient RMS value. As expected, LL and 3Φ faults do not result in grounding transformer neutral current change, so the results used for the grounding are based on the analysis for both LG and LLG faults. Three-phase fault duty can be now calculated as:

$$S_{3\Phi}[kVA] = \sqrt{3} \cdot I_{3\Phi} \cdot V_{LL} = \sqrt{3} \cdot 44.09 \cdot 12.47 kV = 952.26 kVA$$
Assume that at this point, we want to use the method outlined in [12] for determining the value of $Z_0$. Positive-sequence impedance ($Z_1$) and negative-sequence impedance ($Z_2$) can be now calculated as:

$$Z_1[p. u.] = Z_2[p. u.] = \frac{S_{DER}}{S_{FAULT DUTY}} = \frac{250kVA}{952.26kVA} = 0.262p. u.$$ 

Ground fault current is then calculated based on the largest simulation-based value for the LG and LLG current faults, as outlined in Table 14.

$$I_{GF}[p. u.] = \frac{\text{max}(I_{GF})}{I_{BASE}} = \frac{31.28A}{11.5748A} = 2.70p. u.$$ 

Zero-sequence current is calculated as simply 1/3 of the ground fault current:

$$I_0[p. u.] = \frac{I_{GF}[p. u.]}{3} = \frac{2.70p. u.}{3} = 0.90p. u.$$ 

Grounding transformer total impedance is then calculated as:

$$Z_{TOTAL}[p. u.] = \frac{V[p. u.]}{I_0[p. u.]} = \frac{1.0p. u.}{0.90p. u.} = 1.11p. u.$$ 

From here, using 250kVA as the base value, zero-sequence impedance is calculated as:

$$Z_0[p. u.] = Z_{TOTAL}[p. u.] - Z_1[p. u.] - Z_2[p. u.] = 1.11 - 0.262 - 0.262 = 0.586p. u.$$ 

Converting this value into value, we get that the zero-sequence impedance of the transformer ($Z_0[\Omega]$) is:

$$Z_0[\Omega] = Z_{BASE} \times Z_0[p. u.] = 622\Omega \times 0.586 = 364.5\Omega/\text{phase}$$

Since it is very challenging to design the grounding transformer with the exact impedance as specified above, some tolerance is typically allowed. For that reason, the final zero-sequence impedance of grounding transformer ($Z_0[\Omega]$) can be specified as:

$$Z_0[\Omega] = 364.5\Omega/\text{phase} \pm 10\%$$
This $Z_0$ value, obtained using the calculations-based approach as outlined in the current standard [12] is misleading because inserting the zero-sequence impedance between the neutral and ground of the grounding transformer causes two unwanted consequences. Voltage at the fault location depends on the characteristics of the microgrid and fault impedance. Most inverter-based DERs produce positive- and negative-sequence currents, while grounding transformer provides the path for system unbalance currents and zero-sequence currents during the ground faults. Since microgrid has several relays, voltage measured by the relay is a function of the voltage at the fault location and voltage drop between the fault location and relay location. DER fault current contribution is the function of its maximum fault current capability and the sum of the impedance to the fault location and fault impedance itself. During the ground fault, $Z_0$ impedance inserted between the neutral and ground of the grounding transformer causes the voltage on un-faulted phases to increase, because of the voltage drop across the $Z_0$ caused by the fault current flow (note that during LL and 3Φ faults, there is no fault current flowing through $Z_0$). Figure 30 below shows the voltage on un-faulted phase B rising as a function of the $Z_0$ impedance levels (the other un-faulted phase (phase C) shows similar behavior). As seen from the graph, the lowest value for the un-faulted voltage is when $Z_0 = 0\Omega$.

![Figure 30. Un-faulted voltage $V_B$ as a function of $Z_0$.](image)
Second unwanted consequence of inserting \(Z_0\) impedance is the reduction of the available fault current, because of the additional impedance \((Z_0)\) that is in the path of the fault current. Since fault currents are low to begin with, this even further complicates the design of the reliable and secure protection and control scheme. Figure 31 below shows the fault current decrease as a function of the increasing \(Z_0\) impedance.

![Fault current graph](image)

**Figure 31.** LG fault current as a function of \(Z_0\).

Like before, the highest value for the fault current is when \(Z_0 = 0\Omega\). The main conclusion here is that the design of zero-sequence impedance \(Z_0\) must be iterative process, starting with \(Z_0 = 0\Omega\). Based on the analysis, \(Z_0 = 0\Omega\) provides the best solution for microgrid design, so that value will be used moving forward.

Next, LG fault was also simulated with different fault resistance (baseline resistance was taken to be 200m\(\Omega\)), and as expected, with increasing fault resistance, the fault current value reduces, and for the faults with resistance over 1000\(\Omega\), the 50N1P set-point cannot reliably be used as a protective element. For that reason, new protection scheme was designed that uses voltage sequence elements to torque-control the 50N1P setting. Figure 32 below shows that analysis for 500kVA grounding transformer (the same analysis was done for 75kVA, 150kVA and 300kVA grounding transformers with similar response).
Figure 32. LG fault response with changing fault resistance.

Following, LG and 3Φ faults were placed at the end of the feeder, and as expected, lower fault current values were recorded because of the added impedance. Like before, using 4 different grounding transformer sizes, simulations showed that the ratio of LG to 3Φ faults is greater than 60%, which is the requirement for effectively grounded system. Table 16 shows the results for single-phase and three-phase fault analysis.

<table>
<thead>
<tr>
<th>kVA</th>
<th>I_{LG} [A]</th>
<th>I_{3Φ} [A]</th>
<th>I_{LG} &gt; 60% * I_{3Φ}</th>
<th>Candidate</th>
</tr>
</thead>
<tbody>
<tr>
<td>75</td>
<td>7.74</td>
<td>10.84</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>150</td>
<td>7.75</td>
<td>10.91</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>300</td>
<td>7.75</td>
<td>11.02</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>500</td>
<td>7.82</td>
<td>11.06</td>
<td>Yes</td>
<td>Yes</td>
</tr>
</tbody>
</table>

5.3.6.2. Calculation of CoG

Coefficient of Grounding or CoG is defined in [10] as “the ratio E_{LG}/E_{LL} (expressed as a percentage), of the higher RMS line-to-ground power-frequency voltage E_{LG} on a sound phase, at a selected location, during a fault to ground, affecting one of more phases to the line-to-line power-frequency voltage E_{LL} that would be obtained at the selected location with the fault removed.” Effectively grounded system is then defined as the system that is grounded through a sufficiently
low impedance, so that the resulting CoG does not exceed 80%. What this essentially means is that if the system experiences LG fault on phase A, voltages on un-faulted phases should not exceed 138% of their line-to-line rating prior to the fault. Typically, in order to achieve the desired CoG limit, grounding transformer would need to be designed, per [10], such that $0 < X_0/X_1 \leq 3$, and $0 < R_0/X_1 \leq 1$. LG fault simulation was done within the microgrid using 4 transformers using the same X/R ratio and changing the R and X parameters (therefore changing the impedance) in order to achieve the desired X/R ratio as seen on the Figure 33. Based on the simulation, there two conclusions:

1. grounding transformer with higher ratings provide the desired CoG of less than 80% for all impedance ranges, and
2. it is possible to achieve the desired effective grounding with smaller grounding transformer size (in this case, both 75kVA and 150kVA) if the transformer impedance is lower than 3.5% in this case.

![Figure 33. CoG as a function of Grounding Transformer Impedance.](image-url)
Zooming the graph on Figure 33 in the area of low transformer impedance, we get the graph as shown on the following Figure 34:

![Graph](image)

Figure 34. CoG for the actual 75kVA, 150kVA, 300kVA and 500kVA grounding transformers.

However, using lower value (such as 75kVA) for the grounding transformer short-term (10-seconds) rating is misleading, because this transformer also needs to be able to carry the fault current. For that reason, additional fault current analysis must be carried out.

### 5.3.6.3. Open phase fault conditions

Open phase condition can happen anywhere within the microgrid, and for the purposes of simulation, three cases will be examined, where open phase happens at the location that includes:

1. BESS only,
2. BESS and grounding transformer without load, and
3. BESS and grounding transformer with load.

If open phase happens within the area of microgrid that includes BESS only (for example, one phase of medium-voltage breaker fails to close during the microgrid energization), then the inverter protection will cause the microgrid to trip as seen on the Figure 35 below.
As seen from the graph, voltage on BESS side increases significantly (reaching 4p.u. on the open phase) above the overvoltage setting (59P2P) of 1.2p.u. with 5 cycle time delay. This would cause the BESS to trip. As voltage on phase A collapses on the microgrid side due to the open phase, it reaches the second undervoltage level (27P2P) of 0.5p.u with time delay of 10 cycles, which will result in relays associated with 4-way switchgear to trip. This is seen by the voltage collapse on 12.47kV side. Note that the grounding transformer size has no impact on this condition.

If open phase happens within the area of microgrid that includes both BESS and grounding transformer without any load, then the voltage within the microgrid upstream from the open phase is as shown on Figure 36 below. As seen from the graph, regardless of the size of grounding transformer, the CoG coefficient is still less than 80%. Under certain conditions, a ferroresonance might occur. This analysis is presented in Transient analysis section 5.3.7. and design of grounding transformer must include the results of this section. In order to reduce the amount of overvoltage, some microgrid designs include the installation of series resistance along with the grounding transformer. If open phase happens in the area with load, then the response is similar to the one on Figure 36. In practical application, it is not possible to have the area without load, because at a
minimum BESS has auxiliary load, which is in order of several tens of kilowatts (HVAC being the largest load).

![Graph showing voltage over time](image)

**Figure 36.** Open phase - BESS and Grounding transformer without load.

### 5.3.6.4. Recloser with single-phase trip/single-phase lockout

Single-phase trip/single-phase lockout condition occurs when three-phase industrial and commercial loads fed by three phase transformers are interrupted on a single phase due to the ground fault. After the fault has been cleared by recloser, fuse or other single-phase protective device, several unwanted consequences can occur: motor overheating (due to the voltage imbalance), transformer ferroresonance, challenges with operation of power electronic drives and voltage back-feeding on the open phase. Backfeed to fault, generally, happens regardless of the type of transformer connection. Yg-Yg transformer does not produce the backfeed to fault if either it has no load, or if all loads are line-to-ground. However, if the loads are line-to-line, especially motors, backfeed becomes an issue. Ungrounded transformer connection results in the backfeed even if it is not loaded. This configuration might not result in a large current, but it will result in
high voltage. If there are line-to-line loads connected to this transformer, and some these loads are motors, they will result in increase in the backfeed current.

As part of the analysis, LG fault was placed on phase A downstream from a recloser that was designed with single-phase trip, single-phase lock-out relay, and downstream load composition was varied with respect to the percentage of line-to-line connected motors and normal single-phase resistive load. Figure 38 shows the level of voltage on the open phase as a function of the downstream load.

As can be seen from the graph, open phase condition with proper downstream load composition can provide significant backfeed voltage, which can potentially cause the damage to other single-phase loads on the open phase, because the available voltage (which in this case is measured to be at 0.557 p.u.) to those loads is significantly less that their minimum operating voltage (which for most of the loads is 0.90 p.u.). How long will this condition persist is a function of the amount of single-phase load downstream from the open phase location and motor protection and control schemes. Even though motors can operate with loss of a phase, all motors connected to electric utility feeders must have protection against single-phasing. Typical protection scheme on motors consists of 50/51, 27, 59, and 81 elements, but the most important motor protection element is thermal overload protection which is based on voltage unbalance and current imbalance.
Open phase condition causes the voltage unbalance on motor inputs, which in turn causes the unbalanced stator currents to flow in the motor.

![Graph showing open phase backfeed voltage due to single-phase lockout.](image)

Figure 38. Backfeed voltage due to single-phase lockout.

Further analysis was done by placing the grounding transformer upstream and downstream from the open phase and recording the fault current and grounding transformer neutral current as a function of the percentage of the downstream motor load. Figure 39 shows the results of the analysis. As seen from the graph, if the grounding transformer is located upstream from the open phase, regardless of the percentage of the motor load and grounding transformer size, the neutral current within the grounding transformer is simply equal to the unbalance current.

![Graph showing neutral current for different transformer sizes.](image)

Figure 39. Grounding transformer – optimum feeder location.
If grounding transformer is located downstream from the open phase, then the higher the rating of the grounding transformer, the higher the neutral current will be flowing. As seen from the figure, there is enough margin even for the 75kVA grounding transformer above the steady-state value for the protection relay settings to detect the fault. Based on this simulation, it is obvious that the optimum location for installation of grounding transformer is at its furthest point on the feeder. This conclusion contrast with the claims in [8], which states that the optimum locations for the grounding transformer is at the source substation connected either to the power transformer leads or the substation bus.

There are three major challenges associated with placing the grounding transformer at its furthest point on the feeder. First, feeder can split into several sections, so identifying the furthest point on the feeder might be challenging. Second, if microgrid is black-started, then it must be grounded close to the source, so having grounding transformer at its furthest point would make the microgrid ungrounded until the grounding transformer is connected. In such case, feeder cables, arresters, and other high-voltage equipment would need to be rated for line-to-line voltages. Third, this solution would be capital intensive, because this would require fiber communications between grounding transformer and DER controllers and breaker/recloser relays.

5.3.7. Transient analysis

Transient analysis consists of the following sub-sections:

1. lightning,
2. motor starting,
3. capacitor bank energization and re-strike,
4. reactive load de-energization,
5. seamless islanding with $P_L \ll P_G$, and
6. ferroresonance.
5.3.7.1. Lightning

Power systems are constantly exposed to weather conditions, and lightning is a weather phenomenon that can have a major negative impact on the system reliability. For the purposes of system modelling, lightning can be considered as ideal current source with 0.2- to 1.5-μs rise time, duration of 500-200μs and typical crest in the range between 10-100kA [30]. During the lightning strike, a current surge is generated, and this causes the system overvoltage. The system parameters that have major impact on the level of the surge are line impedance, lightning current wave level and characteristics and type of the poles used in the power system design. In order to protect the system from the lightning caused overvoltages, protective devices such as spark gap, gapped surge arresters with and without current limiting blocks and metal oxide varistors (MOVs) have been developed. Lightning transient study is typically required for the transmission substations that are 115kV and above. Since the grounding transformer implementation from the standpoint of this article is at the feeder distribution level it is not necessary to do this study for this application, because the size of grounding transformer has no impact on the overvoltages caused by the lightning.

5.3.7.2. Motor starting

AC motors can be divided into two main categories: induction motors that are asynchronous and synchronous motors. These two categories differ mainly based on the way that the rotor field excitation is supplied. Induction motors have current induced in the rotor windings due to the rotation of the stator magnetic field. Synchronous motors have field excitation applied to the rotor windings. Due to this difference, two different types of motors have different starting methods, operating characteristics and protection and control schemes. There are several ways for starting the motors: low voltage motor starting contactor, across-the-line starting, reduced-voltage auto-
transformer starting, reduced voltage resistor or reactor starting, solid-state soft-starting, rotor resistance starting and adjustable speed drive (ASD) starting, which is the most commonly used AC motor control method.

![Diagram of microgrid primary bus voltage after 10hp motor start.](image)

Figure 40. Microgrid primary bus voltage after 10hp motor start.

In this case, 10hp induction motor was connected to the 277V/480V side, and the motor was started using ASD and grounding transformers of four different sizes were used in this simulation. The following Figure 40 below shows the voltage on microgrid primary side before, during and after the 10hp motor start (5% of the BESS maximum output of 150kVA). Based on the simulations, the response is the same regardless of the size of the grounding transformer. The voltage on the feeder reaches the sag of 0.84p.u. during the 10hp motor start using ASD and recovers to 1.04p.u. However, as seen from the graph, the voltage is not as stable as desired.

One additional test must be completed in order to see how the microgrid reacts to different motor sizes. For that reason, 10hp motor start was compared to 20hp motor start (in this case, 20hp represents the 10% BESS rating). The following Figure 41 below shows the difference between the start of 10hp and 20hp motor with ASD. As seen from the figure, the main difference between the two is the level of voltage sag during the motor start (0.84p.u. for 10hp motor vs. 0.79p.u. for 20hp motor).
5.3.7.3. Capacitor bank energization and re-strike

Capacitor banks are one of the most frequently used devices on the power system. Capacitor bank switching creates power quality challenges during two different operating procedures: capacitor energization and restrike. When a capacitor bank is energized, inrush current first flows from the grid to charge the capacitance. This current has high peak and damps out quickly. Capacitor bank voltage goes down to zero, and then it reaches the peak of 2.0 p.u maximum in frequencies between 300Hz and 1000Hz with several extra zero-voltage crossings before it stabilizes to a steady-state value. The number of zero-sequence crossings is a function of transformer connection, capacitor bank size, type (ungrounded vs. grounded), system impedance and X/R ratio. The term “restrike” is defined as a re-establishment of the current, one-quarter cycle or longer, following interruption of a capacitive current at a normal current zero. When capacitor breaker opens, capacitors are not discharged instantaneously, and they remain charged at the level of instantaneous voltage that they had when they were left disconnected. It occurs if the open gap dielectric strength does not have the capability to withstand the recovery voltage across the open gap. Breaker contacts now are exposed to the feeder bus sinusoidal voltage on one side and the constant capacitor voltage on the other side. If the voltage is interrupted at its zero-crossing, then
no restrike occurs. However, if the voltage is interrupted at its peak, then the restrike can cause the voltage to reach two times its peak line to ground voltage. Figure 42 below shows what happens with microgrid voltage during the capacitor bank energization using random switching using 75kVA grounding transformer connected to the microgrid.

Figure 42. Capacitor energization.

Figure 43 below shows what happens with microgrid voltage during the capacitor bank restrike during random capacitor breaker opening using 75kVA grounding transformer connected to the microgrid. Simulation was carried out for all four different sizes of grounding transformer. Capacitor bank size was calculated based on the typical average number of capacitor banks compared to the feeder voltage level, peak load and desired power factor. For the simulation purposes, maximum capacitor bank kVAR output was taken to be 0.2p.u. of the feeder maximum load, assuming the average number of capacitor banks per feeder to be four and minimum lower power factor of 0.8 lagging that could be corrected to power factor of 1. The bank was energized at the time when one of the phase voltages was at its peak. For the restrike simulation, capacitor bank was de-energized at a particular moment, and after 1-cycle, it was re-energized at the time when one of the voltages was also at its peak and then it was de-energized.
Figure 43. Capacitor bank – restrike.

Peak voltages were recorded, and results are shown in Table 17.

Table 17. Capacitor bank switching - Transient overvoltage crest factors

<table>
<thead>
<tr>
<th>kVA</th>
<th>( V_{\text{Energization [p.u.]} } )</th>
<th>( V_{\text{Restrike [p.u.]} } )</th>
</tr>
</thead>
<tbody>
<tr>
<td>75</td>
<td>1.202</td>
<td>1.267</td>
</tr>
<tr>
<td>150</td>
<td>1.260</td>
<td>1.357</td>
</tr>
<tr>
<td>300</td>
<td>1.270</td>
<td>1.375</td>
</tr>
<tr>
<td>500</td>
<td>1.274</td>
<td>1.399</td>
</tr>
</tbody>
</table>

For a solidly grounded system, maximum voltage crest factor should not exceed 1.414, which has been achieved for all grounding transformer sizes based on the results from the Table 17 above. Note that, theoretically, transient overvoltages due to the capacitor bank switching can reach 2.0p.u. level for the worst-case condition. However, capacitor bank switching rarely produces transient overvoltages higher than 1.75p.u. due to the feeder loads and dampening factor of the feeder resistive elements. However, due to the low transient frequency of capacitor bank switching, these transients can pass through the feeder step-down transformers (for example, in our case 12.47kV - 277V/480V transformer feeding the commercial or industrial customer), and cause some undesired power quality events, one of which is nuisance tripping of adjustable speed drives (ASD). For that reason, this is the additional analysis that must be performed with capacitor
switching in order to make sure that during the islanded operation mode capacitor bank operation does not cause this nuisance tripping.

Pulse-width-modulated (PWM) ASD consist of four sections: rectifier, DC link, inverter and controller. First, AC/DC rectifier is connected to the AC voltage (typically 480V/60Hz). Following, there is a DC link that consists of combination of an inductor and capacitor, used to keep the constant DC bus voltage. Because of the rectifier connection, the capacitors are effectively connected phase-to-phase. During the capacitor switching, only one half of the transient current can be seen on the DC bus because of the rectifier (the current flow in reverse direction is not possible because of the diodes in the rectifier bridge). Capacitor switching then causes the transient impulse current, typically with harmonic response in 300-1000Hz range, that charges the capacitor and causes the voltage to spike. Power transistors used in ASMs are typically rated at 1200V, and transient voltages can cause significant damage to these transistors. In order to prevent the transistor failure, the DC bus overvoltage trip level is typically set at 1.2p.u. (most common), with typical range of 1.17-1.26p.u. For the input AC voltage of \( V_{AC} = 480V \) the nominal DC bus voltage of the adjustable speed drive can be calculated as:

\[
V_{DC} = \frac{3\sqrt{2}}{\pi} V_{AC} \approx 1.35 \times 480V \approx 650V
\]

DC link is then connected to DC/AC inverter and the motor is connected to the AC side of the inverter. Controller uses the signals from the operator and equipment in order to control the operation of the motor. For the nuisance tripping evaluation, measurements and simulations proved that the inverter and the motor are not needed. Simplified representation of this part of the adjustable speed drive involves using a resistor in parallel with capacitor as shown on the Figure 44.
Equivalent resistor value for 10hp motor is then calculated as:

$$R_{motor} = \frac{V_{DC}^2}{P_{motor}} = \frac{650V^2}{7,457W} = 56.66\Omega$$

The following Figure 45 shows the adjustable speed drive DC bus voltage response to the capacitor bank switching. As seen from the graph, for this microgrid, the DC bus voltage does not reach the 1.2p.u. level that causes the nuisance trips.

![ASD DC Bus Voltage – Capacitor bank switching](image)

However, the analysis shows that grounding transformer lower kVA results in a higher DC bus voltage. ASD DC bus voltages based on this analysis are shown in Table 18. Note that this analysis was done with BESS voltage setpoint of 1.0 p.u. If the voltage set-point was raised to the typical set-point of 1.05p.u, then the ASD would trip because the DC bus voltage would have reached 1.20p.u.
Table 18. ASD DC Bus voltages

<table>
<thead>
<tr>
<th>kVA</th>
<th>$V_{dc}[V]$</th>
<th>$V_{dc}[p.u.]$</th>
</tr>
</thead>
<tbody>
<tr>
<td>75</td>
<td>747.0</td>
<td>1.150</td>
</tr>
<tr>
<td>150</td>
<td>742.3</td>
<td>1.142</td>
</tr>
<tr>
<td>300</td>
<td>733.2</td>
<td>1.129</td>
</tr>
<tr>
<td>500</td>
<td>732.6</td>
<td>1.127</td>
</tr>
</tbody>
</table>

For this reason, it is necessary to implement a solution that will solve the problem of ASD nuisance tripping. There are several ways to address the problem of nuisance tripping of ASD’s.

1. First, voltage at the DER location (BESS) is typically set to operate at $126V$, in order to ensure that the customers at the end of the feeder still have the voltage within the desired limits. One solution for nuisance tripping could potentially be to reduce the voltage at the BESS, which in turn would reduce the level of ASD DC bus voltage, but it could also result in some customers having the voltage below the required level,

2. Second, capacitor bank controlled switching techniques could be potentially implemented in order to reduce the transient voltage. Some of the techniques include staged switching, pre-insertion resistor or synchronous closing control. Typically, none of these techniques is typically implemented on the distribution feeder capacitor banks, so any of these mitigation techniques will require the design and field implementation,

3. Lastly, customer-based solutions like chokes, low voltage arresters or harmonics filters could also potentially be installed. However, due to the number of the motors on the feeder, this might not be the most cost-effective solution.

Based on all available options, second mitigation technique that involves the controlled switching at zero-voltage crossing of the capacitor banks was chosen to be implemented and the following Figure 46 shows the result. As seen from the graph, using controlled switching it is possible to reduce the transient overvoltage in this case by 10\% and bring it within the desired range.
Note that the synchronous closing control is successful only if the switches can operate with maximum deviation of $\pm 1.2ms$ from the average operating time for the capacitor switch. This operation must be repeatable over full range of temperatures and after the switch has not operated for a long period of time. There is one additional requirement for the capacitor switch that must be satisfied: rate of decrease of dielectric strength (RDDS) of the capacitor switch must be less than $\text{RDDS} < 0.7$. However, in this case the requirement might not need to apply, since the microgrid in this case is connected to a medium voltage system and RDDS requirement applies mostly to high voltage systems.

