Ride Through Testing Equivalence Study

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Record of Amendments

Date	Section	Amendment
12 Jul 21	All	New document generated
28 Oct 21	All	Released for peer-review
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6 Oct 22	E, F	Removal of SME Comments

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1. Introduction

OneStep Power Solutions Inc. has developed a range of technologies to safely prove the ride through capability of vessels as a result of a three-phase symmetrical short circuit. These technologies, when combined with industry-accepted best practices and a robust commissioning, sea trials and DP FMEA process, provides demonstrable evidence of a vessel's closed bus equivalent integrity. That is, the facility's closed bus operations may be considered as safe or safer than the same facility operating with open bus-ties.

Explanations of open bus and closed bus, and the necessity for demonstrating equivalent integrity are not the subject of this white paper. For these topics, please refer to IMO Circ 1580[1] as the primary source document, with many high quality class and industry guidelines available for how to implement.

It is OneStep Power's expectation that this White Paper will provide sufficient information to provide experts in dynamically positioned vessel power systems with the ability to form the conclusion that OneStep Power's Equivalent Integrity Protocol provides at least as much evidence of a vessel's capability to ride through network disturbances associated with short circuits as performing a live short circuit.

It should be noted that the use of the word network throughout this document is in reference to a power generation and distribution network, as is standard in the power engineering community, and not a control or communications network unless otherwise stated.

[1] International Maritime Organisation (2017) MSC.1/Circ.1580 Guidelines for Vessels and Units with Dynamic Positioning (DP) Systems. Accessed 26 October 2021 https://www.register-iri.com/wp-content/uploads/MSC.1-Circ.1580.pdf

2. OneStep Power Solutions Inc.

OneStep Power provides testing and engineering solutions for companies within the offshore dynamic positioning sector. OneStep Power is dedicated to providing high-quality testing systems and solutions to maximize customer satisfaction.

Robust

OneStep Power offers comprehensive system testing and engineering packages designed to comply with class and industry best practice.

Reliable

These solutions are peer-reviewed prior to implementation with a view to completeness, efficiency and compliance.

Repeatable

OneStep Power provides comprehensive programs and utilizes a detailed record keeping and lessons learnt process to ensure testing protocols are maintained for continuity. Our test systems provide a consistent test and a predictable outcome.

At OneStep Power, we believe that the offshore industry is long overdue for a change in the methods and expectations for power system testing and we are dedicated to bringing the industry into a new era of engineered solutions and reliable outcomes.

OneStep Power is a Delaware Corporation.

What to Expect

- Knowledgeable & professional team
- Clear and definitive pass/fail criteria
- Safe testing solutions
- Support for remedial action if needed

3. Acronyms

Acronym	Definition
ABB	Formerly ASEA Brown Boveri (Company Name)
ABS	American Bureau of Shipping (Company Name)
AC	Alternating Current
AVR	Automatic Voltage Regulator
CT	Current Transformer
DC	Direct Current
DNV	Formerly Det Norske Veritas (Company Name)
DP	Dynamically Positioned or Dynamic Positioning
DQ	Direct and Quadrature
E_A	Internal amature voltage
FMEA	Failure Mode & Effects Analysis
FRT	Fault Ride Through
GVRT	Generator Voltage Response Tester
HV	High Voltage
IMCA	International Marine Contractors Association (Organisation Name)
IMO	International Maritime Organisation (Organisation Name)
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
I_n	Nominal Current
I_r	Rotor Current
IT	Isolated Terra (Earthing System)
MTS	Marine Technology Society (Organisation Name)
NGR	Neutral Grounding Resistor
OEL	Over-excitation Limiter

OEM	Original Equipment Manufacturer
OTP	Onsite Test Plan
PC	Personal Computer
PID	Proportional–Integral–Derivative
PT	Potential Transformer (also known as voltage transformer)
PWM	Pulse Width Modulation
RCoil	Rogowski Coil
RFI	Requires Further Investigation
RL	Resistive-Inductive
RMS	Root Mean square
SCR	Silicon Controlled Rectifiers
THD	Total Harmonic Distortion
UEL	Under-excitation Limiter
USB	Universal Serial Bus
USCG	United States Coast Guard
VAR	Volts-Ampere-Reactive (Reactive Power)
VT	Voltage Transformer
VDRT	Voltage Dip Ride Through
WCFDI	Worst Case Failure Design Intent
ZVRT	Zero Volts Ride Through

4. Definitions

OneStep Power uses a few terms for specific tests:

- Voltage Dip Ride Through (VDRT): Transient under-voltage and over-voltage test which can be applied to the entire facility using OneStep Power's "Generator Voltage Response Tester" (GVRT)
- Zero Volts Ride Through (ZVRT): Controllable zero-voltage test which can be applied to a single bus or combination of buses using OneStep Power's ZeroDip.
- Fault Ride Through (VDRT + ZVRT): Test to produce zero-volts and transient over-voltage waveform on a bus or combination of buses using both GVRT and ZeroDip simultaneously.