5.3.7.4. Reactive load de-energization

Loss of reactive load (namely motors) can result in voltage swell that can result in microgrid black-out. Motor load was added to the microgrid using ASD as a starting mechanism. The following Figure 47 shows the induction motor starting circuit added to the microgrid as a reactive load.

Figure 46. ASD DC Bus Voltage - Capacitor bank controlled switching.
Figure 47. Motor starting circuit.

Figure 48 shows the voltage within the microgrid during the seamless transition to island with 25hp motor running at full nameplate rating.

![Graph showing voltage within the microgrid during the seamless transition to island with 25hp motor running at full nameplate rating.](image)

Figure 48. Microgrid voltage during seamless islanding transition and 25hp motor loss.

As seen from the graph, if the largest motor within the microgrid that is running at nominal rating in grid connected mode is 12.5\% of the BESS rating, the microgrid transition will result in blackout.

5.3.7.5. Seamless islanding with $P_L \ll P_G$

One of the downside to approaches outlined in [31] and [32] is the lack of the analysis for LROV in presence of grounding transformer. This is very important analysis, because design of
grounding transformer directly affects the success or failure of microgrid islanding scheme. LROV occurs when microgrid is transitioning to the island in case when generation from DERs within the island is higher than the load. Simulations were carried out for different ratios of load and generation and for different sizes of grounding transformer. As expected, grounding transformer size does not have any effect on the LROV. For $P_L/P_G = 0.3$, microgrid voltage does not reach the second level overvoltage set-point ($59P2P = 1.2$ p.u. for more than 5 cycles) so it does not trip (note that the first level overvoltage set-point is torque-controlled during the transition to $59P1P = 1.1$ p.u. for more than 300 cycles). However, if $P_L/P_G = 0.25$, microgrid relays trip due to LROV as microgrid voltage reaches levels in excess of 3.10 p.u. (Figure 49).

![Microgrid islanding voltage response for $P_L<<P_G$.](image)

Figure 49. Microgrid islanding voltage response for $P_L<<P_G$.

Maximum bus voltages based on this analysis are shown in Table 19. Seamless islanding with different $P_L/P_G$ ratios was tested in the field within the actual electric utility’s microgrid.

<table>
<thead>
<tr>
<th>kVA rating</th>
<th>$P_L&lt;&lt;P_G$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0.3</td>
</tr>
<tr>
<td>75</td>
<td>1.19</td>
</tr>
<tr>
<td>150</td>
<td>1.19</td>
</tr>
<tr>
<td>300</td>
<td>1.19</td>
</tr>
<tr>
<td>500</td>
<td>1.19</td>
</tr>
</tbody>
</table>
As seen from the results, grounding transformer size does not have the impact on the maximum voltage during the transition to island. Field results for this simulation are shown on Figure 50 below. As seen from the figure seamless islanding fails for cases when $P_L/P_G < 0.2$ due to LROV, which is close to the simulated value of 0.25. Even though both voltage and frequency settings are torque-controlled during this transition, the voltage within the microgrid exceeds the second level overvoltage set-point ($59\text{P}2\text{P} = 1.2\text{ p.u.}$ for more than 5 cycles), which causes the relays to trip the microgrid.

![Figure 50. LROV during seamless islanding.](image)

5.3.7.6. Ferroresonance

Ferroresonance or nonlinear resonance is a type of resonance in electric circuits which occurs when a circuit containing a nonlinear inductance is fed from a source that has series capacitance, and the circuit is subjected to a disturbance such as opening of a switch. There are six different factors that affect ferroresonance during the open phase conditions: inverter capacitance, underground cable capacitance, low-loss interconnection transformer, no loading on open phase section, no grounding transformer on open phase section and higher nominal primary voltage. Ferroresonance typically occurs if the microgrid is ungrounded, not effectively grounded (i.e. the
size of grounding transformer is too small) or in part of the microgrid with little or no resistive load connected during the open phase condition. Figure 51 shows the ferroresonance within the microgrid without grounding transformer under the open phase condition occurring at 2.5 seconds. As seen from the figure, phase-to-phase voltage reaches approximately 4 p.u. value, which causes the microgrid to enter the ferroresonance state.

![Figure 51. Ferroresonance within the microgrid without grounding transformer.](image)

Following, open phase was simulated between the DER inverter AC side and 1000kVA transformer, and results are shown on Figure 52. As seen from the graph, the addition of grounding transformer reduces the chances of ferroresonance, as well as the minimal load.

![Figure 52. Ferroresonance as a function of loading and grounding transformer rating.](image)
As seen from the graph, voltage on phase A stabilizes to 1.09 p.u., so in case when the microgrid does not have any load within the area where open phase occurs, but there is a grounding transformer connected, there is no case for ferroresonance.

In order to check the worst case for ferroresonance, which involves no loading and no grounding transformer on open phase section, simulation was carried out and Figure 53 shows the results of this analysis. As seen from the graph, even though there is no ferroresonance, microgrid loads can potentially experience phase overvoltages up to 1.64p.u. that can severely damage any phase-to-ground equipment.

![Figure 53. Microgrid voltage during open phase A condition without grounding transformer.](image)

Note that Figure 53 is misleading, because the simulation shows phase-to-ground voltage measurements, which are not actual phase-to-ground voltages, because the microgrid is ungrounded. Under those conditions, measuring phase-to-phase voltages is more appropriate, and those values should be used in assessing the severity of the overvoltages during the open phase condition. In addition, all relays within the microgrid would need to be torque-controlled to switch over to $V_{LL}$ set-points. Otherwise, simply transitioning to islanded mode of operation without grounding transformer can result in a microgrid black-out, because $V_{LN}$ voltage can exceed the first level overvoltage setting ($59P1P = 1.10p.u.$).
5.3.8. kVA rating

When Yg-Δ transformer is used as a grounding bank, the short-time kVA rating of this transformer is calculated as:

\[ kVA = \frac{V_{LL} \times I_N}{\sqrt{3}} \]

During normal operation, grounding transformer only carries the unbalance current and has no load, so it is common to rate the grounding transformer for continuous rating. During the ground fault conditions, grounding transformer carries the fault current and it is common procedure to rate the grounding transformer on a short-time, such as 10 seconds. In this way, grounding transformer can be built as a smaller and more cost effective unit with higher kVA rating for short-time operation. This rating is based on the maximum neutral current seen during any ground fault (in our case, that is 31.28A).

\[ kVA_{SC MAX} = \frac{V_{LL} \times I_N}{\sqrt{3}} = \frac{12.47kV \times 31.28A}{\sqrt{3}} = 225kVA \]

Note that this rating is representative of the current microgrid requirements. Grounding transformer should be rated slightly above this value, so multiplier of 1.5 can be added to the rating. From here, new grounding transformer kVA short-term rating can be calculated as:

\[ I_{SC MAX} = 1.5 \times I_{SC MAX} = 1.5 \times 31.28A = 46.92A \]

\[ kVA_{SC MAX} = \frac{V_{LL} \times I_N}{\sqrt{3}} = \frac{12.47kV \times 46.92A}{\sqrt{3}} = 337.5kVA \]

Now, Table 20 shows the simulations-based microgrid grounding transformer short-term current rating.

<table>
<thead>
<tr>
<th>Rated time</th>
<th>Short-circuit rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 seconds</td>
<td>1.5*(I_{SC MAX}) (46.92A or 337.5kVA)</td>
</tr>
</tbody>
</table>
The following Table 21 shows the comparison between the three methods for grounding transformer designed outlined in this chapter.

Table 21. Grounding Transformer design - Comparison

<table>
<thead>
<tr>
<th>Design parameter</th>
<th>IEEE C62.92</th>
<th>IEEE 1547.8</th>
<th>New method</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manufacturer</td>
<td>ABC</td>
<td>ABC</td>
<td>ABC</td>
</tr>
<tr>
<td>Serial number</td>
<td>123456</td>
<td>123456</td>
<td>123456</td>
</tr>
<tr>
<td>Name of Transformer</td>
<td>Grounding</td>
<td>Grounding</td>
<td>Grounding</td>
</tr>
<tr>
<td>Type designation</td>
<td>Yg-Δ</td>
<td>Yg-Δ</td>
<td>Yg-Δ</td>
</tr>
<tr>
<td>Impedance (Z₀)</td>
<td>560 Ω/phase</td>
<td>Rg≤93.3Ω &amp;</td>
<td>0 Ω/phase</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Xg=373.2Ω</td>
<td></td>
</tr>
<tr>
<td>Number of phases</td>
<td>3</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>Resistance Temp. coeff. @ 25°</td>
<td>75°</td>
<td>75°</td>
<td>75°</td>
</tr>
<tr>
<td>Rated continuous neutral current</td>
<td>38.23kVA</td>
<td>4.32kVA</td>
<td>57.75kVA</td>
</tr>
<tr>
<td>Rated short time thermal current</td>
<td>132.97kVA</td>
<td>500kVA</td>
<td>337.5kVA</td>
</tr>
<tr>
<td>Rated frequency</td>
<td>60Hz</td>
<td>60Hz</td>
<td>60Hz</td>
</tr>
<tr>
<td>Rated time</td>
<td>Short-term, Continuous</td>
<td>Short-term, Continuous</td>
<td>Short-term, Continuous</td>
</tr>
<tr>
<td>Rated voltage</td>
<td>12.47kV (primary)</td>
<td>12.47kV (primary)</td>
<td>12.47kV (primary)</td>
</tr>
<tr>
<td>Rated voltage (secondary)</td>
<td>480V (secondary)</td>
<td>480V (secondary)</td>
<td>480V (secondary)</td>
</tr>
<tr>
<td>BIL of &quot;line&quot;</td>
<td>110kV</td>
<td>110kV</td>
<td>110kV</td>
</tr>
<tr>
<td>Service</td>
<td>Outdoor</td>
<td>Outdoor</td>
<td>Outdoor</td>
</tr>
<tr>
<td>Mass</td>
<td>4800 lbs</td>
<td>4800 lbs</td>
<td>4800 lbs</td>
</tr>
<tr>
<td>Volume of liquid</td>
<td>200 gal</td>
<td>200 gal</td>
<td>200 gal</td>
</tr>
<tr>
<td>Year of manufacture</td>
<td>2019</td>
<td>2019</td>
<td>2019</td>
</tr>
</tbody>
</table>

Looking at the three approaches, there is a significant difference in impedance (Z₀), short-term and continuous rating. Implementing any impedance (Z₀) in this case is not advisable, because of two major negative impacts to the safe and reliable operation of the microgrid:

1. It reduces the amount of available fault current, which is already low to begin with, and
2. It increases the voltages on un-faulted phases during the ground faults, which makes the effective grounding within the microgrid challenging, because the voltage on un-faulted phases can easily be over 1.38 p.u.

In addition, calculated continuous neutral current using the IEEE 1547.8. based method is so low that the grounding transformer would fail even on a normal operating mode as seen from the recorded values of neutral current under the normal operating conditions on Figure 27. Similarly, short-time thermal current rating using the IEEE C62.92. method is also low, that the transformer
would fail during the ground fault conditions. New method provides significant advantage over the existing two methods, because it is both iteration-based as well as simulations-based, while the other two methods are simply calculations-based.
CHAPTER 6: Grounding Transformer Protection and Control Scheme

6.1. Grounding transformer protection - background

As noted before, there are several IEEE standards that reference the neutral grounding of electrical utility systems. Similarly, there are several IEEE Standards that reference the protection and control schemes for a substation transformer. However, there is no existing standard today that outlines the procedure for the design of the protection and control scheme for grounding transformer operating as part of the microgrid in islanded mode with inverter-based DERs. Additionally, existing transformer protection and control standards cannot be applied in this case because of several competing and contradicting conditions. Review of the current literature shows very few papers written on this topic. Authors in [33] provided the background on grounding transformers, types, operation but provide no design and protection philosophy. In [34] authors assessed the grounding transformer connection methods used within electric utility feeders that have distributed generation (DG) connected to it and outlined criteria for additional protection that might be needed. However, the only DG considered was the small back-up generator, which on its own does not require grounding transformer. Authors in [18] examined the temporary overvoltage and ground potential rise on the distribution feeders with multi-grounded neutral wire. However, the authors did not provide any insight into the application of grounding transformer on these feeders, and its effect on the two mechanisms. In [35], authors examined the impact of primary grounding on the low voltage network ground fault currents, un-faulted line-to-line voltages and voltage sags. Authors also proposed the addition of neutral grounding impedance, reactance grounding, resistance grounding, and the addition of grounding bank. However, the authors never considered the addition of DERs to the feeder and its impact on their analysis. Authors in [36] proposed the use of high-resistance grounding for a large industrial customer with two back-up
generators. However, the authors did not provide any analysis regarding the use of inverter-based DERs as back-up generation, because high resistance grounding would not provide the proper solution in that case. In [37], authors provided the analysis with respect to line-to-ground faults in cases when grounding transformer is connected on the Y-grounded distribution feeder. However, the article does not provide any insight into the design of the grounding transformer protection and control. Authors in [38] provided the overview of microgrid protections and grounding and proposed the use of grounding transformer operating in grid-connected mode or using the grounding methods that includes the impedance. Both approaches have shortcomings that reduce the security of the protection and control microgrid scheme. In [23], authors examined the microgrid protection and control scheme based on synchronous-based DG units, which is much less complex compared to the system that uses inverter-based DGs. Authors in [39] proposed the use of D-STATCOM in order to mitigate the voltage imbalance, but the proposed microgrid, which consists of inverter-based DERs, does not include grounding transformer. In [40], the authors provided the overview of challenges associated with properly grounding the microgrid, without going into specific analysis of any of the issues.

There are many standards and system practices that provide the guidance to the transformer protection and control in general. In this case, the design of reliable and secure microgrid protection and control scheme is more challenging, because of the two reasons. First grounding transformer does not carry any load, so traditional overcurrent (50/51) and differential protection (87) cannot be reliably implemented. Second, fault current levels within the microgrid are significantly lower (traditionally in 1.2-1.4p.u., even though the BESS inverter at this electric utility’s microgrid can provide up to 2.4p.u. of fault current) when it operates in islanded mode compared to the grid connected mode. For that reason, detecting the internal grounding transformer faults such as turn-
to-turn faults or winding-to-tank/ground faults near the star point of the Y winding, that are challenging to recognize even in grid connected mode, is even more challenging. As noted before, substation transformer typically acts as a grounding source for downstream feeders. In addition to traditional protection, this transformer also has a neutral CT installed between the neutral of the Yg side and ground. This element acts as a back-up protection for the downstream ground faults and its pick-up and time-delay settings coordinated with downstream overcurrent protection. Given that the grounding transformer within the microgrid has multiple purpose, its protection and control scheme must be more sophisticated compared to the traditional protection. Figure 54 shows the implementation of a Yg-Δ grounding transformer within the microgrid (this transformer is rated at 500kVA). Like the traditional substation transformer protection, this figure also shows the transformer with neutral CT installed within.

![Grounding transformer (Yg-Δ) field implementation.](image)

Figure 54. Grounding transformer (Yg-Δ) field implementation.

Figure 55 below shows the one-line diagram associated with the new proposed scheme for grounding transformer protection and control that will be discussed in this chapter.
Figure 55. New Grounding transformer protection and control scheme – single-line diagram

Figure 56 shows the new proposed protection and control methodology for grounding transformer along with the proposed relays, their functionality with respect to protection elements and proposed fault testing locations. The protection consists of two relays – SEL 787, which is a transformer differential relay, and SEL 751, which is feeder overcurrent relay. In the new proposed scheme, these relays will be used differently compared to the traditional protection.

Figure 56. Grounding transformer protection and control scheme - area of protection.
Faults F1 and F2 represent the grounding transformer internal faults (winding-to-tank/ground and winding-to-winding). Fault F3 is the internal fault within the other transformer on the feeder (in this case BESS GSU transformer), and fault F4 is the fault on the feeder primary. It is expected that the grounding transformer protection will be able to detect its internal faults (F1 and F2) and act as a back-up protection for the faults outside of its protection zone (F3 and F4). Figure 55 shows the single-line diagram with all protection elements for the grounding transformer.

Figure 57 shows the three-line diagram with two proposed relays SEL 787 and SEL 751 along with their proposed CT and PT connections and digital inputs as the new grounding transformer protection and control scheme. SEL 787 relay is used for detection of:

1. Grounding transformer internal winding-to-tank/ground faults on Yg side,
2. Grounding transformer inrush current protection,
3. Feeder internal transformer faults on primary side,
4. Ground faults (LG and LLG) - back-up protection.

SEL 751 relay is used for detection of grounding transformer:

1. Internal winding-to-tank/ground faults on secondary (Δ) side,
2. Internal winding-to-winding faults on secondary (Δ) side, and
3. Internal faults detected by mechanical devices.

Figure 57. New Grounding transformer protection and control scheme.
The only part of the protection and control scheme missing on the drawing are the ALARM and TRIP digital output signal for both relays. TRIP digital outputs are hardwired to the SEL 487E relay associated with both 4-way switchgear and BESS, while ALARM digital outputs are sent to the microgrid controller to be displayed on SCADA screen.

6.1.1. **Grounding transformer internal faults on Yg side**

Table 22 shows the new design of the grounding transformer protection and control which is designed to detect the transformer internal faults on both primary (Yg) and secondary (Δ) side using the input from electrical quantities (voltage, current, etc...). In order to sense transformer internal faults on the Yg side, a form of differential protection called restricted earth fault (REF) is proposed in this case along with couple of torque-controlled overcurrent elements. REF protection is a form of current differential protection where the sum of the currents in three phase CTs entering the Yg side of the grounding transformer must be equal to the current measured by the neutral CT between the neutral and the ground. In case of an internal ground fault within the Yg side of the grounding transformer, this condition does not hold anymore, and the 87N protective element should detect this condition. REF protection can be implemented only in cases where grounded transformer is grounded through resistance or solidly grounded.

<table>
<thead>
<tr>
<th>Protection element</th>
<th>Fault</th>
<th>Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>87N TC (3I_0 - I_N)</td>
<td>REF</td>
<td>Internal (Yg)</td>
</tr>
<tr>
<td>3(V_0) TC (V_{PH}) (27P)</td>
<td>Winding-tank</td>
<td>Internal (Δ)</td>
</tr>
<tr>
<td>27PP</td>
<td>Winding-Winding</td>
<td>Internal (Δ)</td>
</tr>
</tbody>
</table>

In order to implement this solution, three phase CTs with 200:5 ratio and neutral CT with 50:5 ratio were installed on the grounding transformer in these currents were wired into the analog CT input card of SEL 787 relay. First, setting for the protection element called 50REF1P must be calculated and it must be greater of the following:
1. Residual current imbalance resulting from the changing load conditions - maximum neutral current imbalance was found to be 2.72A during the load flow analysis, and for that value, the maximum grounding transformer phase currents was simulated to be 1.22A.

2. Current minimum value based on the 50:5 neutral CT ratio – this ratio is calculated as:

   \[
   50\text{REF1P (sec Amps)} = \frac{1.22A}{50:5} = 0.122A
   \]

   Since both CTs have output of 5A, the per unit value for the 50REF1P is:

   \[
   50\text{REF1P (sec p.u.)} = \frac{0.122A}{5A} = 0.025\text{p.u.}
   \]

3. Since no two CTs are ever built the same, saturation curves, cable impedance and other factors can affect the security of the scheme, where protection and control can erroneously issue breaker trip command; for that reason, it is necessary to calculate the sensitivity of the neutral CT winding (\(CTR_N\)) compared to the sensitivity of the phase CT winding \(CTR_{PH}\):

   \[
   50\text{REF1P (sec p.u.)} \geq 0.05 \times \frac{CTR_{PH} \times I_{NOM\ PH}}{CTR_N \times I_{NOM\ N}} \geq 0.05 \times \frac{200 \times 5}{50 \times 5} \geq 0.2 \text{ p.u.}
   \]

   50REF1P must be greater of the two values, so the final setting for 50REF1P = 0.2p.u. where 1.0p.u. is 5A with time-delay of \(t_D = 30\) cycles. Figure 58 shows the current flow within the grounding transformer for an internal winging-to-tank/ground fault. The only downside to the REF (87N) protection and control scheme is that the 87N element can erroneously trip for the phase-to-phase faults outside its protection zone (on the microgrid side).

   There are two improvements that are needed in order to increase the security and reliability of this scheme. Figure 58 shows the current flow for internal faults. If the fault is external, then the fault current will enter the polarity side of the neutral CT go through the transformer and enter the non-polarity side of phase CTs.
Figure 58. Grounding transformer current flow - internal winging-to-tank/ground fault.

If the fault is internal, then one part of fault current will enter the polarity side of phase CTs, while the second part of the fault current will enter the polarity side of neutral CT. Following two torque-control elements are proposed in order to increase the security of this scheme:

1. Directional element REFTQ:

   \[ REFTQ = Re[(3I_0* I_N)^*] = -3I_0* I_N* cos\phi \]

   where, \( 3I_0 = I_A + I_B + I_C \) and \( \phi \) is the angle between the polarizing quantity \(-3I_0\) and operating quantity \(I_N\). As a result,

   \[ REFTQ \begin{cases} > 0, & \text{if } \angle \phi \text{ is within } \pm 90^\circ \\ < 0, & \text{if } \angle \phi > +90^\circ \text{ or } \angle \phi < -90^\circ \end{cases} \]

   If \( REFTQ > 0 \), then the fault is internal and element 87N will operate if other conditions are met. If \( REFTQ < 0 \), then the fault is external, and 87N will not operate (however, 51N element might operate in this case). REFTQ time delay in this case is chosen to be 1.5 cycles.

2. Traditional transformers have loading that is large enough that both magnitude and angle measurements for \(-3I_0\) and \(I_N\) are easily available. However, this is not the case with grounding transformer, because this transformer does not carry any load. Under the normal operating conditions, operating quantity \(I_N\) carries the unbalance current, which is measured to be 2.72A at its maximum (see Figure 59), and phase current maximum value is 1.22A.
So, in order to enable the 87N scheme, second two restraining elements consist of the following:

\[
50N5P = 115\% \times I_{NMAX} = 115\% \times 2.72A = 3.13A \\
50P5P = 115\% \times I_{NMAX} = 115\% \times 1.22A = 1.40A
\]

Time delay in this case has been chosen as 10 cycles.

3. This scheme can also result in erroneous trip for one of the transient conditions - grounding transformer energization. As described before, the maximum current value for the grounding transformer energization will vary depending on the moment of energization and the authors propose blocking 87N element during the grounding transformer energization, so the same logic as before must be implemented as part of this scheme.

Fault F1 was placed between the phase A and the tank/ground within the grounding transformer, and winding depth was varied in order to determine the area of protection for REF element and the depth of primary Yg winding that can be protected. Figure 60 shows the results of the study with fault F1 moving from 0-25\% (left side) to 30-100\% (right side) of the depth of the winding.
Based on the analysis, the following is the set of conclusions that can be derived:

1. REF element can properly protect the microgrid from grounding transformer internal faults for 30% - 100% of the primary winding,

2. If the fault is within the first 30% of the depth of the winding, the fault detection element 87N chatters, and as seen from the graph, it changes from 0 to 1 several times. For that reason, the TRIP element might or might not pick up, which negatively impacts the security and reliability of this scheme,

3. Security and reliability of the scheme improve with larger percentage of the winding affected by the fault,

4. Undervoltage (27) and overvoltage (59) protection elements cannot be reliably and securely used for this protection, because the phase undervoltage values are very close to the 27P1P setting as fault gets closer to neutral,

5. The same conclusion hold for the voltage sequence networks (\(V_1, V_2\) and \(V_0\)).
6. 87N element detects the internal fault based on the 50REF1P setting and it enables the logic that performs the directional calculations; the logic results in REFTQ element value based on the Figure 61 below that shows the phase angles for $I_N$ and $3I_0$ before and during the fault.

![Diagram of phase angles](image)

**Figure 61. Phase angles for $I_N$ and $3I_0$ before and during the fault.**

As seen from the graph, prior to the fault (when 87N is still de-asserted), the angle for $I_N$ is a reference angle and it does not change, while the angle for $3I_0$ changes, as it rotates counterclockwise (CCW). Once the internal fault occurs, (87N asserts), both angles for $I_N$ and $3I_0$ start rotating CCW, but the angle difference between the two stays within ±90°. Once this condition occurs for 1.5 cycles, the FWD_DIR/REF1F element asserts, and at the same time, the relay calculates the torque-control element IN TC, which checks that the neutral current has exceeded the 50N5P setting. When all these conditions are met, the SEL 787 relay issues TRIP command. However, in order to increase the security and reliability of this scheme, the 87N element with 50REF1P overcurrent pick-up setting with U4 curve, time dial of 0.5 and reset time of 1 cycle has been chosen as the preferred element. As seen from the graph, the relay will issue TRIP signal 435ms after the FWD_DIR/REF1F signal. As a side note, SEL relay element for 87N element is REF1E, element for FWD_DIR is REF1F and U4 curve is REF1P element.
6.1.2. **Grounding transformer inrush current protection**

Grounding transformer inrush protection scheme is slightly different from the normal transformer protection scheme, since there is no differential protection (87) on this transformer. For that reason, transformer differential blocking scheme is not needed in this case. In general, any transformer energization causes the flow of large magnetizing inrush currents, which can cause the overcurrent element to pick-up. However, these currents contain even harmonics that can be used to block the potential mis-operation that might be caused by overcurrent elements. Typically, presence of second ($I_{F2}$) and fourth ($I_{F4}$) current harmonic above 15% of the fundamental current ($I_{F1}$) and fifth ($I_{F5}$) current harmonic above 10% are strong indication that the transformer is being energized. However, there is another challenge associated with grounding transformer energization as part of the microgrid with BESS and PV as the main DERs.

Grounding transformer is energized in two ways, depending on the feeder operating conditions. First, if the seamless transition to island is intentional, then grounding transformer is energized before the transition to island control algorithm is initiated. This is very important point, because if the grid is alive (i.e. there is no fault), and after PCC opens grounding transformer is switched onto ground fault (Figure 62), the PCC becomes exposed to high voltages between its grid and microgrid side. This happens because grid is grounded and microgrid is ungrounded with a ground fault.

![Diagram](image)

Figure 62. Microgrid transition – PCC opens and LG fault occurs on ungrounded microgrid.
Simulations were ran for this condition, and they showed that the maximum voltage withstand rating reaches 3.553 p.u. as seen on Figure 63. 15kV breakers/reclosers are typically rated for 45kV wet withstand voltage rating and 50kV dry rating. Using 3.553p.u. simulation value, it becomes obvious that the PCC could potentially fail, because its withstand voltage rating would have been exceeded (15kV * 3.553p.u. = 52.5kV, which is greater than its 50kV rating).

![Figure 63. PCC withstand voltage during LG fault.](image)

Second, if the seamless transition to island is un-intentional (i.e. there is a fault on the feeder), then grounding transformer is energized after the transition to island (i.e. PCC = OPEN). Situation is the same if the microgrid is black-started. This distinction is important because the authors now propose the torque control of the proposed protection and control scheme for transformer inrush current based on the energization mode. This is done because the transformer inrush current, when energized from the grid, is significantly higher than when the same transformer is energized from the inverter-based DERs in islanded mode.

Transformer inrush current value depends on the voltage point of wave switching angle, residual flux of the transformer and X/R ratio of the supplying source. Figure 64 shows the values for the 12.47kV, 500kVA grounding transformer inrush current levels as a function of grid-connected vs. islanding mode energization. As seen from the graph, the maximum inrush current during the grid connected mode reached 19.35 p.u., while the maximum inrush current in islanded
mode reached 0.91p.u using the breaker with gang-operated mode. This is a major difference from traditional approach to transformer inrush current protection scheme, because inverter based DERs cannot produce the same inrush current levels.

![Graph showing grounding transformer inrush current during energization](image)

Figure 64. Grounding transformer inrush current during energization.

So, the new scheme now includes the torque-controlled approach to the grounding transformer inrush current, because keeping one set of settings would not properly protect the grounding transformer during the energization. Based on the additional research work that the author has conducted, when operating in islanded mode, transformer energization using traditional gang-operated breaker/recloser, results in voltage sag of anywhere between 3-49%, which is not acceptable, because Rapid Voltage Change (RVC) factor, as defined by [41], might not be achievable. For that reason, B2 breaker was replaced with a 15kV single pole operation Control Switching Device (CSD) with closing response time within $T_D \pm 1.2ms$, where $T_D$ is the average CLOSE operation time of each breaker pole (typically around 70ms in this case). The controller was implemented to minimize the transformer inrush current based on the measured residual
magnetism. As seen from the graph, that approach even further reduces the transformer inrush current. The following Table 23 shows the field results during grounding transformer energization.

The new protection of the grounding transformer for inrush current is now based on the torque-control of the overcurrent protection element with second and fifth current harmonic blocking, with the additional torque-control based on the overcurrent settings, PCC status and mode of operation of the grounding transformer energizing breaker (gang-operated vs. CSD operation based on residual magnetism).

Table 23. Grounding Transformer Inrush Current

<table>
<thead>
<tr>
<th></th>
<th>Grid connected</th>
<th>Grid connected w/ CSD</th>
<th>Islanded</th>
<th>Islanded w/ CSD</th>
</tr>
</thead>
<tbody>
<tr>
<td>( I_{\text{Min}} ) [p.u.]</td>
<td>0.86</td>
<td>0.17</td>
<td>0.05</td>
<td>0.05</td>
</tr>
<tr>
<td>( I_{\text{Avg}} ) [p.u.]</td>
<td>6.62</td>
<td>0.56</td>
<td>0.35</td>
<td>0.09</td>
</tr>
<tr>
<td>( I_{\text{Max}} ) [p.u.]</td>
<td>19.35</td>
<td>1.65</td>
<td>0.78</td>
<td>0.31</td>
</tr>
</tbody>
</table>

The reason for choosing 2\(^{\text{nd}}\) and 5\(^{\text{th}}\) current harmonic is due to the fact that any transformer inrush current is rich in 2\(^{\text{nd}}\) current harmonic, while 5\(^{\text{th}}\) current harmonic is chosen in order to increase the security of the protection scheme because the CT saturation during faults also results in harmonic current content. The following protection for grounding transformer inrush current was implemented within SEL relay.

First, 2\(^{\text{nd}}\) and 5\(^{\text{th}}\) current harmonic blocking elements were defined as shown in Table 24. The pickup value for 2\(^{\text{nd}}\) (HBL2P) and 5\(^{\text{th}}\) (HBL5P) harmonic of 15% works for nearly all power systems and typically, 5\(^{\text{th}}\) harmonic setting is set lower than the 2\(^{\text{nd}}\) harmonic. Pick-up delays (HBL2PU, HBL5PU) of 0 seconds result in harmonic content of each cycle for each of the phase currents being continuously evaluated. Drop-out delays (HBL2DO, HBL5DO) of 10 seconds enable both blocking elements to be triggered once per every 10 seconds, because during some faults a high second harmonic content can be created. 10 second delay, as designed, allows the
elements to still trip during this condition. Following, an SELogic variables and timers needs to be set to assert on the rising trigger when both 2\textsuperscript{nd} and 5\textsuperscript{th} harmonic blocking bit assert. The time delay settings are based on the sub-transient part of the transformer inrush current characteristics and on an average, it takes up to 100ms for the inrush current to decay.

Table 24. Grounding Transformer Inrush Current - 2\textsuperscript{nd} and 5\textsuperscript{th} harmonic element

<table>
<thead>
<tr>
<th>Harmonic settings</th>
<th>2\textsuperscript{nd} Harmonic</th>
<th>5\textsuperscript{th} Harmonic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enable blocking</td>
<td>EHBL2 := Y</td>
<td>EHBL5 := Y</td>
</tr>
<tr>
<td>Pick-up [%]</td>
<td>HBL2P := 15</td>
<td>HBL5P := 10</td>
</tr>
<tr>
<td>Pick-up delay [s]</td>
<td>HBL2PU := 0.00</td>
<td>HBL5PU := 0.00</td>
</tr>
<tr>
<td>Drop-out delay [s]</td>
<td>HBL2DO := 10</td>
<td>HBL5DO := 10</td>
</tr>
<tr>
<td>Enable TC</td>
<td>HBL2TC := 1</td>
<td>HBL5TC := 1</td>
</tr>
</tbody>
</table>

For that reason, the pick-up delay for SV timer (SV01PU) is set to 0s and the drop-out delay (SV01DO) is set to a value higher than 100ms, which in this case is 7 cycles or 112ms. Finally, the SV value (SV01) must be set to trigger on the rising edge of the 2\textsuperscript{nd} and 5\textsuperscript{th} harmonic relay word bits HBL2T and HBL5T. That is accomplished using the following expression: SV01 := R _TRIG HBL2T AND R TRIG HBL5T (see Table 25).

Table 25. Grounding Transformer Inrush Current - SV Logic/Timers

<table>
<thead>
<tr>
<th>SV Timer [s]</th>
<th>SV01PU := 0</th>
<th>SV01DO := 10</th>
</tr>
</thead>
<tbody>
<tr>
<td>SV Input</td>
<td>SV01 := R _TRIG HBL2T AND R TRIG HBL5T</td>
<td></td>
</tr>
</tbody>
</table>

The last part of the logic includes using the SV01T timer output to block the overcurrent phase elements (51AP, 51BP, and 51CP) when it is asserted for a period of 112ms or 7 cycles. This allows the overcurrent elements to ride through inrush, while not being indefinitely disabled. How are the overcurrent settings defined? Typically, for transformers with capacity less than 2500 kVA, the inrush current is taken to be 8 times the nominal full load current at 0.1 seconds, and the overcurrent pickup is set to be greater than 1.3 times the transformer inrush point at 0.1 seconds in order to avoid breaker tripping (if the measured current filters out all harmonics and DC offset). However, in this case, there is no load on the grounding transformer, so the maximum current is
the inrush current based on the Figure 64. Following, simulations and field verification were performed in order to determine the maximum value of the decaying transformer inrush current 112ms after the transformer inrush current had reached the peak. Based on the analysis and field verification, maximum transformer inrush current measured 112ms after its peak value was 50% of the peak value. Now, the overcurrent setting for grid connected grounding transformer energization for each phase can be calculated as:

$$50\text{AP} [\text{A}] = 1.3 \times 50\% \times I_{\text{max}} = 1.3 \times 50\% \times 19.35\text{p.u.} \times 23.15\text{A} = 291.2\text{A}$$

In order to implement the proposed second torque-control element, PCC breaker (B1) and breaker B2 (breaker that energizes the grounding transformer) status points (52a) must be wired into digital inputs IN101 and IN102. Controlled switching (CLOSE command) of breaker B2 is done by a separate controller, so additional communication needs to be established between this controller and relay that controls breakers B1, B2, B3 and B4 (which in this case is SEL 487E). User through the microgrid controller determines the mode of operation of breaker B2 (GO - gang operated or CSD individual phase operation based on the grounding transformer residual magnetism). Remote bit RB01 in SEL 487E relay is set to receive the information from the controller if B3 is operated as GO device (RB01 = 0) or CSD (RB01 = 1).

<table>
<thead>
<tr>
<th>Mode</th>
<th>GC</th>
<th>GC/CSD</th>
<th>Island</th>
<th>Island/CSD</th>
</tr>
</thead>
<tbody>
<tr>
<td>51AP [A]</td>
<td>291.2</td>
<td>23.8</td>
<td>11.7</td>
<td>4.7</td>
</tr>
<tr>
<td>51ATC</td>
<td>U3</td>
<td>U3</td>
<td>U3</td>
<td>U3</td>
</tr>
<tr>
<td>51ATD</td>
<td>3.00</td>
<td>3.00</td>
<td>3.00</td>
<td>3.00</td>
</tr>
<tr>
<td>51ATC (GC)</td>
<td>!SV01T AND IN101 AND IN102 AND !SV02T</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>51ATC (GC/CSD)</td>
<td>!SV01T AND IN101 AND IN102 AND SV02T</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>51ATC (Island)</td>
<td>!SV01T AND !IN101 AND IN102 AND !SV02T</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>51ATC (Island/CSD)</td>
<td>!SV01T AND IN101 AND IN102 AND SV02T</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Programming SV02 := RB01 without any delays in SEL 487E provides the variable that is needed for the torque-control. Table 26 shows the overcurrent settings along with the torque-control equations.

Figure 65 below shows the grounding transformer inrush current during energization for GC/CSD case. Top figure shows all three phase currents, while the middle figure shows only the magnitude of the phase currents. As seen from this figure, even though the 51BP overcurrent element picks up based on the curve and time-delay settings, the relay does not issue the TRIP command, because the SV01T element is asserted, since 2nd and 5th current harmonics exceed their settings. Field results show that the inrush current decay can be as long as 2 seconds if the grounding transformer is energized using GO method.

![Current waveforms](image)

6.1.3. Feeder internal transformer faults on primary side

Transformers within the microgrid can experience internal faults. On a traditional feeder, high-side fuses are used to clear these faults. However, microgrids with inverter-based DERs have low fault currents, so during internal transformer faults, these fuses cannot clear the fault (typically, these fuses are rated up to 2.5p.u. of the nominal transformer rating and above the transformer overload curve, which is also much higher than the fault current capability of the inverter-based...
DERs). For that reason, new approach is needed in order to try to protect the transformers within the microgrid from the internal faults on the Yg side. Even though there are many factors that determine the effectiveness of any new proposed scheme, such as feeder length, impedance to the fault, transformer impedance, etc, the new proposed scheme consists of the following element – phase undervoltage element $V_{LN}(27P1P)$ torque-controlled by the angle difference between the grounding transformer residual current and neutral current $\angle(3I_0 - I_N)$. For the simulation purposes, the internal transformer fault on Yg side has occurred either on the feeder transformers or at BESS or PV transformers as described by fault F3 on Figure 56. When internal transformer ground fault (on primary Yg side) occurs on the feeder, the voltage on the feeder (in this case the proposed protection element is phase undervoltage element $V_{A,B,C}$) decreases and at the same time, the current through the grounding transformer reverses its direction. The new proposed scheme measures the undervoltage condition, which is typically setting of $27P1P=0.85$pu. and it waits for the notification that the grounding transformer current has reversed its direction. Under the normal operating conditions, small magnetization current flows through the grounding transformer primary. The current flows into the polarity side of phase CTs and non-polarity side of neutral CT. This creates the phase angle difference that is tracked by the reverse direction REV DIR element (REF1R) within the SEL 787 relay as seen on Figure 66.

Figure 66. REV DIR/REF1R element before and during external fault.
Upon the external fault occurrence, the current through the grounding transformer reverses the flow as it flows from the ground to the polarity side of neutral CT, through the grounding transformer and through the non-polarity side of phase CTs. Once this condition occurs, REV DIR/REF1R element picks up and if the undervoltage condition exists for $V_{A,B,C}$ element, the relay will send TRIP command to current is within its maximum range (2.72A). During the external ground fault at F3, both phase and neutral current exceed these levels, and the phase angle difference between the $3I_0$ and $I_N$ becomes either greater than +90° or less than -90°. When this occurs, REV DIR/REF1R picks-up, and when undervoltage condition (in this case phase A voltage 27P1 element goes below 0.85p.u.) picks up, the SEL 787 relay will send TRIP command to the 4-Way switchgear relay only after time delay. Note that the internal transformer faults are detected by the differential relay if one is installed (in our case SEL 487E) for both BESS and PV transformers, but in case of the relay failure/malfunction or in case of the fault on other feeder transformers that do not have the differential relay, the SEL 787 relay will be able to detect this condition.

This protection can detect the LG and LLG faults, but it is not capable of detecting LL and 3Φ faults, because those faults do not have zero-sequence current component. The following Table 27. shows the summary of the fault current analysis based on the proposed protection, using the previously calculated settings for REF and 27P1P = 0.85p.u. setting for phase undervoltage element (for the purposes of the simulation, phase undervoltage time-delay element was set at 27P1TD = 100ms):

<table>
<thead>
<tr>
<th>Fault type</th>
<th>Winding depth [%]</th>
<th>27P TC REF1R</th>
</tr>
</thead>
<tbody>
<tr>
<td>LG</td>
<td>30-100</td>
<td>TRIP</td>
</tr>
<tr>
<td>LL</td>
<td>0-100</td>
<td>-</td>
</tr>
<tr>
<td>LLG</td>
<td>30-100</td>
<td>TRIP</td>
</tr>
<tr>
<td>3Φ</td>
<td>0-100</td>
<td>-</td>
</tr>
</tbody>
</table>
From the table, we can conclude that the proposed protection works in this for both LG and LLG faults and that it covers 70% of the BESS transformer Yg winding side. This is the best case scenario, as the first 25% of the winding depth cannot be securely and reliably protected, because of the inherent inaccuracies with CT build and low fault currents. Figure 67 below shows the response of the phase undervoltage elements (27P1P) as a function of the angle difference between the grounding transformer residual current angle $\angle 3I_0$ and neutral current $\angle I_N$ during the winding-to-tank/ground fault within the BESS transformer (F3).

![Figure 67. V_{A,B,C} (27P) TC $\angle(3I_0 - I_N)$](image)

As seen from the figure, prior to fault, which occurs around 92ms time, grounding transformer phase currents are very low, and the microgrid voltage is normal. Upon the fault occurrence at F3, the fault current flows through the neutral of the grounding transformer. This current is three times higher than individual phase currents. As seen from the graph, neutral current exceeds the maximum unbalance setting of 2.72A, while phase currents also exceed the grounding transformer normal magnetization value of approximately 0.46A. At this time, REV DIR/REF1R element picks up, because it detects the reverse power flow through the grounding transformer based on the angle difference between $\angle 3I_0$ and $\angle I_N$. At the same time, voltage on phase A goes
down to zero, which causes the 27P element to pick up. After the time delay 27TD of 100ms, which is the time delay chosen to test the functionality of this element, the SEL 787 relay would issue a TRIP command. Note that this time delay would need to be coordinated with time delay from the differential relay on BESS transformer if one exists. There are three observations here that are of major interest:

1. Positive-sequence voltage $V_1$ and negative-sequence voltage $V_2$ slightly change during the fault at F3, and the two elements cannot be used for reliable and secure protection,

2. Zero-sequence voltage element $V_0$ changes significantly during the fault at F3, so this element can potentially also be used for reliable and secure protection,

3. Voltages on phases B and C typically increase during the ground fault and for effectively grounded system, the Coefficient of Grounding (CoG) should not exceed 0.8; as seen from the figure, both phase B and C voltages are well within 1.38p.u. value and also within the temporary overvoltage (ToV) value of 1.2p.u.. If voltages on un-faulted phases during the ground fault exceed 1.2p.u. level for 5 cycles, the relays within the microgrid would trip based on the overvoltage condition.

6.1.4. Ground faults (back-up protection)

In order to perform short-circuit analysis, four separate cases were considered based on the loading within the microgrid and output and availability of PV and BESS. First, in order to get the baseline data, analysis was done on a microgrid that operates normally in islanded mode. Standard [29], section 14.36, which represents manufacturers of motors and drives, states that "operation of the motor above a 5% voltage unbalance condition is not recommended" and provides also a derating curve for operation under voltage unbalance. Section 14.36.5. of the same standard states that a motor operating at normal speed under the voltage unbalance conditions causes current
unbalance in the order of 6-10 times. Taking more stringent requirement of 5% for total feeder voltage unbalance, and assuming that each 1% of voltage unbalance causes 7% of current unbalance, maximum load imbalance is calculated to be ±35%. This value was then taken for calculations of grounding transformer maximum steady-state neutral current. Neutral current ($I_N$) and voltage sequence networks ($V_1$, $V_2$ and $3V_0$) were recorded in Table 28 with steady-state circulating current designated as $I_N$, while Table 29 below shows the baseline values for voltage sequence networks.

**Table 28. Microgrid normal operation with 35% load imbalance**

<table>
<thead>
<tr>
<th>Case</th>
<th>Load</th>
<th>PV</th>
<th>BESS</th>
<th>$I_N$ [A]</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.0 p.u.</td>
<td>1.0 p.u.</td>
<td>VSI-ISO</td>
<td>2.72</td>
</tr>
<tr>
<td>2</td>
<td>1.0 p.u.</td>
<td>OFF</td>
<td>VSI-ISO</td>
<td>2.72</td>
</tr>
<tr>
<td>3</td>
<td>0.3 p.u.</td>
<td>0.2 p.u.</td>
<td>VSI-ISO</td>
<td>0.84</td>
</tr>
<tr>
<td>4</td>
<td>0.3 p.u.</td>
<td>OFF</td>
<td>VSI-ISO</td>
<td>0.84</td>
</tr>
</tbody>
</table>

**Table 29. Baseline - Voltage sequence elements normal operating range**

<table>
<thead>
<tr>
<th>Case</th>
<th>$V_1$</th>
<th>$V_2$</th>
<th>$3V_0$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Min</td>
<td>0.97</td>
<td>0.02</td>
<td>0.01</td>
</tr>
<tr>
<td>Max</td>
<td>1.00</td>
<td>0.04</td>
<td>0.03</td>
</tr>
</tbody>
</table>

Transformer protection is mainly designed to protect the transformer from its internal faults using traditional differential protection (87). In addition, one set of current transformers (CTs) on its secondary side is typically used as a overcurrent (51P) back-up protection for the feeder faults in case of a feeder relay mis-operation or breaker failure. However, this 51P element has a long time-delay ($t_D$). In this paper, new approach for the grounding transformer protection and control scheme is to provide the back-up protection for the microgrid primary and secondary faults when breaker/recloser relays cannot detect the low fault currents and also to possibly detect the internal failure faults at other transformers located within the microgrid. Table 30 shows the relay protective elements, some of which are torque-controlled, that enable this functionality.
Table 30. Grounding transformer protection

<table>
<thead>
<tr>
<th>Protection element</th>
<th>Fault</th>
<th>Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>50N1</td>
<td>LG/LLG</td>
<td>External</td>
</tr>
<tr>
<td>50N3 TC V₁(27P1)</td>
<td>LG/LLG</td>
<td>External</td>
</tr>
<tr>
<td>50N4 TC V₂(59P1)</td>
<td>LG/LLG</td>
<td>External</td>
</tr>
<tr>
<td>50N4 TC 3V₀(59P2)</td>
<td>LG/LLG</td>
<td>External</td>
</tr>
<tr>
<td>V₁₀(27P) TC ((3I₀ - I₉))</td>
<td>Transformer</td>
<td>External</td>
</tr>
</tbody>
</table>

50N represent the Neutral Time-Overcurrent as defined in [42] (in this case, there will be three levels of overcurrent defined: 1, 2 and 4). TC stands for torque-controlled or what is supervising element. 27P1 and 59P1 and 59P2 represent undervoltage and overvoltage protective elements. \(V₁\), \(V₂\) and \(3V₀\) represent the voltage positive-, negative- and zero-sequence networks. Settings for the grounding transformer protection are proposed to be as follows:

1. 50N1 - maximum unbalance current calculated from simulations is 2.72A. Typically, overcurrent settings are set no less than 120% of the maximum current and no more than 0.9 times the minimum fault current. In this case, 50N1 element is the overcurrent element without any torque-control, so the proposed settings is 150% of the maximum unbalance current. Because this element is a back-up protection, for coordination purposes, time delay is typically 200ms slower than the first downstream protection device, which in our case would be B2 breaker of the 4-Way switchgear. However, for the simulation purposes, the time delay has been chosen to be 10 cycles (167ms).

\[50N1P = 150\% \times I_{Nmax} = 150\% \times 2.72A = 4.0A\]
\[50N1D = 0.167s (10 cycles)\]

2. 50N3 TC \(V₁(27P)\) - because this element is torque-controlled by the undervoltage condition of \(V₁\) element, overcurrent setting can be slightly less than 50N1. In this case, proposed setting will be 125% of the maximum unbalance current. Similar argument holds for time delay. Regarding the undervoltage setting (27P1P), it is based on the level below what is considered to be minimum microgrid healthy voltage. Minimum healthy voltage in protection and control
is considered to be any voltage above the 90% of the nominal microgrid voltage of 1.00p.u. or 120V on 120V base voltage level. The proposed setting for undervoltage condition 27P1P is 0.85p.u. or 102V on 120V base voltage level.

\[
50N3P = 125\% I_{Nmax} = 125\% \times 2.72A = 3.4A \\
50N3D = 0.167s (10 cycles) \\
27P1P = 102V (0.85p.u.) \\
27P1D = 0.167s (10 cycles)
\]

3. 50N4 TC V₂(59P1) - because this element is torque-controlled by the overvoltage condition of V₂ element, overcurrent setting can be slightly less than 50N1. In this case, proposed setting will be 125% of the maximum unbalance current. Similar argument holds for time delay. Regarding the overvoltage setting (59P1P), it is based on the notion that during the normal operating conditions, negative-sequence voltage does not exceed 10% of the nominal voltage level. The proposed setting for overvoltage condition 59P1P is 0.15p.u. or 18V on 120V base voltage level.

\[
50N4P = 125\% I_{Nmax} = 125\% \times 2.72A = 3.4A \\
50N4D = 0.167s (10 cycles) \\
59P1P = 18V (0.15p.u.) \\
59P1D = 0.167s (10 cycles)
\]

4. 50N4 TC 3V₀(59P2) - in this case, overcurrent level is the same, but regarding the overvoltage setting (59P2P), it is based on the notion that during the normal operating conditions, value for zero-sequence voltage also does not exceed 10% of the nominal voltage level. Since relays typically use 3V₀ measurement, the proposed setting for overvoltage condition 59P2P is 0.40p.u. or 48V on 120V base voltage level.

\[
50N4P = 125\% I_{Nmax} = 125\% \times 2.72A = 3.4A \\
50N4D = 0.167s (10 cycles) \\
59P2P = 48V (0.40p.u.) \\
59P2D = 0.167s (10 cycles)
\]
Figure 68 shows how the neutral current in the grounding transformer changes as a function of the operating mode (grid connected, transition to island, islanded mode, LG fault and microgrid blackout) within the microgrid. As seen from the graph, once the LG fault occurs, both overcurrent elements assert, because the neutral current far exceeds the 3.4A and 4.0A set-points. The protection operates within 10 cycles for both cases. Note that in the actual relay implementation, there is a typical delay of up to 2 cycles, due to the signal processing time.