All three tests, their method, expected outcomes and acceptance criteria are described in this document.

5. OneStep Power's Equivalent Integrity Protocol

Traditionally dynamic positioning vessels have operated in open bus configurations which reduces fault propagation paths between redundancy groups and subsequently reduces the risk of losing position. Modern strengthening of environmental and emissions standards have prompted vessel operators to move to closed bus configurations. While beneficial, closed bus configurations can lead to loss of DP capability if the power system is unable to ride through certain faults.

The industry standard solution is the use of live short circuit tests to prove fault ride through capability during closed bus operations. However there is also commentary regarding the danger, difficulty, and potential damage that such testing involves. Live short circuit testing is only possible on some systems due to the fault currents associated with this test, and in many situations are not suitable for the vessel design. This has resulted in a broad range of regulatory and charterer requirements which generally allow alternative methods to be considered.

Since incorporation, OneStep Power has encouraged the dynamic positioning sector to consider power system testing holistically. OneStep Power has developed tools to fill the missing gaps in the industry, not to replace existing best practices. Some of these practices are included in what OneStep Power refers to as an Equivalent Integrity Protocol.

OneStep Power's Equivalent Integrity Protocol is a full testing package which, when completed, provides assurance of a vessel's equivalent integrity for closed bus operations. While OneStep Power will contract vessels for only our fault ride through testing, this is not our endorsement of a facility's equivalent integrity for closed bus operations, which should be generated by a competent marine assurance professional, or other specialist with access to the information presented from an Equivalent Integrity Protocol or separate testing packages.

If OneStep Power is provided with sufficient data-centric evidence to support the Equivalent Integrity Protocol, a statement of equivalent integrity may be produced. We do not require re-testing if available information is sufficient for a qualified professional to reach the same conclusion. OneStep Power's Equivalent Integrity Protocol has the following minimum requirements that will be described in greater detail in the following subsections:

1. Protection setting audit (inc. version control)
2. Fuelling Testing
3. Excitation Testing
4. Over-Voltage Testing
5. Earth Fault Testing
6. Relay & Protective Device Testing
7. Current Sensing Testing
8. Load application & Rejection Testing
9. Phase Failure Testing
10. Blackout Recovery Testing
11. Harmonic Distortion Testing
12. Fault Ride Through Testing for voltage transients ***GVRT + ZERODIP***

Where additional testing has been considered as part of a comprehensive testing package and not been included in the Equivalent Integrity Protocol, these tests are described in Appendix C.

Before any testing can be started a full and complete understanding of the vessel's power system and protections is required. To attain this knowledge OneStep Power undertakes an engineering study to review all documentation to develop a vessel specific Onsite Test Plan.

5.1. Protection Settings Audit

Prior to commencing testing a review of the system settings should be completed and presented to the testing provider. Ideally, this should be performed in advance of testing personnel/equipment mobilisation to site so that any identified issues can be reviewed and corrected with appropriate revision control and management of change prior to commencing the testing program. The person tasked with gathering the data from the protection systems should have knowledge of the methods and protocols for retrieving this information, which may not be a member of the ship's crew, but does not need to be a third party.

A review of the audit by sample-checking should be performed by the testing personnel prior to commencing testing to confirm the revisions and settings match the provided audit documentation.

Test programs should be developed to perform testing without changing protection settings. Where protection settings must be disabled or changed for a testing program, these should be noted, and a final, comprehensive audit of protection settings be performed to ensure a return of all settings prior to the vessel returning to service.

All OneStep Power testing protocols can be performed without changing protection settings.

5.2. Fuelling Failure

In a system with multiple generators, a fueling fault could result in one or more generators producing more or less power than required. A simple way to illustrate this is with the equation:

$$\text{Active Power}_{\text{Output}} \neq \text{Active Power}_{\text{Requested}}$$

There are a number of failures that can lead to this outcome which will not be discussed in this document as the cause of the failure is immaterial; there are three possible results to fuelling failures, which are described below.

5.2.1. Underfuel

In the case where an engine connected to the bus experienced an underfueling event, it would result in the affected machines producing less kW than the other machines online, resulting in a load imbalance.

The load imbalance may be followed by a reverse power fault if the fuel injected into the engine is reduced to a point that the engine no longer drives the generator, causing the generator to consume power, and act as a motor.

5.2.2. Overfuel

In the case where an engine connected to the bus experienced an overfuel event, the affected machine would produce more active power than required. This would cause the other machines online to produce less kW, resulting in a load imbalance. If the fault was severe enough, other online generators can be pushed into reverse power.

Overfuel events may result in an overfrequency if the injected fuel is increased to the point of affecting bus frequency. The mechanism for this will depend on the engine load sharing configuration (droop or isochronous). Operational configurations should be validated.