![Figure 68. Neutral current $I_N$.](image)

Figure 69 shows the voltage sequence networks during the same time.

![Figure 69. Voltage sequence networks.](image)
As seen from the graph, LG fault can be detected by the positive and negative-sequence voltage elements, which in this case are used for torque-control. Note that the neutral current in the grounding transformer only flows during LG and LLG faults (which make up approximately 90-95% of all faults), while it can no detect line-to-line (LL) and 3Φ (LLL/LLLG) faults, as seen from the graph on the Figure 70 below. The reason for this is that the LL fault has only positive- and negative-sequence network, while 3Φ fault has only positive-sequence network.

Figure 70. Neutral current $I_N$ during LL and 3Φ faults.

6.1.5. Internal winding-to-tank/ground faults on secondary ($\Delta$) side

For the purposes of simulation, winding-to-tank/ground fault was placed at location F2 ($\Delta$ side of grounding transformer) between phases A and ground and voltages were recorded using per unit analysis. Figure 71 shows the change in voltage sequence networks (top), phase-to-ground voltages (middle), and TRIP signal. Based on the analysis, using overvoltage element (59P) with setting of 0.40p.u for zero-sequence voltage ($3V_0$) and time delay (59TD) of 100ms in this case, torque-controlled by the phase voltage (in this case $V_A$) undervoltage element (27P) set at 0.85p.u., it is possible to detect the winding-to-ground/tank faults. In order to implement this protection scheme on the grounding transformer $\Delta$ side, it is necessary to install $\Delta$-Yg transformer, which is a sensing transformer rated at 100VA with voltage levels of 480V – 120V and accuracy of 0.5%
or better. This must be done because there is no way to measure the desired relay settings in an ungrounded system (like $\Delta$).

![Figure 71. $3V_0(59P)$ TC $V_{PH}(27P)$.](image)

6.1.6. Internal winding-to-winding faults on secondary ($\Delta$) side

For the purposes of simulation, winding-to-winding fault was placed at location F2 ($\Delta$ side of grounding transformer) between phases A and B and voltages were recorded using per unit analysis. Figure 72 shows the change in phase-to-phase voltages (top), voltage sequence networks (middle), and TRIP signal.

![Figure 72. $V_{PP}(27PP)$ and $V_2(59P)$.](image)
Based on the analysis, using undervoltage element (27PP1) with setting of 0.85p.u. and time delay (27TD) of 100ms in this case, it is possible to detect the winding-to-winding faults. Based on the analysis, the same could be achieved using the overvoltage setting (59P1P) of 0.15p.u. and the same time delay of 100ms.

6.1.7. Internal faults detected by mechanical devices

In order to provide the protection from the internal faults, additional sensors such as sudden pressure relay, vacuum/pressure sensors, low oil sensor, winding/oil temperature must be installed on this transformer and their outputs must be integrated within the relay. However, this represents only part of the solution for the grounding transformer protection scheme for the internal faults. Detection of grounding transformer internal faults during the operation of microgrid in islanded mode with inverter-based DER is not reliable and secure using the traditional methods due to the low fault current levels. Any internal fault within the transformer can be detected by the presence of gases.

<table>
<thead>
<tr>
<th>Protection element</th>
<th>Fault</th>
<th>Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>26Q (Alarm)</td>
<td>Oil temperature</td>
<td>Internal</td>
</tr>
<tr>
<td>26Q (Trip)</td>
<td>Oil temperature</td>
<td>Internal</td>
</tr>
<tr>
<td>49W (Alarm)</td>
<td>Winding temperature</td>
<td>Internal</td>
</tr>
<tr>
<td>49W (Trip)</td>
<td>Winding temperature</td>
<td>Internal</td>
</tr>
<tr>
<td>71Q (Alarm)</td>
<td>Low oil level</td>
<td>Internal</td>
</tr>
<tr>
<td>71Q (Trip)</td>
<td>Low oil level</td>
<td>Internal</td>
</tr>
<tr>
<td>63V</td>
<td>Vacuum</td>
<td>Internal</td>
</tr>
<tr>
<td>63P</td>
<td>Pressure</td>
<td>Internal</td>
</tr>
<tr>
<td>63SPR</td>
<td>Sudden pressure</td>
<td>Internal</td>
</tr>
<tr>
<td>DGA</td>
<td>Dissolved gas analysis</td>
<td>Internal</td>
</tr>
</tbody>
</table>

For that reason, dissolved gas analysis (DGA) system should be added to the grounding transformer and the trip output would need to include the faults detected by the DGA system. This is the new approach that is typically not used in transformer protection, because it is not entirely known how long does it take for the gases to show up on DGA analysis after the fault occurrence,
and it the transformer might be severely damaged already by the time the DGA analysis detects these gases. Table 31 shows the new design of the grounding transformer protection and control which includes mechanical sensors and DGA. This protection is typical for large substation transformers (> 15MVA) and typically is never used in transformers with lower rating. However, due to the fact that many of the DER transformers have significantly lower lifetime compared to the traditionally implemented transformers, this protection is a must. Note also that DGA analysis (used typically on transmission transformers) implementation can easily cost more than a transformer itself at lower MVA levels.

6.2. Grounding Transformer Protection Scheme – Field Testing

Some of the protection and control elements proposed in this section regarding the new grounding transformer protection and control methodology have been tested within the electric utility’s microgrid. Section of the microgrid, shown in Figure 73, was islanded, and load bank with 30kW of load was connected as the main load. The microgrid also had additional auxiliary load and 10kVA HVAC. LG fault was placed on the secondary side of 1000kVA transformer (12.47kV – 277V/480V) and this is also shown on the section of the microgrid below.

Figure 73. Microgrid - LG fault.
Figure 74 shows the fault current as measured by the neutral CT of the grounding transformer. This neutral current is equal to 1/3 of each of the grounding transformer phase currents for any ground fault outside of this transformer.

As expected, the fault current was significantly above the 50N1P set-point of 4.0A and the microgrid tripped within 2 cycles as expected.

In addition, the fault current was also above both 50N3P and 50N4P set-points of 3.4A but these set-points are torque-controlled by the voltage sequence networks. Figure 75 shows the grounding transformer neutral current and positive, negative- and zero-sequence voltage elements during LG fault. As seen from the graph, only positive-sequence voltage element \( V_1 \) can be used for reliable and secure torque control because it reached 0.40p.u. level, which is enough margin below its undervoltage set-point of 27P1P = 0.85 p.u. Negative-sequence voltage element \( V_2 \) oscillates slightly above and below its overvoltage set-point of 59P1P = 0.40 p.u., while zero-sequence voltage element \( 3V_0 \) never reaches the set-point 59P1P = 0.40 p.u. One observation can be made
that after the relays within the microgrid have tripped all high voltage breakers, there was still voltage present within the microgrid.

![Figure 75. Voltage sequence networks during LG fault.](image)

The reason for this phenomenon is the fact that the BESS inverter has undervoltage setting (27) with time delay of 10 cycles or 160ms (which follows the [43] standard). During this time, the inverter is still trying to support the voltage at its output, as part of the voltage ride-through scheme. This protection scheme could be further improved to enable sending the command to the BESS inverter PLC and PCS to stop the IGBT switching for the feeder fault.

Finally, Figure 76 shows all TRIP signals and their timing issued during this fault. First graph shows the 50N1P element fault detection and TRIP times. Note that there is internal relay delay with digital signal processing, so the relay element does not pick up immediately after the neutral current exceeds the set-point. Vertical magenta line shows the fault occurrence and vertical black line shows the fault clearing time (TRIP) caused by the 50N1T element (50N1T element is derived from 50N1P element + delay time). Last graph shows that only $I_N$ TC by $V_1$ (red line) can be used for secure and reliable fault detection.
Since, the LG fault was placed within the microgrid, second proposed protection scheme can be verified here – ground faults back-up protection. The protection is based on the positive-sequence undervoltage element (27P1P) being torque controlled by the difference of phase angles between $I_N$ and $3I_0$.

![TRIP signals during the LG fault](image1)

**Figure 76.** TRIP signals during the LG fault.

Figure 77 shows the positive sequence voltage ($V_1$) and phase angle difference for $\angle(I_N, 3I_0)$ before, during and after the LG fault within the microgrid (which occurs at approximately 92ms).

![Positive-sequence voltage ($V_1$) and phase angle difference](image2)

**Figure 77.** Positive-sequence voltage ($V_1$) and phase angle difference for $\angle(I_N, 3I_0)$. 
As seen from the graph, at moment $V_1$ drops below the 27P1P setting of 0.85p.u. and phase angle difference becomes greater than 90° or less than -90°, the relay has detected the ground fault somewhere within the microgrid.

In addition, two overcurrent elements are also added as additional security elements in order to ensure that the scheme does not have nuisance trips. Figure 78 shows the grounding transformer phase and neutral currents, that also must exceed pre-determined set-points of 1.25A (phase) and 4.0A (neutral).

![Figure 78. Grounding transformer phase and neutral currents.](image)

Both set-points were derived based on the simulations. Regarding the grounding transformer phase current setting, without simulations, the maximum magnetizing current for a transformer is in 2-5% range, so this also could have been used as a starting point for the setting. Taking this protection into account, the following Figure 79 shows the times associated with each of the four elements exceeding their set-points and TRIP command. As seen from the graph, when all four conditions are met – positive-sequence voltage undervoltage, angle difference, neutral overcurrent and phase overcurrent conditions, the relay issues TRIP command. Since this is a back-up protection, this
device should have 200ms time delay compared to the first upstream protective device, which in this case is the protection on breaker B3.

![Graph](image)

Figure 79. Grounding transformer back-up protection – digital signals.

### 6.3. Conclusion

Design and implementation of secure and reliable protection and control scheme for the grounding transformer within the microgrid with inverter-based DERs presents very complex engineering endeavor due to the low fault currents. This section introduces the new approach to the microgrid grounding transformer protection and control that uses the grounding transformer as a back-up protection for the feeder faults as well as the protection for the grounding transformer internal faults. The main conclusion is that the new proposed approach provides higher security and reliability compared to the traditional protection implemented at the grounding transformer. However, more research is needed to verify that the implementation of this new approach is effective for the internal faults, as the current available field data regarding the microgrid grounding transformer internal failures is not publicly available.
CHAPTER 7: Microgrid Protection and Control

7.1. Background

Most of the current approaches to the microgrid protection and control schemes could be divided into four main approaches: differential protection, communications-based protection, adaptive protection and overcurrent protection. Differential protection has numerous benefits over other types of protection, and it has been heavily researched. In [44], authors proposed the use of differential protection based on the variable tripping time. Besides the huge cost of this solution that makes it impractical, the second shortcoming is that the solution might not work reliably and safely if the microgrid is located on sub-transmission feeder due to the inability to discriminate between the low fault currents vs. high load currents at the end of the feeder. In [45], authors introduced the differential protection scheme that can detect the faults along the feeder, but it requires the installation of additional relays along the feeder with communication devices. Authors in [46] introduced the differential protection based on the positive sequence fault component using either peer-to-peer or WLAN networks. Authors in [47] proposed the single and dual protection strategy using differential scheme with overcurrent and voltage directional supervision. Authors in [48] introduced the dual protection scheme where differential protection is used as a primary protection and in cases of the loss of communications, the protection reverts back to the overcurrent protection. In [49] authors proposed the differential primary protection being back-up by the voltage, frequency and overcurrent protection elements, while in [50] authors proposed the communications scheme using directional overcurrent relays dual settings. Authors in [51] introduced the new approach using agent-based distributed communication that utilizes the overcurrent and frequency selectivity method. Authors in [52] have also introduced communication-based protection scheme that utilizes the directional overcurrent relays equipped
with inter-tripping and blocking functions. However, the scheme was only tested on a microgrid with synchronous-based DGs. Authors in [53] proposed hybrid communications and datamining based approach (using distributed statistical classifier based on the random forest algorithm) in order to identify the relay settings and parameters. In general, communications based microgrid protection and control approach is rarely, if ever, implemented in actual microgrids, due to the high capital construction cost.

Adaptive protection has gained significant traction in recent years. Authors in [54] proposed the adaptive protection scheme for device coordination on the feeders with high penetration of DERs, but the authors state that the scheme might not work with few DERs. Authors in [55] proposed the adaptive protection based on the positive- and negative-sequence superimposed currents as a function of the microgrid operation mode. However, this scheme was tested on a microgrid with synchronous generator, so its effectiveness is unknown for the microgrid with inverter-based DERs. Authors in [56] proposed the use of local voltage measurements with some adaptive form of protection. Authors in [57] have proposed the dynamic Thevenin equivalent circuit and adaptive change of the relay primary and back-up overcurrent settings as a function of this equivalent circuit. Simulations were done on a microgrid that includes synchronous generator as one of DERs. Authors in [58] and [59] proposed the dynamic calculation of the overcurrent settings as a function of the operating mode of DERs and microgrid status (islanded or grid-connected).

Overcurrent protection, which is traditional way of protection of the distribution feeders has been found to be noneffective if implemented within the microgrid with inverter based DERs. Authors in [60] provided a method that uses the fault current coefficient and time delay assignment for microgrid protection system with central protection unit. Authors in [61] introduced the new
concept where the fault is detected by measuring indirectly the microgrid impedance and DERs directly inject a current proportional to the measured microgrid impedance cause the DER that is the closest to the fault to trip first. Authors in [62] proposed the new directional element based on the magnitude and angle of the negative-sequence impedance. The following Figure 80 shows the new design approach for implementation of the microgrid with inverter-based DERs on a distribution feeder along with all new protection and control elements that will be presented in the next few chapters.

![Figure 80. Microgrid protection and control scheme – new approach.](image)

**7.2. Overcurrent protection**

Traditional generation system consists of synchronous generators. These generators are designed to provide the same 60Hz signal fault response, regardless of vendor, if they have the same MVA rating and the same impedance. Unfortunately, the same cannot be said for the response by the inverter-based DERs. The differences between different vendors are such that it is extremely challenging to design the protection and control scheme that is based on traditional
overcurrent elements. First, synchronous generators can provide fault currents in the range of 8 – 12 p.u., while inverter-based DERs can provide fault current in 1.2 – 2.4 p.u. range. Second, synchronous generators provide all three-sequence networks for both voltage and current, while some inverter-based DERs provide only positive-sequence networks, some provide both positive- and negative-sequence networks (they typically do not provide zero-sequence networks). In addition, some inverter-based DERs intentionally suppress the voltages during the faults. Due to the aforementioned reasons, overcurrent protection cannot be reliably used for reliable and secure microgrid protection and control.

Figure 81 below shows the basic one-line diagram for the microgrid that will be used for simulation and fault analysis.

![Microgrid one-line diagram with LG fault on 480V side](image)

Figure 81. Microgrid one-line diagram with LG fault on 480V side.

4-Way switchgear consists of four breakers connected to the common bus. Breaker B1 is used as a point of common coupling (PCC) and this is the breaker used for islanding and grid re-synchronization. Breaker B2 is connected to grounding transformer ($Y_g - \Delta$), which has several different purposes. In this case, neutral current transformer (50:1 ratio) has been implemented between the neutral and ground of the $Y_g$ side of this transformer, along with line-to-ground
voltage measurements (60:1 ratio) from each of the three individual phases (making the base voltage of 120V).

These analog measurements were implemented as part of the relay that has been integrated with grounding transformer. Breaker B3 is connected to the feeder, which has residential, commercial and industrial load. Total transformer connected capacity is 300kVA, with maximum load of 100kVA. These loads were aggregated for the simplicity, and 100kVA photovoltaic (PV) system was also implemented as part of the inverter-based DER generation group and connected to 12.47kV feeder through breaker B5. Breaker B4 is connected to 150kVA battery energy storage system (BESS). System protection relay has been implemented within 4-way switchgear and this relay has four sets of CTs (one for each breaker), and two sets of PTs (both grid and microgrid side of breaker B1). In addition, as part of the new approach, both BESS and PV also have relays implemented with phase voltage and current inputs as part of the overall protection scheme between the AC input and low side of the corresponding DER transformer. For the purposes of protection and control analysis, LG fault was simulated on the secondary side of 12.47kV - 277V/480V transformer.

First, baseline values for the normal operation of the microgrid have been simulated based on the maximum 35% load imbalance (this value was calculated based on the analysis of data provided by [29] and [63] standards). Table 32 below shows the four baseline cases for BESS, PV and feeder loads that cover the limits of daily operations (minimum and maximum).

<table>
<thead>
<tr>
<th>Case</th>
<th>Load</th>
<th>PV</th>
<th>BESS</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.0 p.u.</td>
<td>1.0 p.u.</td>
<td>VSI-ISO</td>
</tr>
<tr>
<td>2</td>
<td>1.0 p.u.</td>
<td>OFF</td>
<td>VSI-ISO</td>
</tr>
<tr>
<td>3</td>
<td>0.3 p.u.</td>
<td>0.2 p.u.</td>
<td>VSI-ISO</td>
</tr>
<tr>
<td>4</td>
<td>0.3 p.u.</td>
<td>OFF</td>
<td>VSI-ISO</td>
</tr>
</tbody>
</table>

The recorded baseline values are shown in the Table 33, Table 34, Table 35 and Table 36.
Based on the simulations for the four cases above, baseline values for neutral current and primary voltage sequence networks (1-positive, 2-negative, 0-zero) were recorded and shown in Table 37 below:

Table 37. Neutral current and voltage sequence network values - baseline

<table>
<thead>
<tr>
<th>Measurement</th>
<th>Min</th>
<th>Max</th>
</tr>
</thead>
<tbody>
<tr>
<td>$I_n$ [A]</td>
<td>0.84</td>
<td>2.72</td>
</tr>
<tr>
<td>$V_1$ [p.u.]</td>
<td>0.97</td>
<td>0.98</td>
</tr>
<tr>
<td>$V_2$ [p.u.]</td>
<td>0.02</td>
<td>0.04</td>
</tr>
<tr>
<td>$3V_0$ [p.u.]</td>
<td>0.03</td>
<td>0.06</td>
</tr>
</tbody>
</table>
The following two figures (Figure 82 and Figure 83) show the results of the baseline analysis. Within the two figures, both minimum and maximum values of different voltage and current sequence networks have been summarized for further analysis.

Figure 82. Voltage sequence network for PCC, BESS and PV relays.

Figure 83. Current sequence network for PCC, BESS and PV relays.

In order to investigate if traditional overcurrent protection can be reliably and securely implemented within the microgrid, LG fault was placed within the microgrid and all 4 cases as shown in Table 32 were simulated again and results were recorded at the same locations as before. Figure 84 shows the timing sequence for the simulation that was carried out. The microgrid is originally connected to the grid, and BESSS and PV are running. At \( t=2 \) seconds, the microgrid goes to islanding mode, and at \( t=3.25 \) seconds, LG fault occurs within the microgrid. The fault is cleared by the protective devices at 3.5 seconds.
Figure 84. Current sequence network for PCC, BESS and PV relays.

Figure 85 shows the real power (P) and reactive power (Q) output of the BESS, PV and the total microgrid load during grid-connected mode, transition to island, islanded mode, LG fault and after the fault has been cleared. LG fault was placed within the microgrid on the high voltage side (12.47kV), and voltages as currents were recorded at several locations within the microgrid. Figure 86 shows the magnitude and the duration of this LG fault.

Figure 85. Microgrid real and reactive powers.

As can be seen from the graph, total fault current is close to 17A during the sub-transient portion of response, which amounts to 367.17kVA of LG fault. Knowing that the PV is operating at 100kVA output and that the maximum output of the BESS is 150kVA, this results in total fault current contribution of 1.47 p.u.
Figure 86. LG fault (phase A) on 12.47kV bus.

Figure 87 shows the changes in BESS phase currents during LG fault simulations for one of the cases. Traditional overcurrent relay settings are set at 1.5p.u. or 2.0p.u. above the maximum load current. In addition, relay operates based on the curve, which most of the time is the inverse curve (U3) and user-defined time-dial.

Figure 87. BESS – phase currents during LG fault.

Even though BESS phase currents show the current increase in all three phases, this increase is very small comparable to the rated output of the DERs and only phase A reaches over 2.0p.u. for a really short period of sub-transient response. Following, the fault current falls to slightly above the 1.0p.u. BESS rating. As seen from the graph, overcurrent (50/51) elements cannot be used for secure and reliable protection. Figure 93 show the changes in PV phase currents during LG fault.
simulations for one of the cases, and the maximum fault phase current reaches 1.13 per unit before it goes down to zero.

Figure 88. PV – phase currents during LG fault.

LG fault was simulated for all 4 cases, and results were aggregated in order to compare the currents measured during the normal operating mode and during the LG fault. Figure 89 shows the results of the simulations.

Figure 89. Fault currents seen by BESS and PV during LG faults.

As seen from the analysis, normal operating current range and fault current range overlap for both BESS and PV. For that reason, traditional overcurrent analysis cannot be used for the reliable and secure microgrid protection and control.
7.3. Overcurrent protection with torque-controlled voltage sequence network elements

In this section, new approach for the protection and control of microgrids with inverter-based DERs is proposed that is based on the negative- and zero-sequence overcurrent elements torque-controlled by the voltage sequence networks. In order to understand this method, it is necessary to understand two aspects of protection and control engineering – symmetrical components and how each of those components is connected as a function of the type of the fault. Symmetrical components method simplifies the analysis of three-phase power system by creating a mathematical representation of the unbalanced system as a linear combination of balanced sets using transformation.

Symmetrical components method in general has been introduced in 1918 by Charles Legeyt Fortecue, who proved that any set of unbalanced N vectors can be expressed as the sum of N symmetrical vectors, if N is a prime number. This concept was implemented on a set of 3 phasors in 1948 by Edith Clarke. Three-phase unbalanced system can be represented as the sum of positive-sequence component, which has the same phase rotation (ABC) as the system under the analysis where the vectors are shifted exactly 120°, negative-sequence component, which has reverse phase rotation (ACB) as the system under the analysis where the vectors are also shifted exactly 120° and zero-sequence component, where the vectors are in phase with each other. Figure 90 [64] shows the conversion between the phase and symmetrical domain.

![Figure 90. Symmetrical components.](image-url)
The conversion between the unbalanced and balanced system can be represented using the following set of equations:

\[
V_A = V_1 + V_2 + V_0 \\
V_B = \alpha^2 V_1 + \alpha V_2 + V_0 \\
V_C = \alpha V_1 + \alpha^2 V_2 + V_0
\]

where \( \alpha = 1 \angle 120^0 \). From here, the unbalanced system can be represented as the sum of positive-, negative- and zero-sequence networks [64]:

![Symmetrical components of an unbalanced system](image)

Figure 91. Symmetrical components of an unbalanced system.

After the sequence networks have been defined, the next step is the understanding of how they are connected as a function of the fault type. If the fault impedance between the phase and the common point (neutral) is defined as \( Z_F \) and impedance from the neutral to the ground is defined as \( Z_G \), then the following Figure 92 shows the way that the sequence networks are connected as a function of the fault type on the feeder.

![Sequence networks as a function of the fault type](image)

Figure 92. Sequence networks as a function of the fault type.
This is important to understand, because each fault has different sequence components, so protection and control scheme based on sequence components has to be tied to the Figure 92 equivalent circuits. As seen from the graph, ground fault currents have all three components (positive-, negative- and zero-), LL faults have positive- and negative-sequence components, while 3Φ faults have positive-sequence component only. Using the same simulations as in previous section, sequence networks for both currents and voltages for BESS and PV were calculated and Figure 93 show the results of the symmetrical component analysis for currents.

![Figure 93. BESS and PV – current sequence networks during LG fault.](image)

Traditionally, positive-sequence currents are very close to the actual phase currents because they have the same orientation (ABC). Negative- and zero-sequence currents, under the maximum unbalanced operating conditions do not exceed 10% of the positive-sequence currents. This is important to know, because the field settings are based on understanding of these protection and control elements. Based on the current sequence elements as seen by the BESS and PV, the following is the set of conclusions that can be made:

1. In today’s field implementations, AC side of DER inverters is typically equipped with breaker that has no relay associated with it, and its main protection is based on LSI settings (L-long,
S-short and I-instantaneous). These breakers cannot operate based on the sequence networks.

For that reason, a new protection and control scheme has been proposed for both BESS and PV DERs which includes installation of the differential and overcurrent relay as shown on the Figure 94.

![Figure 94. BESS & PV – new protection and control scheme.](image)

In this case, SEL 487E relay has been added in order to protect the BESS GSU transformer (differential protection using 87P and 87Q relay elements), and to potentially detect the downstream faults using the current and voltage sequence networks using two sets of CTs and one set of PTs. The TRIP/CLOSE output of this relay is wired into the TRIP/CLOSE circuits.
of the AC breaker. This scheme now enables the complete protection that now also includes the short ungrounded section of 300-800V\textsubscript{AC} cable between the DER inverter and BESS GSU,

2. Positive-sequence currents \( I_1 \) for both BESS and PV cannot be used for reliable and secure protection and control because their maximum fault current values during the fault are slightly above the nominal kVA rating,

3. Negative-sequence current \( I_2 \) reaches 0.35p.u. for BESS and 0.22p.u. for PV. Since these two values are higher than the maximum level for negative-sequence current of 0.10p.u. they are good candidates for the protection and control scheme, provided that the voltage-sequence networks provide secure and reliable torque-control element. Figure 95 shows the range of BESS negative-sequence currents for all 4 cases. The set-point for \( I_2 \) for BESS can be calculated as (within the relay, this element is designated with 51Q settings):

\[
I_{2\,\text{MAX}} = (1.1\times I_2 @ I_{\text{LOAD\,MAX}})*110\% = (1.1\times 0.04\text{p.u.})*110\% = 0.0484 \text{ p.u.}
\]

\[
I_{2\,\text{PU}} = 1.5\times I_{2\,\text{MAX}} = 1.5\times 0.0484\text{p.u.} = 0.0726 \text{ p.u.}
\]

In order to check for the security of this scheme, we see that the set-point is significantly lower than the minimum level of negative-sequence current during the grounding fault of 0.36p.u. Based on this assessment, even though it seems that this element can be used by itself for protection and control, in order to increase the security and reliability of this
scheme, this setting will be used in protection and control scheme along with torque-controlled element. The curve chosen is an inverse curve (U3) with time dial of 0.5. Figure 96 shows the range of PV negative-sequence currents for all 4 cases.

The curve chosen is an inverse curve (U3) with time dial of 0.5. Figure 96 shows the range of PV negative-sequence currents for all 4 cases.

![Figure 96. PV I2 current – baseline vs. LG fault.](image)

The set-point for $I_2$ for PV can be calculated as:

$$I_{2\text{MAX}} = (1.1 \times I_2 @ I_{LOAD\text{MAX}}) \times 110\% = (1.1 \times 0.08\text{p.u.}) \times 110\% = 0.968\text{p.u.}$$

$$I_{2\text{PU}} = 1.5 \times I_{2\text{MAX}} = 1.5 \times 0.968\text{p.u.} = 0.145\text{p.u.}$$

This set-point is 150% lower than the minimum negative-sequence current during the fault. As such, this element should not be used on its own as part of the protection and control scheme for microgrid. In order to increase reliability and security of this scheme, using $I_2$ being torque-controlled by the $V_2$ provides better overall protection design. Similar to before, this scheme would also have to be then torque-controlled by the status of CSD device (all phases closed).

4. Zero-sequence currents $3I_0$ as seen by the BESS and PV are zero, so this sequence element cannot be used in the overall scheme. This is expected, because the AC inverter side of both BESS and PV are ungrounded (transformer is connected to floating Y side of the BESS GSU); Zero-sequence current component is seen by the breaker B3 and recloser R1, because grounding transformer connected to 12.47kV feeder through breaker B2 provides the zero-
sequence path for the fault current. Figure 97 shows the sequence networks associated with breaker B3.

![Sequence networks for breaker B3](image)

Figure 97. Breaker B3 sequence networks.

Under the normal operating conditions, breaker B3 sees the zero-sequence current less than 0.06 p.u. During the fault conditions, this current reaches the range of 0.53 – 0.63 p.u., so this element can be used as a protection and control element at breaker B3 (similar holds for recloser R1 for the faults downstream from it). However, in order to increase the security and reliability of this protection and control scheme, this element would also have to be torque-controlled by a voltage sequence element. However, note that breaker B3 will have two new proposed protection elements presented in successive chapters, that have much higher reliability and security. The set-point for 3I₀ for BESS can be calculated as (within the relay, this element is designated with 51Q settings):

\[ 3I₀_{PU} = 1.5*3I₀_{MAX} = 1.5*0.18 \text{p.u.} = 0.27 \text{ p.u.} \]

Figure 98 shows the sequence networks for 12.47kV voltage measured at BESS and PV. What can be seen from this figure, after the fault, positive-sequence voltage \( (V₁) \) experiences the voltage sag from 1.0 p.u. to 0.47 p.u., while negative-sequence voltage \( (V₂) \) changes from 0.037 p.u.
to 0.63 p.u. (note that the maximum $V_2$ value with all of the system imbalances on any feeder never exceeds 0.10 p.u.).

Similarly, zero-sequence voltage also changes, but very slightly. Typically, all faults should be clear as fast as possible in order to prevent the equipment damage, so the protection and control design must be improved. Note that this simulation does not include breaker trip time, which is another 6 – 8 cycles, and time delay associated with analog signal processing time which, based on the field results, can be as high as 500ms, bringing total trip time to maximum of 831ms (for example, for 81U set-point of 59.3Hz, the relay has a delay of recording and processing this data, so by the time it trips, the actual frequency reaches 58.7Hz). Knowing that fast tripping time of substation breaker is total of 15 cycles or 240ms, there is obvious need to improve the trip time.

Based on the voltage sequence elements as seen by the BESS and PV, the following is the set of conclusions that can be made:

1. Positive-sequence voltage $V_1$ – based on the fault current analysis, positive-sequence voltage $V_1$ drops from 1.00 p.u. during the baseline conditions to the range of 0.47 – 0.59 p.u., which is significant change. The minimum setting for normal voltage on the power system is typically $V_1 = 0.90$ p.u., which in this case is much higher than the maximum value of $V_1$ during the LG fault (Figure 99). Using undervoltage setting (27P1P) of 0.85 p.u. with time delay of 120 cycles
as a torque-control element along with negative-sequence overcurrent element at BESS and PV can result in secure and reliable protection and control scheme,

![Figure 99. 12.47kV $V_1$ voltage – baseline vs. LG fault.](image)

2. Negative-sequence voltage $V_2$ – Based on the fault analysis, the $V_2$ increases from 0.02 p.u. during the baseline conditions to the range of 0.6 – 0.7 p.u., which is significant change as seen on Figure 100. The maximum expected value for negative-sequence voltage on the power system is typically $V_2 = 0.10$ p.u., which in this case is much lower than the maximum value of $V_2$ during the LG fault (Figure 100). Using overvoltage setting (59P1P) of 0.20 p.u. with time delay of 120 cycles as a torque-control element along with negative-sequence overcurrent element at BESS and PV can result in secure and reliable protection and control scheme.

![Figure 100. 12.47kV $V_2$ voltage – baseline vs. LG fault.](image)
3. Zero-sequence voltage \((3V_0)\) – this element reaches the maximum value of 0.15p.u., so it cannot be used as a torque-control element.

Table 38 summarizes the analysis above along with the proposed settings for current sequence network and the corresponding voltage sequence torque-control elements. Note that settings for negative-sequence current elements are the same for both BESS and B3, because these two devices are very close, so it is not possible to coordinate between the two. The main difference between the BESS and B3, as noted before is that B3 has a zero-sequence component. Also, in this case, the fault was placed between the breaker B3 and recloser R1.

Table 38. System protection and control elements for LG fault detection in islanded mode

<table>
<thead>
<tr>
<th>Protection Element</th>
<th>Relay location</th>
<th>Set point</th>
<th>Curve</th>
<th>Time dial</th>
<th>Torque-control element</th>
</tr>
</thead>
<tbody>
<tr>
<td>(I_2) TC V₁</td>
<td>B2/B3</td>
<td>0.073 p.u.</td>
<td>U3</td>
<td>0.5</td>
<td>27P₁P=0.85p.u. 27P₁TD=120cyc</td>
</tr>
<tr>
<td></td>
<td>B5</td>
<td>0.145 p.u.</td>
<td>U3</td>
<td>0.5</td>
<td>27P₁P=0.85p.u. 27P₁TD=120cyc</td>
</tr>
<tr>
<td>(I_2) TC V₂</td>
<td>B2/B3</td>
<td>0.073 p.u.</td>
<td>U3</td>
<td>0.5</td>
<td>59P₁P=0.20p.u. 59P₁TD=120cyc</td>
</tr>
<tr>
<td></td>
<td>B5</td>
<td>0.145 p.u.</td>
<td>U3</td>
<td>0.5</td>
<td>59P₁P=0.20p.u. 59P₁TD=120cyc</td>
</tr>
<tr>
<td>(3I_0) TC V₁</td>
<td>B3</td>
<td>0.270 p.u.</td>
<td>U3</td>
<td>0.5</td>
<td>27P₁P=0.85p.u. 27P₁TD=120cyc</td>
</tr>
<tr>
<td></td>
<td>R1</td>
<td>0.200p.u.</td>
<td>U3</td>
<td>0.5</td>
<td>27P₁P=0.85p.u. 27P₁TD=120cyc</td>
</tr>
<tr>
<td>(3I_0) TC V₂</td>
<td>B3</td>
<td>0.270 p.u.</td>
<td>U3</td>
<td>0.5</td>
<td>59P₁P=0.20p.u. 59P₁TD=120cyc</td>
</tr>
<tr>
<td></td>
<td>R1</td>
<td>0.200p.u.</td>
<td>U3</td>
<td>0.5</td>
<td>59P₁P=0.20p.u. 59P₁TD=120cyc</td>
</tr>
</tbody>
</table>

For that reason, recloser R1 will not see the upstream fault. Note that the coordination time between the recloser R1 and breaker B3 is 200ms. Even though this approach provides more reliable and secure microgrid protection compared to the traditional approach, it still requires settings based on the load current.

7.4. Protection scheme for the faults on secondary side \((277/480V)\)

In addition to having line to ground faults on 12.47kV side of the system, these faults can also occur on the customer side. Typically, industrial and commercial customers have 277V/480V
power supply. These customers are typically served by three phase 12.47kV – 277V/480V transformers which have internal bayonet fuses. The objective of this part of the analysis is to determine if the transformer high-side bayonet fuses can clear the secondary faults or if the breaker/reclose relays and/or DER protection can detect and clear these faults. The main concern in this case is that the faults on the secondary side might not clear because of the lack of inertia-based generation within the microgrid and that due to the low fault current levels, fuses might fail to operate, especially if the customer load is far away from the generation. In order to test this use case, LG fault was simulated as close as possible to the BESS. The load in this case was set to 100kVA with some imbalance percentage. Table 39 below shows the 480V load characteristics in the baseline case.

Table 39. 480V Load characteristics

<table>
<thead>
<tr>
<th>Phase</th>
<th>Load [kW]</th>
<th>I\text{A}, I\text{B}, I\text{C} [A]</th>
<th>I\text{A}, I\text{B}, I\text{C} [A] XMFR high side</th>
<th>I\text{I}, I\text{I}, I\text{I} [A] XMFR high side</th>
<th>I\text{I}, I\text{I}, I\text{I} [A] XMFR high side</th>
<th>V\text{1}, V\text{2}, V\text{0} [p.u.] XMFR high side</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>26.7</td>
<td>96.44 3.73 118.1 4.55 1.00</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>B</td>
<td>33.3</td>
<td>120.3 4.63 13.47 0.52 0</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C</td>
<td>40.00</td>
<td>144.5 5.56 13.42 0.52 0</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The load on this customer is 100kVA, so the transformer that this customer is fed by would have to be 150kVA (typical standard transformer ratings for 12.47kV Yg – 277V/480V Yg transformers are 75kVA, 150kVA, 225kVA, etc…). Typically, 150kVA transformer has a bayonet fuse on the high side of 15A in order to account for high inrush currents. LG fault (phase A) was placed on the secondary of this transformer, and voltage and current measurements were taken along the microgrid. Figure 101 shows the fault current as simulated on the secondary side of the 150kVA transformer.

The fault current reaches approximately 310A before the protection relay (which in this case was based on the neutral overcurrent element within the grounding transformer) causes the whole microgrid to black-out. 310A of secondary fault current is equivalent to 11.93A of the
primary current. Since the fuse on the high side of the transformer is rated at 15A, it is obvious that this fuse will not clear the fault. This is extremely important conclusion, because the fault simulation was carried out at the transformer secondary, which is the closest to the BESS, and if the high side fuse cannot clear the secondary fault at this location, then it will definitely not be able to clear the fault anywhere downstream due to the effect of added line impedance.

![Image](image_url)

**Figure 101.** LG fault (phase A) on 480V bus at the customer load.

Since the faulted phase was phase A, aggregating all phase A currents for all 4 cases, we get the following graph on Figure 102 that shows the currents seen by the bayonet fuse located on the high side of the 12.47kV – 277V/480V transformer.

![Image](image_url)

**Figure 102.** Fault currents on the high side of 12.47kV – 277V/480V transformer.
Based on the graph, we can conclude that the 15A fuse cannot clear all faults and that this scheme will not result in the desired level of reliability and security scheme. The fault in this case was cleared by the relay that measures the neutral current in the grounding transformer. Similarly, the BESS undervoltage (27) protection could have protected the circuit, but in both cases, these two protection elements would have caused the whole microgrid to black-out. This is not the most preferred approach, because any fault should be cleared in a way that minimizes the number of customers affected by the outage.

One of the contributions of this research is the new proposed protection and control scheme for reliably and securely detecting the faults on 277V/480V parts of the system without tripping the whole microgrid. The current sequence analysis on the high side of the transformer or equivalently at the upstream breaker B3 in this case, shows the following values on Figure 103. As can be seen from the figure above, negative- and zero-sequence currents during the fault conditions are significantly higher than their steady-state values. For that reason, the new proposed scheme includes the use of these two sequence networks torque-controlled with voltage sequence network elements as defined in this section.

![Sequence currents on the high side of 12.47kV – 277V/480V transformer.](image_url)
Set-point for negative-sequence current I₂ can be calculated as:

\[ I_{2\text{MAX}} = (1.1 * I_{2\text{LOAD MAX}}) * 110\% = (1.1 * 0.52A) * 110\% = 0.63A\]

\[ I_{2\text{PU}} = 1.5 * I_{2\text{LOAD MAX}} = 1.5 * 0.63A = 0.95A\]

Chosen curve is U3 and time dial is 0.5. Similarly, set-point for zero-sequence current I₀ can be calculated as:

\[ I_{0\text{PU}} = 150\% * I_{0\text{LOAD MAX}} = 150\% * 0.52A = 0.78A\]

### 7.4.1. Microgrid LG fault on secondary side (277/480V) – field testing

In order to test the new protection and control scheme, LG fault was placed on the secondary side of 1000kVA 12.47kV – 277V/480V transformer located within the electric utility’s microgrid. The microgrid, was separated from the grid, and the load within the microgrid (warehouse building with research and development engineers) was switched to the alternate power supply. DER resources within the microgrid were BESS and PV, and load within the microgrid was kept at 0.30 p.u. using the load bank. Figure 104 below shows the microgrid yard with medium and low voltage elements and location of LG fault, while Figure 105 shows the electrical one-line diagram for the microgrid yard.

![Microgrid yard showing the location of LG fault on 277V/480V.](image)

Figure 104. Microgrid yard showing the location of LG fault on 277V/480V.
LG fault was placed on the low side of 1000kVA 12.47kV - 277V/480V transformer. Measurements were recorded at several locations within the microgrid, and at each location, protective elements were added within the relay based on the analysis above.

In the field implementation, in order to minimize the fault duration, protection was designed to trip within 2 cycles based on the neutral overcurrent $I_0$ setting. LG fault was placed within the microgrid by closing the 480V breaker that was connected to the ground through the fused disconnect switch. Upon closing the breaker, the microgrid protection operated as expected, and the microgrid tripped within 2 cycles (29.688ms) based on the neutral overcurrent setting, which was as designed, as shown on Figure 106 below. As seen from the figure, there is a delay of approximately of 7ms between the pickup setting of 4.0A and the actual time when this element starts timing out. This is due to the processing delay associated with A/D converters within the relay microprocessor. Depending on the vendor and relay model, sampling rates differ (2ms, 4ms, etc), and this delay has an impact on the relay timing. As expected, this element has performed properly. In order to check if voltage sequence elements used for torque control have operated as expected, relay fault data was imported in SEL 5601-2 software. Note that every figure in the analysis below will have orange vertical line showing the fault detection time and purple vertical line showing the TRIP time from the grounding transformer as a reference. Based on the analysis,
time delay for grounding transformer TRIP output will subsequently be adjusted in order to enable the proper coordination.

![Grounding transformer neutral current IN](image)

**Figure 106.** Grounding transformer neutral current \( I_N \).

Figure 107 shows the results of voltage sequence network analysis. As seen from the analysis, positive-sequence element \( V_1 \) is in \([0.39-0.64]\)p.u. range, which is close to the simulated \([0.47-0.59]\)p.u. range.

![Voltage sequence networks during LG fault on 277V/480V side](image)

**Figure 107.** Voltage sequence networks during LG fault on 277V/480V side.
This element can be used for the reliable and secure protection and control, it is below its 27P1P setpoint during the whole duration of the fault. Even though the fault clears around 130ms mark, it takes the additional 40-50ms for BESS to stop switching the IGBTs, and for that reason, all three voltage sequence networks are still present after all breakers have tripped.

The analysis of fault currents on the high side of the 1000kVA transformer is shown on the Figure 108 below. As seen from the graph, the fault current on the transformer high side exceeds its nominal rating and it reaches 1.85 p.u., but it never reaches the fuse rating, which is similar to the simulation result (with the notion that during the simulation, the expected fault current rating was 1.52 p.u.). However, if we assume that there is a recloser upstream from the high side of the transformer, which in this case is breaker B3, and if we look at the voltage and current phase sequence networks at this location, we can notice that the voltage sequence networks are the same as shown on Figure 107.

![Figure 108. 1000kVA transformer high side fault current.](image)

This is expected, since 1000kVA transformer and B3 are very close in the field. The only difference between this case and the feeder where recloser is located at a distance from the transformer is that
the sequence networks would have been slightly different in terms of values for \( V_1, V_2 \) and \( V_0 \), but the same conclusion could be derived in terms of protection and control methodology.

Because the fault in the field was LG fault, all three current-sequence networks \( I_1, I_2 \) and \( I_0 \) as shown on the Figure 109 below have the same value. As seen from the graph, both \( I_2 \) and \( I_0 \) can be reliably used for the LG fault detection, since there is enough margin between the set-points (0.15 p.u.) and fault current sequence values. Field measured value for \( I_2 \) of 0.81 p.u. is significantly higher compared to the simulated value of 0.35 p.u., which is better from protection standpoint given the higher margin between the pick-up value of 0.15 p.u. Current \( I_0 \) field measured value of 0.86 p.u. is also significantly higher than simulated value of 0.48 p.u, which is also better from protection standpoint given the higher margin between the pick-up value of 0.15 p.u. Per unit settings are based on the total maximum kVA output of BESS, which is the limiting factor for the fault current in this case. As described above, microprocessor-based relays were added between the inverter AC output and low side of DER transformer for both BESS and PV.

Figure 109. Upstream recloser current sequence networks.
Figure 110 shows the phase currents as seen by the relay installed on the AC side of the BESS inverter. Fault currents seen by this relay are 1.945 p.u. on phase A (faulted phase), 1.01 p.u. on phase B and 0.864 p.u. on phase C. As a result, BESS phase overcurrent element can be reliably used for detection of LG low voltage faults like simulations (1.845 p.u. for the faulted phase).

![Graph of phase currents](image)

**Figure 110. BESS phase currents for LG fault on the transformer secondary.**

Typical phase overcurrent element pick-up setting for the in this case is 1.25 p.u. However, in typical field implementations, BESS inverters limit the fault current to a much lower value (in the actual field implementation, BESS inverter has a limit of 2.4 p.u., while some BESS inverters have this limit at 1.20 p.u.), and for that reason, typical 50/51 phase overcurrent element cannot be used as a secure and reliable protection element for every DER inverter.

Figure 111 below shows the positive- and negative-sequence currents as recorded by the new proposed BESS relay. As seen from the graph, only negative-sequence overcurrent element can reliably be used to detect the LG fault (field measured value of 0.94 p.u. vs simulated value of 0.92 p.u.). Even though this protective element is faster than typical 27/59/81 elements associated with BESS controller, it would result in the whole microgrid blackout.
Graph on Figure 112 shows voltage and current sequence elements. As seen from the graph, only positive-sequence voltage element (V₁) can be used as a torque-control element, because it is constantly picked-up. Negative-sequence voltage element (V₂) oscillates between [0.12-0.44]p.u. and occasionally picks up, while zero-sequence (3V₀), which is in range of [0.05 - 0.11]p.u., never picks-up. Because the BESS installed within the microgrid can provide the maximum fault currents up to 2.4p.u., in this case the traditional overcurrent element (50) can be used as a protection element, because during the fault, phase current reaches the value of 1.92p.u. However, majority of the inverters available on the market today can produce the fault currents in much lower range [1.2-1.4]p.u., which cannot be used as a reliable protection and controls element. As expected, negative-sequence overcurrent elements (I₂) on both BESS and B3. In addition, zero-sequence overcurrent element (I₀) on breaker B3 also can be used as a protection element. TRIP BESS element is based on the phase and negative-sequence overcurrent elements torque-controlled by the positive-sequence undervoltage elements, but it is delayed by 200ms (TRIP BESS TD), because of the relay coordination with breaker B3. TRIP B3 element is based on the negative- and
zero-sequence overcurrent elements torque-controlled by the positive-sequence undervoltage elements.

![Voltage and current sequence network elements](image)

Figure 112. Voltage and current sequence network elements.

7.5. **Protection scheme for the faults on secondary side (120/240V)**

The last fault that needs to be implemented is the fault on 75kVA transformer which feeds the 120V/240V customer load. The main challenge in this case is to determine if this fault could potentially be cleared by the fuse on high side of this transformer or by any of the relays within the microgrid. Typical rating for the fuse on the high side of the 75kVA transformer that is rated at 12.47kV – 120V/240V is 25A. For this fault, only one use case is considered, which is that case when the overall load within the microgrid is at its minimum, which is 0.3 p.u. with BESS as the only operating DER. Baseline values for the transformer high and low side are shown in Table 40.

Table 40. Microgrid baseline values for the customer with 120V/240V system

<table>
<thead>
<tr>
<th>Measurement</th>
<th>$I_A$ [A]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuse (75kVA XMFR high-side 12.47kV)</td>
<td>1.86</td>
</tr>
<tr>
<td>75kVA XMFR low-side - 120V</td>
<td>54.03</td>
</tr>
</tbody>
</table>
For the fault on the low side (120V/240V) on 75kVA transformer, DER fault current contribution is 1.60 p.u. and we get the following results shown on Figure 113 and in Table 41:

![Figure 113. L1-L2 fault on 120V/240V bus at the customer load.](image)

Table 41. Microgrid with LG fault on customer 120V/240V system

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>PCC Relay</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.57</td>
<td>0.69</td>
<td>0.12</td>
</tr>
<tr>
<td>GND XMFR Relay</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>11.17</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>PV Relay</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>11.17</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>BESS Relay</td>
<td>262.2</td>
<td>224.4</td>
<td>75.6</td>
<td>156.6</td>
<td>100.8</td>
<td>0</td>
<td>0.57</td>
<td>0.69</td>
<td>0.12</td>
</tr>
<tr>
<td>Fuse (75kVA XMFR high-side)</td>
<td>11.15</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>75kVA XMFR low-side - 120V</td>
<td>338.5</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Based on the analysis above, we can see that the fuse on the high side of the 75kVA transformer is not capable of clearing the fault on the low side of this transformer. Further analysis shows that the proposed addition of the negative- and zero-sequence based protection implemented at the upstream recloser can clear this fault, and back-up protection implemented within the grounding transformer can also clear this fault.
7.6. Protection scheme using 51VR element torque-controlled with Z₂ directional element

Traditional overcurrent relays operate when current exceeds the pick-up set-point for a pre-determined amount of time. Voltage restrained over-current element, or commonly known as 51VR element is typically used as a back-up protection for synchronous generators. During short circuits conditions, large fault current flows through the generator windings for a very short period of time. As the fault current increases, the voltage gradually decreases. Under this condition, traditional overcurrent element might not reach its pick-up value. In order to protect the generator in this condition, a two-element protection relay based on variable pick-up overcurrent value torque-controlled by the undervoltage relay based on the percentage of the nominal voltage level is typically deployed. This element provides the increased security of the overall generator protection scheme by setting the overcurrent value to be proportional to the applied voltage. Figure 114 shows a recloser on a distribution feeder with different protection elements.

![Diagram of recloser protection elements](image)

Figure 114. New recloser protection elements.

The bottom three elements represent the new proposed protection and control scheme, due to the lack of security and reliability of the different traditional schemes. Figure 115 shows the relay 51VR protection element. Settings for 51VR protection elements are as follows:
1. $V_{\text{MAX}}$ - maximum line-to-line voltage of 1.0p.u. is the minimum voltage that is considered normal or healthy operating voltage within the microgrid. For this purpose, $V_{\text{MAX}}$ voltage is chosen to be 0.90p.u. of the nominal line-to-line voltage - $V_{\text{MAX}} = 0.9 \times V_{\text{LL}}$ (in protection and control arena, voltages below 0.85p.u. are considered abnormal).

2. $V_{\text{LL}}$ - minimum voltage of 0.125p.u. is the minimum voltage during the fault and can be calculated as $V_{\text{MIN}} = 0.125 \times V_{\text{MAX}}$.

3. $I_{\text{MAX}}$ - because 51VR element is not secure enough and operates for some system loading conditions, the maximum current $I_{\text{MAX}}$ of 1.0p.u. is set at 150% of the full load current.

4. $I_{\text{MIN}}$ - the minimum current is set at 12.5% of the $I_{\text{MAX}}$.

Typical time delay for the 51VR element is typically set at 0.5 seconds after overcurrent time-delay overcurrent (51) element and directional element (67).

Traditional approach for 51VR protective element, as noted before, includes the implementation of this element as a back-up protection for synchronous generator. However, given that the traditional overcurrent protection is not secure and reliable when it comes to the microgrids operating in islanded mode with inverter-based DERs due to the low fault currents, this paper
proposes the new approach - using 51VR element as the one of the two main protection overcurrent elements implemented within breakers and line reclosers. In order to make the 51VR element secure and reliable, the new proposed approach also includes using the negative sequence impedance element $Z_2$ and positive-sequence T32P element as torque-controlling elements for 51VR element, in order to provide the directionality function.

In order to determine if 51VR element can be used to detect the faults within the microgrid, this protection element was built in MATLAB. Simulation of the microgrid was carried out for 5 seconds, and the following Figure 116 shows several operating conditions that were simulated in order to ensure that the new protection element does not erroneously operate during transient condition. From 0-2sec, microgrid operated in grid-connected mode. At 2s, seamless islanding transition took place, and grounding transformer was connected to the microgrid in order to provide the effectively grounded microgrid. At 4.25sec, LG fault was placed within the microgrid, and the fault cleared at 4.5 cycles. In addition, several transient operating conditions were simulated (such as motor start, capacitor bank switching, etc.).

![Figure 116. Microgrid simulation – chronology.](image)

51VR protection element was designed and built in following six steps:

1. Determine the minimum line-to-line voltage during the LG fault - Figure 117 shows all three microgrid line-to-line voltages and $V_{CA}$ voltage (blue line) was found to have the lowest voltage during the LG fault.
2. Determine the voltage limits for 51VR settings - as seen from the Figure 118, there are three voltages of interest. First, $V_{MIN}$ (red line) is the per unit representation of $V_{CA}$ minimum line to line voltage. Second, 51VR – Settings (green line) represents the voltage limits of the 51VR element setting of 0.90p.u. and 0.125p.u. for line to line voltages. Lastly, the 51VR – Settings (blue line) represents the actual per unit line-to-line voltage that was used in calculations with overcurrent constraints.
As noted before, $I_{\text{MAX}}$ setting should be at least 150% above the maximum load current. However, the 150% margin is designed for traditional power systems with synchronous generation. In case of microgrids with inverter-based DERs, this value is high because most DER inverters can hardly produce fault current levels in that range. For that reason, the margin can be reduced to a lower value.

3. Determine the RMS value of the maximum phase fault current as shown on Figure 119. The most challenging part of this analysis was to determine the maximum current setting $I_{\text{MAX}}$ because this can impact the security and reliability of the microgrid protection scheme. The authors have chosen this margin to be at 115%, because this value is torque controlled with another element. So, the new overcurrent settings were calculated as follows:

$$I_{\text{MAX}} = 115\% \times I_{\text{LOAD\,MAX}} = 115\% \times 4.63\,\text{A} = 5.32\,\text{A}$$

$$I_{\text{MIN}} = 12.5\% \times I_{\text{MAX}} = 12.5\% \times 5.32\,\text{A} = 0.67\,\text{A}$$

![Figure 119. B4 – fault currents.](image)

4. Determine the overcurrent pick-up value as a function of the Voltage - using CT ratio of CTR=500:1 from the field implementation, the 51VP pick-up setting is then calculated as:
\[ 51VP = \frac{l_{MAX}}{CTR} = \frac{5.32A}{500} = 0.01 \]

Since minimum relay pick-up is 0.05, this will be used as 51VP value moving forward. Chosen relay inverse curve (U3) has a time dial (TD) of 0.5. From here, 51V pick-up setting can be calculated simply as the product of the 51VP pick-up setting and the Voltage as a function of time:

\[ 51V_{PU} = 51VP \times \text{Voltage} \]

5. Determine when the 51VR protection element (51V_{PU}) picks up - this occurs when the maximum value of the RMS current as shown on Figure 119 divided by the CTR is greater than the 51VP pick-up setting:

\[ \text{If } \max(I_{A RMS}, I_{B RMS}, I_{C RMS}) \geq 51V_{PU} \Rightarrow 51VR = 1, \text{ else } 51VR = 0 \]

6. Determine the trip time of the 51VR element - this calculation is based on the standard operating time for the U2 inverse curve from [42]:

\[ \text{trip time} = TD \times \left( \frac{A}{M^p - 1} + B \right) \]

where TD is the time dial, A=5.95, M is the applied multiple of the pick-up current, p=2 and B=0.18. M can be calculated as:

\[ M = \frac{\max(I_{A RMS}, I_{B RMS}, I_{C RMS})}{CTR} \frac{CTR}{51V_{PU}} \]

Figure 120 shows the trip time for 51VR element. This analysis is done with respect to the implementation within breaker B2. Note that in the actual microgrid application, time delay of 200ms would have been included with respect to the same 51VR element implemented within the recloser R1. As seen from the graph, 51VR element picks up when both voltage and current are in TRIP region, and trip time based on the proposed overcurrent curve settings. However,
the element does not trip at the time determined by the 51VR supervised setting, because of the additional torque-controlled element.

![51VR element trip time – simulations.](image1)

Finally, Figure 121 shows the 51VR protection element operating in normal region, right before the fault, and its trajectory going from normal operation to TRIP region.

So far, we have determined that 51VR element can be used to detect the faults inside the microgrid with inverter-based DERs. However, this element is a non-directional element and as we know, microgrid can have multiple DERs located at any location.

![51VR element – I-V curve.](image2)

In order to minimize the number of customers that might be affected by the faults, the authors propose to have 51VR element torque-controlled by two directional elements - T32P and Z2.
Directional elements are typically used to determine the fault direction, but they are not used to trip the breaker. For that reason, they are used to supervise the elements (in this case 51VR) that trip the breaker. In this paper, the authors propose the use of T32P and $Z_2$ directional elements.

Equivalent circuit for 3Φ faults (LLL/LLLG) consists only of positive sequence-current element and for that reason, positive-sequence directional element T32P that uses positive-sequence voltage and current quantities, is used in order to provide the directionality:

$$T32P = |3V_1| \times |3I_1| \times \cos(\angle 3V_1 - (\angle 3I_1 + \angle 3Z_{L1}))$$

where,

- $3V_1$ - positive-sequence voltage and polarizing quantity,
- $3I_1$ - positive-sequence current,
- $\angle Z_{L1}$ – positive-sequence line angle, and
- $3I_1 \times (1\angle Z_{L1})$ is the operating quantity.

The sign of T32P for the forward faults is positive and it is negative for the reverse faults. When operating and polarizing quantity are small, the direction based on T32P can become unreliable, so a minimum threshold for this element is required before this element is enabled. Because T32P element cannot be used to detect the direction for unbalanced faults (LG, LL and LLG), negative sequence directional element (T32Q) and zero-sequence directional element (T32V) have been introduced. The main challenge with implementation of both T32Q and T32V directional elements is the fact that during the fault within the microgrid with inverter-based DERs, the fault current levels are small compared to the microgrid that operates in grid connected mode. Therefore, both voltage and current polarizing quantities during the fault might be small and not capable of polarizing the directional element. For that reason, when the polarization quantity at the relay is low to polarize the directional element, the compensation quantity is added in order to
boost the polarization quantity. In essence, the relay at a particular location on the feeder could be “relocated” further down closer to the fault, where the polarization quantity is higher. The authors propose the use of the negative-sequence impedance element $Z_2$ as the directional element for asymmetrical faults, which is defined as:

$$Z_2 = \frac{\text{Real} \left[ V_2 * (I_2 * 1 \angle \Theta)^* \right]}{|I_2|^2}$$

where $Z_2$ is the negative-sequence impedance and $\Theta$ is the angle of negative-sequence line impedance. Figure 122 shows the settings plane for the $Z_2$ element.

![Figure 122: Z2 directional element - settings plane.](image)

Set-points were defined as follows: $Z_{2F} = -0.5$ and $Z_{2R} = 0.5$. From here, the threshold levels for forward and reverse fault were calculated as:

$$Z_{2F\, THRESHOLD} = 0.75 * Z_{2F} - 0.25 \frac{V_2}{I_2}$$

$$Z_{2R\, THRESHOLD} = 0.75 * Z_{2F} + 0.25 \frac{V_2}{I_2}$$

If $Z_2 < Z_{2F\, THRESHOLD}$ then the fault is in forward direction and if the $Z_2 > Z_{2R\, THRESHOLD}$ then the fault is in reverse direction. If the impedance $Z_2$ is within the two threshold set-points, the system operates in normal mode. In traditional protection, $Z_2$ element must be supervised by the overcurrent condition of some type. For that reason, typically negative sequence current (50Q1P)
exceeding some value would need to be defined. However, this is not easily designed and implemented when it comes to the microgrids with inverter-based DERs. Due to the changing operating field conditions, availability of DERs, time of the day, this value 50Q1P would always change. For that reason, the authors here propose using different approach for supervising element. Under the normal operating conditions, negative-sequence current and voltage elements typically do not exceed 10% of the positive-sequence elements. In order to ensure that $Z_2$ element is properly supervised, the authors propose using the ratio of $3V_2/V_1 \geq 0.45\, \text{p.u.}$ and $3I_2/I_1 \geq 0.45\, \text{p.u.}$ to be the supervising element. Also, 2-cycle time delay is also added to these ratios in order to increase the security of this proposed scheme. So, the new proposed protection and control scheme for microgrid now consists of 51VR element that is torque-controlled by $Z_2$ element for LG, LL and LLG faults, as well as torque controlled by T32P element for 3Φ faults. Figure 123 shows the trip time for the 51VR element torque controlled by $Z_2$ element during LG fault for each of the breakers B2, B3 and B4.

Figure 123. 51VR element torque-controlled by negative-sequence impedance element $Z_2$. 
7.6.1. Field testing – microgrid LG fault and 51VR element torque-controlled by $Z_2$

In order to test the effectiveness of the new proposed protection and control scheme that involves using 51VR element being torque-controlled by the negative-sequence impedance element $Z_2$, LG fault was placed within the electric utility’s microgrid. The microgrid, which can operate in islanded mode indefinitely, was separated from the grid, and the load within the microgrid (warehouse building with research and development engineers) was switched to the alternate power supply. DER resources within the microgrid were BESS and PV, and load within the microgrid was kept at 0.30 p.u. using the load bank. Measurements were recorded at several locations within the microgrid, and at each location, protective elements were added within the relay based on the analysis above.

In the field implementation, SEL 487E relay was used for the protection of the 4-way switchgear. This is differential relay, and it does not have 51VR protection element integral to its firmware. Because 51VR element is used only as a back-up protection associated with synchronous generators, only generator protection relays (which in case of SEL are 300G and 700G relays) have this protection element. This protection element is not part of traditional distribution feeder relays (like SEL 351 or SEL 651R) nor differential relays (like SEL 487E). For that reason, 51VR element along with $Z_2$ directional element had to be separately designed. First, relay fault data was retrieved from SEL 487E relay and imported in SEL 5601-2 software. Second, both 51VR and $Z_2$ protection elements were programmed into the software using the same set of steps as described in the section above. Third, ground fault data from SEL 487E was replayed, and analysis was done to determine the effectiveness of this element. Figure 124 shows when the 51VR element picks up, its supervising element and the trip time. In the field implementation, in order to minimize the fault duration, protection was designed to trip within 2 cycles based on the grounding transformer.
neutral overcurrent $I_N$ setting. Upon fault occurrence, which occurred at 90ms mark, the microgrid protection operated as expected, and the microgrid tripped within 2 cycles (29.688ms). Figure 74 shows the times associated with fault current detection based on the grounding transformer neutral current and relay SEL 487E TRIP time based on the internal settings for 50N1P.

![Graph showing fault current detection times](image)

**Figure 124.** 51VR element – field relay TRIP time.

As can be seen from the graph, relay detects the fault shortly after the voltage enters the slope region of the setpoint curve (between 0.125p.u. and 1.0p.u.), which is tracked by the 51VR Supervised signal. Also, note that the reason why 51VR picked-up element went from 1 to 0 around 122ms mark is because the grounding transformer has cleared the fault, so the phase current has gone to zero. Nonetheless, the graph shows that the 51VR element successfully detected the ground fault. Note that in the actual feeder implementation case, the additional 0.2s time delay associated with relay coordination with the downstream recloser R1 would also be implemented.

Figure 125 shows the actual I-V trajectory during the fault within the microgrid. At first, microgrid operates in normal region (green area), but upon the occurrence of LG fault, the
trajectory of the I-V curve enters the TRIP region (red area), and after couple of cycles, the microgrid trips. However, this figure shows that the 51VR element has successfully detected the ground fault within the microgrid. Figure 126 below shows the same design of 51VR elements using SEL 5601-2 software.

![Diagram showing TRIP region and normal operation](image)

Figure 125. 51VR element – field data.

![Diagram showing B2 breaker 51VR protection element](image)

Figure 126. B2 breaker 51VR protection element using $Z_2$ element as a torque-control.
Second part of the proposed scheme is a $Z_2$ directional element, because in this case, microgrid has experienced ground fault (T32P element does not apply to ground faults). Figure 127 shows the effectiveness of the $Z_2$ directional element. As seen from the graph, both breakers B2 and B4 detect the forward fault, while B3 detects the reverse fault, which is as expected.

![Figure 127. $Z_2$ directional element – field results.](image)

This represents another positive result of the actual field verification, because based on the results, very little impedance (in this case BESS 1000kVA transformer with impedance of 5.69%) is needed to polarize the $Z_2$ element. Based on the analysis above, the following Figure 128 shows the final pick-up time for 51VR element torque-controlled by $Z_2$ for each of the breakers B2, B3 and B4. The reason for a slight delay compared to the previous figure is because each of the $Z_2$ elements is also supervised within the relay. The authors propose using both $3V_2/V_1 \geq 0.45$ and $3I_2/I_1 \geq 0.45$ and as supervising elements for $Z_2$. This setting comes from the fact that under normal conditions, negative sequence voltage and currents should not exceed 10% of the positive sequence value. Since relay measures $3V_2$ and $3I_2$ values, it is necessary to use 0.45pu set-point. In addition, relay also requires minimum negative sequence overcurrent current setting for $Z_2$ element. In this case, the authors propose using the dynamic overcurrent element that constantly changes as a
function of the actual load. The authors propose this minimum negative overcurrent setting to be greater or equal to the 15% of the positive sequence of the measured load current. Implementing all of these elements and programming them into the relay with fault data, as a result, we can see that 51VR element would pick-up at 104.18ms, which is the time when \( Z_2 B_2 \) picks-up providing the torque-control to the breaker B2 that the fault is in forward direction.

![Figure 128. 51VR element TC by \( Z_2 \) - pickup-time.](image)

This occurs approximately 12ms after the fault occurrence, which proves that the proposed element was successful in reliably detecting the ground fault within the microgrid. Figure 129 shows the design and build of \( Z_2 \) directional element using SEL 5601-2 software.

**7.6.2. Conclusion – 51VR element torque-controlled by \( Z_2 \)**

Microgrids with inverter-based DERs have major challenge when it comes to designing reliable and secure system protection and control scheme due to the low fault currents compared to the grid connected operating mode. Traditional feeder protection based on phase and ground overcurrent (50/51) elements cannot be used as primary feeder protection.
The main objective of this section was to introduce the new methodology for reliable and secure microgrid operation for ground faults using 51VR element torque-controlled by $Z_2$ and T32P elements. Both simulations and field results from the microgrid show that this element can be used as one of the two primary protection elements, effectively replacing the traditional phase and ground overcurrent elements. DER inverter response during the fault, unlike synchronous machines, is not uniform. Depending on the inverter vendor, controls design, operating modes, availability of voltage and current sequence networks during the fault and a host of other conditions, new protection and control scheme proposed in this document might not always result in the same response.

In order to achieve the security of this scheme, $Z_{2F}$ limit must be less than $Z_{2R}$ element in order to avoid a condition where $Z_2$ can potentially satisfy both forward and reverse fault conditions. Some DER inverters, during the fault, intentionally suppress the voltages and as a result, the magnitude of the measured negative-sequence voltage $V_2$, which is also influenced by
the negative-sequence current $I_2$, needed to polarize the $Z_2$ can be small that, as a result, $Z_2$ can be close to zero. In this case, it is necessary to increase the value for $Z_{2F}$ element, which increases the apparent magnitude of the negative-sequence source impedance behind the relay. Figure 130 shows the simulation of the LG fault within the microgrid on the feeder with two DERs with lower fault current capability. As seen from the graph, recloser R1 at the midpoint is capable of tripping on 51VR element, because the negative-sequence voltage can polarize the directional element $Z_2$. However, for all locations on the feeder where the levels of negative-sequence voltage is lower than 59Q1P setting, $Z_2$ element cannot polarize and therefore, the value of $Z_{2F}$ must be increased in order to solve this problem and enable the secure and reliable operation of 51VR element.

![Figure 130. Voltage sequence networks for LG fault.](image)

In order to overcome the potential shortcoming of 51VR protection element for inverters with low fault current contribution, the authors have developed a new protection element for the microgrid protection and control scheme that does not have these challenges. The element - rate of change of current sequence networks ($\Delta I_{1,2,0}/\Delta t$) and use of the 10th order Butterworth low-pass filter with cut-off frequency of 240Hz - is covered in the next section. Note that the traditional low-
pass filter used in microprocessor-based relays is one-cycle cosine filter. In this case, new filter with flatter 60Hz response has been proposed and implemented.

7.7. Protection based on the rate of change of current sequence networks with 10th order Butterworth filter and 240Hz cut-off frequency

Most of the protection schemes in modern relaying are based on the concept of analog value exceeding the user-defined setpoint. However, [42] has few device numbers based on the rate of change - rate of change of gas (61), rate of change of pressure (63), rate of change of level (71), rate of change of flow (80) and rate of change of frequency (81R). Other than 81R element, which is used for islanding detection, all other elements have inputs from mechanical devices. For that reason, microprocessor-based relays today do not have the rate of change of current protection element as an option as part of their firmware. Review of the literature shows few approaches to microgrid protection and control using the traditional overcurrent elements, but there is hardly any information about the use of rate of change of current as protection methodology. Variable speed drives (VSD) have overcurrent protection typically around 200% of the drive rating, which limits the current between 150% - 180%. Sometimes, in order to maximize the VSD rating, the rate of change of current is controlled by using the choke. However, this method is not applicable to microgrids. Review of the literature associated with microprocessor-based relays available on the market today also revealed that no single relay today has a rate of change of current as a protection and control element available.

The basic premise of the new approach lies in the fact that during the fault, there is always a change in voltage and current measurements. Traditional overcurrent protection approach uses the pre-determined current set-point and time delay in order to detect the fault. As noted before, fault currents within microgrids with inverter-based DERs operating in islanded mode are significantly lower compared to the grid connected faults and the fault current levels and load
current levels typically overlap, making the traditional overcurrent protection approach not applicable. However, during the fault, currents within the microgrid change, and the new approach to the microgrid P&C relies on the change of the current sequence networks in order to detect the fault condition. The idea came from looking at the principle of operation of traditional CTs and Rogowski coils. Conventional iron-core CTs have windings that are wound around the iron core and their output is either 1A or 5A current, which is proportional to the primary current. The output current (1A or 5A) then drives the low impedance relay input. On the other side, conventional Rogowski coil windings are wound around air core. Because Rogowski coils are wound around air core, which is nonmagnetic, their output is linear and, unlike traditional CTs), they cannot go into saturation. However, that causes weaker coupling between the primary conduction around which the Rogowski coil has been wound and the secondary winding in the Rogowski coil. This weaker coupling prevents the output of the Rogowski coil to be driven into low resistance input. For that reason, Rogowski coils produce the voltage output, that represents the rate of change of primary current (di/dt), which is then driven into high impedance input.

During a fault within the microgrid with inverter-based DERs operating in islanded mode, measured phase currents reach levels in the range of 1.2-1.4 p.u., which is significantly less than the faults in grid-connected mode, but nonetheless, there will be increase in a phase current during the fault. The new approach relies on measuring the rate of change of the current sequence networks that was caused by the fault and understanding if these elements can be used as a reliable and secure microgrid P&C elements. The approach will include analyzing the rate of change of phase currents $\Delta I_{A,B,C}/\Delta t$ as well as the rate of change of current sequence networks $\Delta I_{1,2,0}/\Delta t$. 
7.7.1. $\Delta I_{A,B,C}/\Delta t$ P&C elements

As noted before, phase currents during microgrid faults are typically in 1.2-1.4 p.u. range and traditional overcurrent protection is reliable and secure. During feeder faults, phase currents will increase, and there will be a rate of change associated with this magnitude increase. The analysis presented in this paper covers three responses: phase currents and current sequence networks, rate of change of phase currents/current sequence networks and the most significant parameter that the authors propose in this paper - 60Hz signal of rate of change of phase currents/current sequence networks. So, why is the last response the most significant parameter?

In order to measure the analog signals from the field, such as voltages and currents, microprocessor-based relays analog input cards are wired to the output of respective potential transformer (PT) and current transformer (CT).

![Figure 131. Relay Input Processing.](image)

The signal first goes through an analog low-pass filter, and then, it is sampled at a defined rate, which can be a function of the nominal system power frequency, measured power system frequency or it might not be a function of the power system frequency. Protection functions within the relay use 8kHz sampling frequency. In order to provide the accurate time, GPS clock is
connected to the relay that uses IRIG-B signal. Signal at the output of 8kHz A/D converter includes the DC offset along with all the harmonics. For that reason, a digital filter, which is typically one-cycle cosine filter, which has zeros at the DC value and multiples of 60Hz frequency and has a good transient response is implemented in order to produce the fundamental frequency (60Hz) signal. The main requirement for the proper operation of the filter is that it has an integer number of samples per each cycle. Following, all relay protection logic is then based on the magnitude and angle of the fundamental signal. Relay input processing architecture for SEL relays, used in the actual utility microgrid, is shown on Figure 131 [65].

Using the same simulation window of 5 seconds as shown on Figure 116, Figure 132 shows the breaker B3 phase currents (top) and rate of change of phase currents (bottom). As seen from the top graph, phase current increases during LG fault but the maximum fault current level on phase A is slightly higher than the maximum load current, so traditional overcurrent protection cannot be reliably implemented in this case.

![Figure 132. Phase currents during microgrid LG fault.](image)

Bottom graph, which shows the rate of change of phase current, shows several spikes during the 5 seconds of simulation, and this response does not look like anything that could potentially be
used as part of the relay protection and control scheme. However, this conclusion is misleading, because this graph shows the rate of change response that includes the DC offset and all harmonics. For that reason, a filter must be implemented here in order to extract the fundamental (60Hz) signal. Traditionally, relays have been designed to use one-cycle cosine digital filter in order to accomplish this task. In this case, the authors propose using Butterworth filter, which is a low-pass filter that has a no ripple response between the DC (0kHz) and user-defined cut-off frequency $f_c$, which is at -3dB. At frequencies higher than $f_c$, the frequency decreases at the rate of 20dB/decade. Equation that represents the generic ”n-th” order Butterworth filter is given by:

$$H(j\omega) = \frac{1}{\sqrt{1 + \epsilon^2 \left(\frac{\omega}{\omega_p}\right)^2 n}}$$

where,

- $n$ - order of the filter,
- $\omega=2\pi f$ - maximum gain within the band, and
- $\omega_p$ - band-pass frequency.

Two main design components of the Butterworth filter are the order and cut-off frequency. First, cut-off frequency in this case is a function of the number of samples per cycles that the relay uses in its input processing. For SEL 487E relay, which has been used in the microgrid field implementation and testing, the number of samples per cycle is 8 (this relay has internal relay processing time of 2ms). Based on this value and the fact that $f_s > 2f_n$, where $f_s$ is a sampling frequency and $f_n$ is a Nyquist rate frequency, the cut-off frequency is 240Hz. Figure 133 below shows the characteristics of the lowpass Butterworth filter with $f_c = 240Hz$ as a function of a different order. As seen from the graph, the higher the order of the filter, the better the rate of the falloff response it has. This rate depends on the number of the poles in the circuit, which depends on the number of reactive elements (capacitance and inductance) in the filter circuit.
In this case, the authors propose using the 10th order filter, because it offers the optimum response. Figure 134 shows the fundamental frequency (60Hz) signal associated with the rate of change of phase currents during the microgrid simulation. As seen from the figure, the rate of change of phase currents is always present because of the changing field conditions, regardless of whether the microgrid is grid connected or islanded. Phase current change is associated with any change of operating condition within the microgrid, and as such, it is hard to discriminate between the faults and the normal change of operating conditions. As such, the rate of change of phase currents protection approach can negatively affect the security of the protection and control scheme, because it might erroneously TRIP the feeder, when there is no actual fault on the feeder. For that reason, the authors propose using the rate of change of current sequence networks in order to detect faults within the microgrid, because they are more sensitive to the fault and offer greater security and reliability.
Figure 134. Rate of change of phase current - 60Hz signal response.

7.7.2. $\Delta I_{1,2,0}/\Delta t$ P&C elements

Fault currents can be modelled as a combination of three current sequence networks: positive ($I_1$), negative ($I_2$) and zero ($I_0$). In order to be able to successfully implement this analysis, it is necessary to know which sequence currents are present during different faults:

1. LG fault: $I_1$, $I_2$ and $I_0$
2. LL fault: $I_1$ and $I_2$
3. LLG fault: $I_1$, $I_2$ and $I_0$
4. 3Φ faults: $I_1$

In order to assess the effectiveness of the new proposed approach, rate of change of positive- ($dI_1/dt$), negative ($dI_2/dt$) and zero-sequence ($dI_0/dt$) networks has been recorded during the same 5 second simulation of the microgrid along with its fundamental (60Hz) response. Figure 135 shows the response associated with the rate of change of positive sequence current $dI_1/dt$ (top) and its fundamental signal (60Hz) response (bottom). As seen from the graph, 60Hz response effectively filters most of the transients within the microgrid. Note that during the transition from
grid to island at t=2s (and grid synchronization), this protection is disabled, because of the need to increase the security of the proposed P&C scheme.

According to the graph, filtered 60Hz signal can be used as for the fault detection, because the rate of change of positive sequence current as recorded at 4.25s (fault occurrence) is significantly higher than any change during the normal operation of the feeder. Negative-sequence current $I_2$ is very sensitive to ground faults, so it is expected that the rate of change ($dI_2/dt$) is more significant compared to the $dI_1/dt$.

Figure 136 shows the rate of change of negative sequence current $d3I_2/dt$ (top) along with its fundamental signal (60Hz). As can be seen from the graph, the filtered version removes all harmonics, so the margin above the steady-state value in this case is more significant compared to the $dI_1/dt$. Like the behavior of negative-sequence currents during LG faults, zero-sequence current $3I_0$ is also very sensitive to ground faults. It is also expected that the rate of change of zero-sequence current ($d3I_0/dt$) is more significant compared to the $dI_1/dt$. 
Figure 136. Negative-sequence current ($3I_2$) during microgrid LG fault.

Figure 137 shows the rate of change of zero sequence current $d3I_0/dt$ (top) along with its fundamental signal (60Hz). As can be seen from the graph, the filtered version removes all harmonics, so the margin above the steady state value in this case is more significant compared to both $d3I_0/dt$ and $dI_1/dt$. All graphs above showing the rate of change of current sequence networks have also 60Hz filtered signal. Microprocessor based relays today use 60Hz signal in order to make protection decisions.

Figure 137. Zero-sequence current ($3I_0$) during microgrid LG fault.
As noted before, relays today mostly use one-cycle cosine filter. In recent years, there are couple of implementations of micro-processor based relays with unfiltered data, where faults in the vicinity of the wind farms have been found to be detected only if unfiltered signal was used. However, looking at the graphs of the LG fault response, using filtered signal with fundamental (60Hz) response proves to be the best approach. In this case, authors propose the used of Butterworth filter, and as noted before, the cut-off frequency was chosen to be 240Hz. Regarding the order of the filter, the fault at 4.25s mark was simulated with different filter order and response was recorded and shown on Figure 138.

![Butterworth filter – order design.](image)

As seen from the graph, the optimum order of the proposed Butterworth filter is 10, because it offers the smoothest response that could be used to detect the faults. This result is the same result obtained during the simulation shown on Figure 133. The final step left in the proposed approach is to determine the settings for the rate of change of current.
Figure 139 shows the maximum values for the rate of change of three current sequence networks during the steady-state islanding operation compared to the rate of change during the fault, while Table 42 summarizes the results from the graph above. Based on the simulation results, it appears that the rate of change of zero-sequence current has the highest margin between the maximum steady-state value and maximum value during the ground fault (35.63x).

<table>
<thead>
<tr>
<th>Element</th>
<th>Steady-state</th>
<th>Max. value</th>
<th>Ratio</th>
<th>Setting</th>
</tr>
</thead>
<tbody>
<tr>
<td>dI1/dt</td>
<td>132.8</td>
<td>430.6</td>
<td>3.24</td>
<td>265.6</td>
</tr>
<tr>
<td>d3I2/dt</td>
<td>390.4</td>
<td>1378</td>
<td>3.52</td>
<td>780.8</td>
</tr>
<tr>
<td>d3I0/dt</td>
<td>41.7</td>
<td>1486</td>
<td>35.63</td>
<td>83.4</td>
</tr>
</tbody>
</table>

For that reason, using set-point of 200% of the maximum steady state value of 41.7A/s or equivalently 83.4A/s, the protection and control logic would issue a TRIP signal for the ground fault. As seen from the graph, the rate of the change of current element does not last long (sub-cycle time), so based on this analysis, this set-point should have 0 cycle delay. As noted before, rate of change of positive- and negative-sequence current elements could also be set at 200% of their maximum steady-state rating, but the margin above the setting is close to the maximum fault
value during the fault, that these two elements might not operate prior to operation of $d3I_0/dt$ element.

7.7.3. Field testing – sequence-currents rate of change ($dI/dt$)

In order to check if the proposed $dI_{1,2,0}/dt$ P&C elements operate as shown in simulations, microgrid LG fault data was retrieved from SEL 487E relay in from of a COMTRADE file and it was imported in SEL 5601-2 software for the analysis. Since traditional relays do not have the rate of change of current (both phase and sequence) P&C elements, the functionality was programmed into the software in order to analyze how the relay would have behaved during the fault using the current rate of change elements. Figure 140 show the positive-, negative- and zero-sequence currents (top) along with the rate of change of the same currents sequence networks (bottom) associated with Breaker B4.

![Figure 140. dI/dt – breaker B4.](image)

Figure 141 shows the same analog quantities for breaker B3. As expected, breaker B3 values are higher compared to breaker B4 due to the fault contribution from grounding transformer connected to breaker B2. Note that in this case, the faults was cleared within 2 cycles, so the actual response for the rate of change of currents is a little bit more extreme that otherwise would have been,
because typical faults last in the 250ms range. However, settings regarding the current rate of change are determined based on the response within the first couple of cycles, so this response is sufficient.

The following Table 43 summarizes the results from the graph and as seen from the results, the rate of change of current sequence network values seems to be significantly higher than simulated values.

<table>
<thead>
<tr>
<th>Element</th>
<th>Steady-state</th>
<th>Max. value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$dI_1/dt$</td>
<td>155</td>
<td>4203</td>
</tr>
<tr>
<td>$d3I_2/dt$</td>
<td>478</td>
<td>12320</td>
</tr>
<tr>
<td>$d3I_0/dt$</td>
<td>993</td>
<td>12320</td>
</tr>
</tbody>
</table>

One of the reasons for such behavior might be the fact that the size of the BESS is four times of the unit used in simulations and the maximum fault current contribution is 2.4 p.u., which is higher than the maximum fault current contribution used in the simulations by 70%. This is also another lesson learned, because based on the simulations and actual field fault, it appears that the size of the BESS and it fault current capability directly affect the set-points for the rate of change.
of current sequence networks. In the same way, steady-state values were also higher. Note that in this case, steady-state values were taken immediately before the fault, so the maximum value in this table is not the actual representative of the true maximum values (note that this microgrid does not have the capacitor bank due to the low load and maximum motor size is 10kW). Nonetheless, the rate of change of current sequence networks is significant, so this approach can be used for microgrid protection and control.

As a side note, in order to further prove the validity of the new approach, electric utility microgrid was simulated using the RTDS Hardware-in-Loop (HIL) system with three relays connected to the model using the actual field settings as shown on the Figure 56 below. First, generic control models used in simulations associated with generic microgrid for BESS and PV were used in the initial modelling effort. Following, the data from the actual microgrid LG fault was used to fine tune the model until it provided similar response with respect to the voltage and current outputs of two DERs, as well as the LG fault current and fault current seen by the neutral CT of the grounding transformer. Errors of 5% in fault current data were considered acceptable. SEL 787 and SEL 751 relays were used for the grounding transformer protection, while one SEL 487E transformer was used for BESS transformer protection. Second SEL 487E relay was used for the protection of the 4-Way switchgear. Since relays do not have the rate of change of current functionality inherent to their settings, this functionality was programmed into this relay. Fault was placed at the location F4, and relay Comtrade file associated with the actual microgrid field LG fault at the same location was played back into the signal data generator. Response of the new relay elements capturing the rate of change of sequence currents was recorded in new relays and Figure 142 and Figure 143 below show the response. As seen from both figures, the response recorded is similar to the response obtained from the analysis using SEL 5601-2 software.
The rate of change of negative- and zero-sequence currents associated with breaker B3 are larger compared to the same response for breaker B4, which is expected, because of the contribution to the fault from the grounding transformer. The rate of change of positive-sequence current network is significantly lower compared to the other two responses. Note that the additional HIL simulation was a group effort with two engineers from SEL, Inc. Rona Vo and Lee Luis.

7.7.4. Conclusion – sequence-currents rate of change (dI/dt)

Design of secure and reliable P&C scheme for microgrids with inverter-based DERs presents the new challenges due to the low fault current levels. This section introduced the second new P&C element based on the rate of change of current sequence networks - dI_{1,2,0}/Δt. Both simulations and the actual microgrid fault current analysis showed that the new proposed P&C
elements can be successfully used for the islanded microgrid fault detection. As a result, the main recommendation of this research is to replace the traditional phase and ground overcurrent based P&C elements with rate of change of current sequence network elements. However, additional work and field experience is needed to confirm the behavior of these elements associated with fault current response of different inverters. Unlike the fundamental (60Hz) frequency fault response of synchronous generators, which is the MVA rating and impedance are the same, fault current response by DER systems today is different and depends on many things (vendor, inverter control design, etc...). For that reason, additional element(s) might be needed as part of the scheme to be used as a torque control element in order to provide the reliable and secure overall protection and control scheme for microgrid.
 CHAPTER 8: Microgrid Protection and Control During Seamless Transition to Island and Grid Synchronization

8.1. Seamless transition - background

Transition from grid-connected to islanded operating mode and grid synchronization of a microgrid are done either by enabling seamless transition or by implementing a black-start. Transition choice has major impact on the microgrid system protection and control design. In order to enable seamless islanding transition, first, it is necessary to design reliable and secure islanding detection. Traditional techniques are typically based either on local detection schemes using undervoltage (27), overvoltage (59), frequency (81O/81U), rate of change of frequency (81R) or fast rate of change of frequency (81RF) protective elements or on communications-based detection schemes, which are costly, but provide better reliability and security. Grid synchronization process is less challenging, because it is initiated by either the microgrid operator or microgrid controller.

Review of the literature shows numerous proposed methods for microgrid seamless transition. Majority of the proposed methods involve modified design of the inverter control loops in order to enable the seamless islanding and grid synchronization and control of the islanding switch. Authors in [66] propose the use of intelligent connection agent implemented in a grid-connected power converter that acts and adapts its operating mode according to its connection state and also controls the operation of point of common coupling (PCC) breaker. Authors in [67] proposed the use of DER power converters with controller that involves angle, frequency, and power loops instead of conventional current and voltage loops. The controller is based on the concept of ”synchronverter” to emulate the behavior of a synchronous generator (SG) by a virtual rotor and it operates the same way in grid-connected and islanded modes. Authors in [68] introduced the power control technique based on the compensation of reactive power demand,
harmonic currents, and load unbalance by local DG and sharing of active power demand between the microgrid and respective local DG. Authors in [69] assumed that islanding events, in most instances, can be predicted and propose an adaptive optimal defense mechanism to establish secure islanding, without acquiring fast response energy resources. Authors in [70] proposed the use of DERs operating in droop mode when grid-connected, with one DER being designated as dispatch unit that enables seamless islanding. Authors in [71] proposed the design of the multi-loop controller in the inverter control layer so that the closed-loop dynamics of the inverter, together with the LC filter, present unity gain, which fully cancels the mode transitions. Authors in [72] and [73] proposed the use of one common DC bus for all DERs, and the use of bidirectional interlinking converter (BIC) to for connection to the microgrid. In case of a grid fault, BIC is disabled, and seamless transition is enabled by the voltage regulation mode of BESS. Authors in [74] also proposed the use of DC microgrid with BIC and the islanding detection method is based on the insertion of a controllable load in parallel with the DC microgrid central switch. The addition of proportional-integral regulator as part of the central microgrid controller enables the seamless islanding and grid synchronization. Authors in [75] proposed the use of a multi-droop control strategy to mitigate voltage and frequency variations during mode transition. Authors in [76] proposed an algorithm that enables the DERs to operate in current control mode when grid connected and in droop control mode when islanded in order to achieve proportional power sharing among DERs. Authors in [77] proposed the microgrid algorithm where one of the DERs already operates in grid-forming mode when connected to the grid, without any communications to the PCC and therefore without the knowledge of the status of the PCC. Authors use voltage and frequency elements for islanding detection, which cannot be reliably used due to the existence of non-detection zones (NDZ). Authors in [78] proposed the seamless microgrid transition scheme
that consists in part of the islanding detection using the equivalent of ANSI/IEEE 78VS or vector shift element. This element cannot be reliably used to detect the islanding condition because of the NDZ. Authors in [79] also proposed the seamless islanding algorithm where one of the DERs already operates in grid-forming mode when connected to the grid. However, even though the algorithm shows the seamless islanding and grid synchronization, this approach would fail because both relay and DER protective settings that would cause the microgrid to trip within 5 cycles due to excessive overvoltages.

Majority of the proposed microgrid islanding and grid synchronization algorithms in the current literature are based on HIL-simulation or small system implemented in lab. There are four major challenges involved with the approaches proposed in the current literature.

1. Vast majority of papers involving microgrids are designed as either ungrounded systems or do not have proper microgrid grounding implemented as part of the proposed one-line diagram. In grid-connected mode, effective grounding is provided by the substation transformer. Once the islanding PCC switch opens, ground reference is lost, so a new source of ground must be provided for the microgrid. In microgrids with inverter-based DERs, grounding transformer ($Yg-\Delta$ or Zig-Zag) must be used in order to provide the effective microgrid grounding. Using proper grounding design affects the performance of the proposed algorithms and may not result in seamless islanding and grid synchronization transitions,

2. Majority of microgrid papers show the $Yg-\Delta$ DER transformer as the preferred configuration. This type of configuration provides the additional zero-sequence path for the current flow during the ground faults, and as a result, upstream relays might not trip for the ground fault. For that reason, this type of transformer configuration is not allowed on most $Yg$ distribution systems. In addition, if the DER $Yg-\Delta$ transformer provides the grounding reference for the
microgrid, it must be designed as a grounding transformer with proper short-term fault current rating, continuous unbalance rating and proper zero-sequence impedance. Typically, DER transformers are designed to enable the nominal DER output and simply implementing $Y_g$–Δ DER transformer configuration can result in microgrid overvoltages during the fault and DER transformer failure during a fault.

3. Relay settings during the transitions to and from an island are not extensively discussed in the literature. Keeping the relay settings the same during islanding or grid synchronization will result in microgrid blackout most of the time. Further, DER control loops must be designed to ensure stable operation during the operating mode changes and must not allow for the voltage and frequency to exceed the expanded relay settings during the transition.

4. Delays associated with the operation of field devices like the PCC relay or the delays in the communications channels between the controllers and field devices/relays, are often ignored in simulations. Even though a proposed algorithm can be successful in simulations and small scale lab experiments, the implementation in the field might fail due to the inherent delays that were ignored.

This section fills the gap with respect to the aforementioned shortcomings in the current literature and proposes new seamless islanding and grid synchronization schemes. The schemes were implemented in the field within the actual microgrid installed on the investor-owned electric utility’s distribution feeder. Lessons learned from designing, construction, commissioning and operation of this microgrid along with some initial algorithms were presented at [80] and [81]. However, the seamless islanding and grid synchronization algorithms have changed and improved over the time and they have been tested over the period of two years with over 9,000 successful
transitions and this section provides the new and improved protection and control schemes for seamless islanding and grid synchronization as presented in [82].

8.2. Seamless islanding

Reliable and secure islanding detection is not a focal part of this paper, but for the purposes of discussion, the implemented islanding detection scheme is based on passive detection technique that uses the local voltage (27), frequency (59), rate of change of frequency (81) and fast rate of change/fast rate of change of frequency (81R/81RF) measurements. These settings are implemented within the PCC relay and BESS inverter controller. In order to execute seamless islanding, it is necessary to understand the operating modes of different DERs and if they can be used for seamless islanding (ISO) as shown in Table 44. Machine-interfaced DERs such as a synchronous are typically designed to operate as stiff voltage sources and operate only in islanded mode (ISO). Inverter based DERs can operate both as either current or voltage sources. In current source inverter (CSI) mode the inverter has a constant but adjustable current fed from the DC source. However, the output voltage magnitude depends on the load impedance. In VSI operating mode AC output voltage is load independent, but the output current magnitude depends on the load impedance. The inverter can operate as a stiff voltage source, much like a generator (VSI-ISO). In addition, the inverter can emulate the PQ operating modes where the inverter controls the power output (P and Q) but does not effectively control voltage or frequency (VSI-PQ). The VSI-V/f or droop mode can be used as a grid forming mode, where the real power is used to control the frequency and reactive power is used to control the voltage.

<table>
<thead>
<tr>
<th>DER</th>
<th>Operating mode</th>
<th>Black start</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator</td>
<td>Baseload, &quot;droop&quot;, ISO</td>
<td>Yes</td>
</tr>
<tr>
<td>BESS</td>
<td>CSI, VSI(-PQ,-V/f,-ISO)</td>
<td>Yes</td>
</tr>
<tr>
<td>Microturbine</td>
<td>CSI, VSI-ISO</td>
<td>Yes</td>
</tr>
<tr>
<td>PV</td>
<td>CSI</td>
<td>No</td>
</tr>
</tbody>
</table>
Both frequency and voltage within the microgrid are controlled in this case based on the user defined droop curves (in the case of the microgrid considered in this paper, set-points for the BESS inverter droop mode have been chosen as $347V \pm 5\%$ and $60Hz \pm 1\%$). VSI-ISO or isochronous mode is also grid-forming mode where the inverter is set to maintain both voltage and frequency at a single point. Synchronous generators, BESS and microturbines can typically act as a voltage and frequency source, while PV cannot. Before the seamless transition algorithm is executed, it is necessary to determine which of the two DERs (generator, BESS or both) that can provide the voltage and frequency source are operational. Note that the operation of either PV or microturbine in CSI mode does not affect the seamless transition algorithm.

Generator-only islanding transition algorithm works as follows:

1. Islanding is initiated based on the microgrid controller command or PCC relay has detected the fault on the feeder,
2. PCC relay switches the protective settings group and issues PCC TRIP command,
3. Microgrid controller detects PCC status change and sends the command to generator controller to go to ISO mode (communications-based),
4. Generator changes the operating from baseload to ISO,
5. Microgrid controller detects the generator operating mode change and send the command to PCC relay to switch the settings group, and
6. Islanding transition algorithm has been completed.

Note that in this case, communications-based operating mode command change results in seamless islanding because the generator still has inertia in baseload mode, and it is capable to provide the voltage and frequency regulation during the transition that does not go outside the relay protection setpoints.
In order to implement the seamless islanding transition using BESS only, new approach has been developed that uses the 85RIO scheme based on mirror bits communications. Figure 144 shows the new relay architecture. The 85RIO scheme was implemented using the digital input (DI)/digital output (DO) module (SEL 2440 in this case) installed within BESS and installing a fiber cable between this module and PCC relay (SEL 487E in this case). The communication between the two devices is based on the Mirrored Bits® [17] which as a result has a very low latency (field measurement showed this speed to be 2ms). The DI/DO is equipped with high-speed remote I/O cards which operate within 50µs, which combined with 2ms transport latency enables the seamless transition from grid-connected to islanding mode. BESS inverter has two controllers: programmable logic unit (PLC) and power control system (PCS). PLC controller communicates to the battery controller using MODBUS protocol.

![Separation of protection and automation areas within the relay.](image)

This communication channel provides all the battery’s operational data and is used to issue commands to the battery to enable the operation of the whole system. PLC also communicates using MODBUS to the microgrid controller. The PCS controller is the part of the inverter that controls the operations of power electronics (i.e. defines the operating mode of the inverter). It can do so based on either receiving the command from PLC or based on the hard-wired inputs. PLC and PCS are connected through Ethernet and communicate using a proprietary protocol. To reduce the delays, the DI/DO module inputs and outputs are both wired into PLC and PCS.
Wiring only to PLC would increase the delay time and wiring only to PCS would prevent the PLC from knowing which mode PCS operates in, as the communication between PLC and PCS is only one way. Figure 146 shows all wired inputs and outputs between DI/DO module and BESS inverter that enables seamless transition to island and grid synchronization capability.

When the microgrid is connected to the grid, AC-coupled BESS operates in $VSI-PQ$ mode. Figure 147 shows simplified algorithm that enables the seamless islanding. The algorithm that enables the seamless transition in this case is as follows:

1. Islanding is initiated based on the microgrid controller command or PCC relay has detected the fault on the feeder,
2. PCC relay changes its protection settings group (i.e. torque-control) in order to ride through the transition,
3. PCC relay issues CLOSE command to the breaker (Way 3) to energize the grounding transformer,
4. PCC relay sends the TRIP command to PCC and sends ISLAND command to both PLC and PCS within BESS inverter by closing OUT302 and OUT306,
5. BESS inverter switches the operating mode from VSI-PQ to VSI-V/f with ±5% voltage and ±1% frequency droop settings,
6. When PCC breaker opens, PCC relay receives the state change,
7. PCC relay sends the change of state message to both PLC and PCS within BESS inverter by closing OUT301 and OUT305,
8. Upon receiving PCC status change, PCS changes the operating mode from VSI-V/f to VSI-ISO;
9. When BESS inverter has switched to VSI-ISO operating mode, PCC relay switches again the protection settings group,
10. Islanding transition algorithms has been completed.

Figure 147. Seamless islanding transition – algorithm.

Unintentional islanding follows the same algorithm as intentional islanding. If the unintentional islanding is caused by an upstream fault, there is a ”race” between the PCC relay
and BESS inverter PLC to detect the fault, using undervoltage (27) overvoltage (59) frequency (81U/81O) and rate of fast rate of change of frequency (81R/81RF) settings. If the PCC protection and controls senses the fault/disturbance first, then the procedure is the same as intentional islanding; if the BESS inverter senses the fault/disturbance first, the PCS closes IN204 in DI/DO device and it changes the operating mode to VSI-V/f. The PCC relay sees IN204 go high, which initiates PCC open command. The only difference here is that the grounding transformer is connected to the microgrid in islanded mode after rather before the PCC opens. This is important since otherwise the PCC could be exposed to overvoltages in excess of its withstand rating. Simulations show these voltages reach 70kV levels, for a 15kV PCC that has 45kV wet and 50kV dry withstand voltage rating. From here, the algorithm is the same as for intentional islanding.

One challenge with this scheme is its reliability and security when DI/DO device loses power or when there is a loss of communications, both of which render the 85RIO scheme unusable. Loss of power of DI/DO device is detected by wiring the ALM contact to one of the digital inputs on the BESS inverter PLC. Both PLC relay and DI/DO device continuously send and receive digital logic messages and monitor their integrity. If there is a loss of communications or if there are any bad messages transmitted, both devices will create an loss of communications alarm.

For redundancy an additional path was established between the microgrid controller and BESS inverter PLC. In case that 85RIO scheme is disabled for any reason and there is a fault on the feeder, the BESS inverter PLC will detect the fault based on its own protection settings and it will switch from VSI − PQ to VSI − V/f mode. At that time, the microgrid controller, which has the PCC status point available, will send the PCC status change from CLOSED to OPEN to the BESS inverter PLC. From there, the BESS inverter PLC will send this information to the BESS
inverter PCS using ethernet connection. Upon receiving the PCC change signal, BESS inverter PCS will switch the operating mode to VSI-ISO. Any status point change within the microgrid is generally reported to the microgrid controller using exception based reporting. Upon the change of status point, there is a delay that, depending on the type of device used can be up to 500ms based on the field testing. In addition, the network was built with microgrid polling and sending the data every second, so maximum delay of 5 seconds was chosen within which the microgrid controller must send the PCC status change message to BESS inverter PLC. In case that BESS inverter PLC does not receive the status change message within this time period of 5 seconds, it will revert to the grid-connected VSI-PQ mode.

Generator and BESS islanding algorithm is based on the design engineer preference of the BESS and generator operating modes based on the Table 45. Depending on the preferred operating mode, the algorithm for this case is based on the combination of two algorithms explained above. During the seamless transition to island it is necessary to change the protection settings group (namely voltage and frequency settings), because BESS changes three operating modes within the short period of time (128ms in this case).

Table 45. BESS and Generator Islanding Operating Modes

<table>
<thead>
<tr>
<th>BESS</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>VSI-ISO</td>
<td>droop</td>
</tr>
<tr>
<td>VSI-V/f</td>
<td>droop</td>
</tr>
<tr>
<td>VSI-V/f</td>
<td>ISO</td>
</tr>
<tr>
<td>VSI-PQ</td>
<td>ISO</td>
</tr>
<tr>
<td>CSI-PQ</td>
<td>ISO</td>
</tr>
</tbody>
</table>

Not changing the relay settings group during transition will result in microgrid black-out. Once the transition is completed, protection settings group should be changed again in order to reflect the microgrid settings in islanded mode; in this case, overcurrent settings might also change.
There are five distinct time instances before, during and after the transition that require analysis in order to ensure the success of the seamless islanding:

1. Grid connected steady-state mode – in this mode, PCC is CLOSED and DERs operate based on the user-defined mode,
2. Islanding initiation: transition to island initiates the change in BESS operating mode,
3. PCC OPEN status - PCC relay has detected that the PCC has transitioned fully from CLOSED to OPEN state,
4. Grounding transformer energization - enables the connection of grounding transformer to the microgrid. Given that BESS and PV are ungrounded, grounding transformer is necessary because it provides the solid ground reference for the microgrid, enables the grid synchronization, prevents ferroresonance from occurring within the microgrid and reduces the overvoltage resulting from open phase conditions, and
5. Steady-state island mode: this is steady state mode when BESS is the main voltage and frequency source.

8.2.1. Frequency during seamless islanding transition

This section describes the engineering design behind the frequency settings during the seamless transition to island. In grid connected mode, DER inverter settings are typically based on [43]. These settings must be carefully evaluated and calculated during each of the five intervals during seamless transition. Figure 148 below shows simulation results for the microgrid frequency response during seamless transition to island for all five time instances. As seen from the graph, keeping the frequency settings throughout the whole islanding transition the same can cause the microgrid to lose power, because of the relay tripping on underfrequency/overfrequency.
Figure 148. Frequency response during transition to island for $P_I/P_O < 1$.

Five modes defined in the previous section are described in this paragraph:

1. **Grid connected steady-state mode**: for this case, 81U/81O settings are based on typical settings that could be found in relays installed on distribution feeders as shown in Table 46.

   Table 46. 81U/81O settings for grid connected mode

<table>
<thead>
<tr>
<th>Protection element</th>
<th>Setting [Hz]</th>
<th>$t_0$ [cycles]</th>
</tr>
</thead>
<tbody>
<tr>
<td>81D1P</td>
<td>59.3</td>
<td>5</td>
</tr>
<tr>
<td>81D2P</td>
<td>60.5</td>
<td>5</td>
</tr>
</tbody>
</table>

   This area is shown on Figure 148 from [0-2] seconds.

2. **Islanding initiation**: at time $t=2$ seconds, islanding is initiated and frequency changes as the ratio between the load and generation within the microgrid. If there is less generation than the load, the frequency will decrease, and if there is excess of generation, the frequency will increase. The moment that the islanding transition is initiated, BESS changes the operating mode from $VSIPQ$ to $VSI-V/f$. Figure 149 shows the actual microgrid frequency response during several seamless transitions to island (as recorded by the PCC relay using synchophasor measurements based on IEEE C37.118 standard). Frequency set-points must be changed during this transition, because keeping the same settings as in grid connected mode will cause the microgrid to lose power.
Figure 149. Actual microgrid frequency response during transition to island.

As seen from Figure 146, in three instances, frequency goes outside the grid connected mode limits. New 81U/81O and time delay set-points are in this case defined based on the [43] as shown in Table 47.

<table>
<thead>
<tr>
<th>Protection element</th>
<th>Setting [Hz]</th>
<th>$t_D$ [cycles]</th>
</tr>
</thead>
<tbody>
<tr>
<td>81D2P</td>
<td>58.5</td>
<td>300</td>
</tr>
<tr>
<td>81D3P</td>
<td>57.0</td>
<td>10</td>
</tr>
<tr>
<td>81D5P</td>
<td>61.0</td>
<td>300</td>
</tr>
<tr>
<td>81D6P</td>
<td>62.0</td>
<td>10</td>
</tr>
</tbody>
</table>

3. **PCC OPEN status**: when PCC relay receives the command to open, this information is sent to BESS inverter PLC and PCS, and at this point, the inverter is the main source of voltage and frequency with set-point of $f = 60\text{Hz}$ and $V = 1\text{p.u.}$. Typically, this transition is completed within 8 cycles (or 128 milliseconds) from the moment that the transition is initiated. Most of this time is associated with PCC changing its state (from CLOSED to OPEN), which can take form 4-6 cycles. In this case, frequency settings are still as outlined in Table 48.

4. **Grounding transformer energization**: this operation is done couple of ways depending on the cause of islanding. If islanding command is issued by the microgrid controller, then grounding transformer is energized prior to opening of the PCC. If grounding transformer scheme is designed to energize this transformer after the PCC opens, and the microgrid
experiences a ground fault after PCC opens, but before the grounding transformer is energized (i.e. in this case, the microgrid is ungrounded), PCC would be subject to a huge overvoltage withstand, that would exceed its nominal rating. If the islanding is caused by the fault on the grid, the grounding transformer is connected after PCC opens, because in this case, there is no overvoltage withstand issue, since the feeder is deenergized. However, energizing any transformer causes huge current inrush, so majority of the impact in this case is on voltage. Frequency settings are still as outlined in Table 47, because BESS has limited capacity, and higher kVAR requirement for voltage regulation leaves less kW for frequency regulation.

5. **Steady-state island mode**: after the islanding transition has been completed, the microgrid reaches the steady state and frequency settings are set to the same values as in the grid connected steady-state mode. Figure 150 shows the summary of the frequency settings based on the analysis outlined above.

8.2.2. **Voltage during seamless islanding transition**

This subsection discusses the voltage transient during an islanding event. Five operating modes, as described before are described below: grid connected steady-state mode, islanding initiation, PCC open status, grounding transformer energization and steady-state island mode.
Figure 150. Frequency settings during transition to island.

1. **Grid connected steady-state mode**: Both undervoltage (27) and overvoltage (59) settings are based on typical settings that could be found in relays installed on distribution feeders as outlined in Table 48.

   Table 48. 27/59 settings for grid connected mode
   
<table>
<thead>
<tr>
<th>Protection element</th>
<th>Setting [p.u.]</th>
<th>$t_D$ [cycles]</th>
</tr>
</thead>
<tbody>
<tr>
<td>27P1P</td>
<td>0.88</td>
<td>120</td>
</tr>
<tr>
<td>27P2P</td>
<td>0.50</td>
<td>5</td>
</tr>
<tr>
<td>27P3P</td>
<td>0.10</td>
<td>0</td>
</tr>
<tr>
<td>59P1P</td>
<td>1.10</td>
<td>120</td>
</tr>
<tr>
<td>27P2P</td>
<td>1.20</td>
<td>5</td>
</tr>
</tbody>
</table>

2. **Islanding initiation**: Voltage settings change according to the settings in Table 49 where first level of 27 and 59 settings is modified during the transition to extend the time-delay from 120 cycles to 300 cycles.

   Table 49. 27/59 settings for transition mode
   
<table>
<thead>
<tr>
<th>Protection element</th>
<th>Setting [p.u.]</th>
<th>$t_D$ [cycles]</th>
</tr>
</thead>
<tbody>
<tr>
<td>27P1P</td>
<td>0.88</td>
<td>300</td>
</tr>
<tr>
<td>27P2P</td>
<td>0.50</td>
<td>5</td>
</tr>
<tr>
<td>27P3P</td>
<td>0.10</td>
<td>0</td>
</tr>
<tr>
<td>59P1P</td>
<td>1.10</td>
<td>300</td>
</tr>
<tr>
<td>27P2P</td>
<td>1.20</td>
<td>5</td>
</tr>
</tbody>
</table>
Even though 300 cycles could potentially be extended, majority of the transients within the microgrid dissipate within the first 120 cycles.

3. **PCC OPEN status**: when PCC relay receives the change in PCC status to open, BESS inverter has a voltage setpoint at 1.0p.u. Settings in this case are the same as in Table 49.

4. **Grounding transformer energization**: majority of voltage variations during the transition to island occur during the grounding transformer energization. Figure 150 shows the results of the MATLAB/Simulink simulation of microgrid voltage response caused by the grounding transformer energization during several successive seamless islanding operations. As seen from the figure, microgrid experiences significant voltage sags that can have potentially negative effect on its ability to reliably transition to an island. These voltage sags occur because BESS must provide reactive power for the large grounding transformer inrush current.

![Figure 151. Voltage during successive transition to island.](image-url)

Voltage sag in this case is a function of the grounding transformer residual magnetism as well as the time on the voltage sinusoid when the breaker that energizes the grounding transformer is closed.
As seen from this figure, voltage sag can be in [47-95]% range, which can easily trip the microgrid. Without disabling the first level of 27/59 settings, microgrid relay would trip the breakers causing the outage within. Upon the seamless connection to the grid, grounding transformer is de-energized. Due to the random time of the grounding transformer de-energization, its residual magnetism has a random value, so any successive grounding transformer energization will result in random voltage sag level. Figure 151 shows the actual voltage sags during the transition to island for several successive operations.

![Image](image.png)

Figure 152. Voltage during successive transition to island – actual.

As seen from this figure, voltage sag is in [4-47]% range. The reason for different voltage sags is because three-phase gang-operated breaker, closing at random angle on voltage sinusoid with random residual magnetism within grounding transformer will result in different voltage sags. Figure 152 shows the voltage sag magnitude, duration and neutral current during one such event. Based on the lessons learned from this field implementation, three transformer inrush current mitigation solutions were installed at the microgrid site, which significantly reduced the inrush current and voltage sag. As a result of the implementation, the voltage sags have been limited to no more than 10%. 

206
5. **Steady-state island mode**: after the islanding transition has been completed, the microgrid reaches the steady state, and voltage settings are changed to the same level as grid connected steady-state mode as outlined in Table 48. Figure 154 shows the summary of the voltage settings based on the analysis outlined above.

Figure 153. Voltage and neutral current during grounding transformer energization.

Figure 154. Voltage settings during transition to island.
8.2.3. Islanding detection as a function of $P_L/P_G$ ratios

One of the most challenging tasks regarding microgrid islanding detection is the security and reliability of the control scheme in cases when $P_L/P_G = 1$. Proposed control scheme and algorithm for the seamless islanding have been tested at the electric utility’s microgrid for the ratio of $0 < P_L/P_G < 2$. Figure 155 shows the response of different relay protection elements (27,59,81,81R) for both PCC and BESS inverter PLC during fault conditions and how they compare to the traditional and SEL islanding detection schemes [83] based on the local measurements. Based on the results, the following conclusions can be made:

1. The proposed islanding detection scheme using the local settings combined with 85RIO scheme that enables the seamless transition is much faster than currently available alternative schemes (traditional, SEL),

2. 81R element provides the fastest islanding detection response,

3. The proposed scheme works for $P_L/P_G = 1$ field conditions (this transition was tested around 30 times in the field); subsequent simulations and tests proved that if the reactive power difference is more than 1% of the microgrid total capacity, then is islanding under $P_L/P_G = 1$ condition is successful,

4. For $P_L/P_G < 0.2$ field operating condition, when generation significantly exceeds the load, the microgrid trips due to Load Rejection Over-Voltage (LROV); this is known effect because when PCC opens, the voltage measured within the microgrid was between 144V - 164V, which will cause the microgrid to trip immediately on the overvoltage condition (second level overvoltage setting is 1.2p.u. or 144V at 5 cycles).

Note that in all cases tested in the field, there was enough generation to supply all the load. For that reason, the microgrid transitions never resulted in a black-out. However, many microgrids
might not have enough generation to support the load within and in order to enable the seamless transition it is necessary to shed the load. This feature was also implemented within the microgrid using 85RIO scheme.

The microgrid controller algorithm calculates if there is enough internal generation to support the microgrid load. If $P_G < P_L$ at the moment when the islanding is initiated, the microgrid controller will issue load shedding command to the breaker that carries non-essential load (in this case, for the purposes of field testing, load bank was used as non-essential load). Graph below shows the delays associated with each part of the 85RIO load shedding scheme. As seen from the graph, the communication delay associated with fiber optics mirror bit data transfer is 2-4ms. Following, breaker relay has a 50µs time delay associated with its contact closure. Finally, breaker trip coil has a maximum 35ms operating time, which amounts to the total delay time for load shedding scheme under 40ms.

Figure 157 shows simplified algorithm that enables the seamless grid synchronization algorithm. The algorithm that enables the seamless grid synchronization is as follows:
Figure 156. Load shedding scheme - communication delays.

1. Initiate grid synchronization sequence - this is done from microgrid controller or based on the user input (from HMI),

2. Microgrid controller checks for stable grid voltage condition within PCC relay,

3. If voltage is above the minimum healthy voltage level of 0.9p.u., the algorithm proceeds to step 3; if voltage is below the 0.9p.u., then the microgrid controller waits until the voltage has been healthy for 5 minutes and continue with step 4,

4. Microgrid controller sends the command to PCC relay to change the protection settings group and sends the command to the BESS inverter to start the grid synchronization procedure,

5. BESS inverter first switches its operating mode to VSIV/F mode after it receives the grid synchronization command from microgrid controller, and starts synchronizing voltage magnitude, voltage angle and frequency to the grid value,

6. After the synchronization process is completed, BESS inverter sends the grid synchronization completed status to PCC relay through DI/DO device enabling IN205,

7. PCC relay also checks for synchronization settings (25) to be within the user-defined limits, closes the PCC breaker and disconnects the grounding transformer,
8. Once PCC relay has confirmation that the PCC has closed; OUT301 and OUT305 in DI/DO device that is part of 85RIO scheme become high, so the BESS inverter changes its operating mode to **VSI-PQ**.

9. The microgrid relay enables the grid steady-state voltage and frequency settings,

10. Grid synchronization process has completed.

![Figure 157. Seamless grid synchronization – algorithm.](image)

### 8.3. Seamless grid synchronization

During the seamless transition to grid both voltage and frequency change their values, and in order to make a successful transition, both voltage and frequency settings must be properly implemented.

#### 8.3.1. Frequency during seamless grid synchronization

Figure 158 shows the frequency field response during grid synchronization process. There are three intervals during grid synchronization process that the microgrid goes through (note that the microgrid operates in steady-state island mode at this time):

1. **Grid synchronization initiation**: once microgrid controller issues command to BESS inverter to start grid synchronization process, BESS inverter first switches its operating mode from VSI-ISO to VSI-V/f, where frequency can vary between (60±1%)Hz to match the frequency of the grid. As seen from Figure 158, during one such transition, frequency reaches 60.62Hz for 25 cycles before the BESS inverter can stabilize and match the frequency of the microgrid.
to 60Hz, which represents the grid frequency reference value. For this reason, during this transient period frequency settings must be changed to the ones from Table 47; otherwise, the microgrid would trip on the 81O setting - 60.5Hz at 5 cycles.

Figure 158. Frequency response during grid synchronization.

1. **PCC CLOSED status**: once grid synchronization is completed, and microgrid has been connected to the grid (microgrid controller receives PCC CLOSED status), the frequency settings must change to the grid connected steady-state values as outlined in Table 46.

2. **Grounding transformer de-energization**: this has no effect on frequency settings. Figure 159 shows the summary of the frequency settings based on the analysis outlined above.

### 8.3.2 Voltage during seamless grid synchronization

This section describes the engineering design behind the voltage settings during the seamless transition to grid. Figure 160 shows the voltage field response during grid synchronization process.

1. **Grid synchronization initiation**: once microgrid controller issues command to BESS inverter to start grid synchronization process, BESS inverter first switches its operating mode from VSI-ISO to VSI-V/f.
Figure 159. Frequency settings during transition to grid.

Figure 160. Voltage settings during transition to grid.
This, as a result, changes the voltage set-point operating range within BESS to [0.95-1.05]p.u. This is necessary because BESS inverter needs to match the voltage of the grid, so it needs to operate in a range. Due to different control loops associated with these two modes, voltage response changes, but this change is not as severe as frequency change. As seen from Figure 161, once grid synchronization mode is initiated, voltage goes from 1.03p.u. to 1.04p.u. which represents small change.

![Figure 161. Voltage response during transition to grid.](image)

Since changes could potentially be more severe during the transient period, voltage settings must be changed to the ones from Table 49.

2. **PCC CLOSED status**: once grid synchronization is completed, and microgrid has been connected to the grid (microgrid controller receives PCC CLOSED status), voltage settings must change to the grid connected steady state values as outlined in Table 48.

3. **Grounding transformer de-energization**: upon connecting back to the grid, grounding transformer must be disconnected from the system. Note that this change does not affect any voltage settings, because grounding transformer (which has no load) in steady-state has very low reactive current and disconnecting this transformer will cause small reactive current change, but no voltage change. Even though grounding transformer is connected to the
microgrid after PCC opens, going back to the grid, grounding transformer must be disconnected after PCC closes. Disconnecting the grounding transformer prior to connecting to the grid will cause the loss of ground reference within the microgrid, and PCC relay will block the closing of PCC because the synch-check measurements on the microgrid side for voltage, frequency and voltage angle in such case do not have a solid ground reference point.

8.4. Conclusion – seamless islanding and grid synchronization

This section introduces the new 85RIO communications-based microgrid seamless transition scheme. All control schemes as described in this paper have been simulated and implemented within the actual electric utility’s microgrid. The algorithms have been thoroughly tested, and during the period of 24 months, approximately 9,000 successful seamless transitions have been completed within the microgrid, proving that schemes work. The additional research in this area should be focused on adding large motor loads to the microgrid and understanding the impact of starting of this motor and the voltage and frequency response from inverter-based V/f source (like BESS).
CHAPTER 9: Conclusions and Future Research

Based on the research as described in this document, there are several contributions that further advance the implementation of system protection and control techniques within the microgrid. All the proposed methodologies and algorithms in this research have been thoroughly simulated and all concepts presented in this research have been implemented and tested on the actual electric utility’s microgrid. The most important contributions of this research paper are:

1. Implementation of the proper DER transformer winding configurations within the microgrid,
2. New methodology for the design and implementation of grounding transformer,
3. New microgrid system protection methodology for grounding transformer,
4. Three new protection and control schemes for microgrid with inverter-based DERs, and
5. New microgrid controls algorithm for seamless islanding and grid re-synchronization.

As a result from the research and actual design, installation, commissioning, implementation and operation of the proposed microgrid system, numerous papers have been published in magazines, and the author has presented the material at several IEEE and electric industry conferences and held several webinars on the topics of the research. Following is the list of presentations and technical papers that have been either accepted or presented based on the research and field implementation presented in this research document:

1. “Microgrid Protection and Control Schemes for Seamless Transition to Island and Grid Synchronization“ – IEEE Transactions on Smart Grid, 2020,
2. IEEE Transactions of Power Delivery – reviewer,
3. “Protection and Control for Microgrid with Inverter-based Distributed Energy Resources (DERs) Using Voltage-restrained Overcurrent element (51VR) and Rate of Change of
Current sequence Components ($\Delta I_{1,2,0}/\Delta t$) - Part I” - IEEE Transactions on Power Delivery (in review), 2020,

4. “Protection and Control for Microgrid with Inverter-based Distributed Energy Resources (DERs) Using Voltage-restrained Overcurrent element (51VR) and Rate of Change of Current sequence Components ($\Delta I_{1,2,0}/\Delta t$) - Part II” - IEEE Transactions on Power Delivery (in review), 2020,

5. “Design and Implementation of Protection and Control Scheme for Grounding Transformer Installed Inside the Microgrid With Inverter-based Distributed Energy Resources (DERs) - Part I” - IEEE Transactions on Power Delivery (in review), 2020,

6. “Design and Implementation of Protection and Control Scheme for Grounding Transformer Installed Inside the Microgrid With Inverter-based Distributed Energy Resources (DERs) - Part II” - IEEE Transactions on Power Delivery (in review), 2020,


12. “Lessons Learned from Microgrid Implementation at Electric Utility” – IEEE PES YP Webinar (2 hours),


15. “Lessons Learned from Implementation of Microgrid Islanding Detection Schemes Based on Rate of Change of Frequency (ROCOF) and Synchrophasor Measurements” - 73rd Protection and Controls Conference at Georgia Tech – 2019.
REFERENCES


219


L. Stahler, "Grounding banks - determining the required capacity," in *Fall Conference - Engineering Operation Section, Southeastern Electric Exchange*, 1943, Birmingham, AL.


ANSI C84.1-2016, "American national standard for electric power systems and equipment—voltage ratings (60 Hz)," pp. 1-21, October 2016.


[50] H. Sharaf, H. Zeineldin and E. E. El-Saadany, "Protection coordination for microgrids with grid-connected and islanded capabilities using communication assisted dual setting
directional overcurrent relays," *IEEE Transactions on Smart Grid*, vol. 9, no. 1, pp. 143-151, Jan 2018.


[105] "IEC 60044-1 Standard: Instrument Transformers".


IEC 61000-4-30: 2015 Electromagnetic compatibility (EMC) - Part 4-30: Testing and measurement techniques - Power quality measurement methods.


IEC 61000-3-7: 2008 Electromagnetic compatibility (EMC) - Part 3-7: Limits - Assessment of emission limits for the connection of fluctuating installations to MV, HV, and EHV power systems.


UL 1741. Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources.