5.2.3. Unstable fuel control

An unstable fuel controller should generate alarms due to kW imbalance and cause a standby engine to start. If the controller becomes too unstable, the generator should either enter reverse power, push the healthy generators into reverse power or trip the faulty unit’s circuit breaker on overload or overcurrent. In addition to the faults listed, an unstable fuel controller may result in varying frequency, power and voltage making it difficult, if not impossible, for a healthy generator set to synchronize and connect to the bus.

5.2.4. Testing for the Worst Case Failure

The worst case failure associated with fuelling failures is the loss of healthy generator(s) and subsequent loss of the unhealthy generator resulting in loss of power. From a detection perspective, the worst case is where two generators are online and the healthy generators cannot “vote” the unhealthy generator off: protection systems for fuel control faults that are based solely on voting on the operating points of generators cannot reliably detect the faulty generator when there are only two generators operating in parallel.

If the facility is intending to perform dynamic positioning operations with 2 generators (including 1 generator + battery configurations), fuelling tests should be performed in the two-generator configuration as well as the base operating configurations.

5.2.5. How to test for Fuelling Failures

Fuel system failure testing is generally performed as part of the DP FMEA program, and, provided a data-centric evidence-based approach to data collection was used, this data may be used in the OneStep Power assessment of equivalent integrity. If the data is insufficient to provide evidence of the vessel's capability, OneStep Power can assist with performing this testing in conjunction with the engine or governor OEM.

The rate at which the generator acquires load may be important to the selection of protections and both rapid and slow fuelling faults should be included during validation.

This test is performed by varying the governor position of a single generator while the generator is online with other generators. If the system is designed to run with only two generators (or 1 generator and battery), a test should be performed with two generators online, and a fuel fault induced on one of the online generators. The adjustments to the governor should be made by use of an appropriate mechanism that will not cause damage to the fuel delivery or fuel control system. Most engine and governor control vendors have an acceptable method for inducing this style of fault as it is a standard FMEA and regulatory compliance test.

Acceptance criteria:

- Correct identification of faulty unit
- Correct discrimination by isolating either the faulty engine or the bus to which the engine is connected.

Note: if the protections are holistically verified, the generator can be isolated first, rather than the bus. This allows for reduction of the disturbance to the smallest possible failure effect.

5.3. Excitation Failure

Excitation control failure in a multiple generator system may be simplified as:

$$\text{Reactive Power}_{\text{Output}} \neq \text{Reactive Power}_{\text{Request}}$$

While there are many failure modes which would result in excitation control anomalies, there are only three possible mechanisms:

- Over-excitation events resulting in either a VAR imbalance, or system over-voltage.
- Under-excitation events resulting in either a VAR imbalance or system under-voltage.
- Unstable excitation

Examples of faults include:

- Loss of sensing
- Loss of field
- Faulty rotating diodes
- Loss of Automatic Voltage Regulator (AVR) control

5.3.1. Over-excitation

In the case where a generator connected to the bus experiences an over-excitation event, the affected machine produces more reactive power than required. This would cause the other machines online to produce less kVAR, resulting in a reactive load imbalance, which results in an uneven power factor distribution across all machines connected to the bus. If the fault was severe enough, other generators online could be pushed off-line on reverse reactive power. This would leave the affected machine alone on the bus, and increase bus voltage to the level of over-voltage trip, resulting in blackout. In addition, the affected machine may experience overheating of the exciter field windings and generator rotor due to increased strength of the magnetic field.

5.3.2. Under-excitation

In the case where a generator connected to the bus experiences an under-excitation event, the affected machine produces less reactive power than required. This would cause the other machines online to produce more kVAR, resulting in a reactive load imbalance, which leads to uneven power factor distribution across all machines connected to the bus. If the fault was severe enough, the affected machine may trip on reverse reactive power, the remaining machines on the bus will experience instantaneous increased terminal voltage that may cause critical equipment to trip on over-voltage. In addition, the ‘healthy’ machine(s) may experience overheating of the exciter field windings and generator rotor due to increased strength of the magnetic field.

5.3.3. Unstable excitation

An unstable AVR will result in VAR swings on the power system; these swings, if large enough, should generate appropriate alarms. If the controller becomes too unstable, either the generator with the faulty AVR or healthy generators may be pushed outside of the stability limits or heating limits. In this case the generator should be removed from the system or the bus to which the generator is connected isolated. In addition to leading to a stability limit failure, an unstable AVR can make it difficult or not possible for a healthy generator set to synchronize and connect due to the large VAR swings on the bus.

5.3.4. Testing for the Worst Case Failure

The worst case failure associated with excitation failures is the loss of healthy generator(s) and subsequent loss of unhealthy generators resulting in blackout. From a detection perspective, the worst case is where two generators are online and the healthy generators cannot “vote” the unhealthy generator off: protection systems for excitation control faults that are based solely on voting on the operating points of generators cannot reliably detect the faulty generator when there are only two generators operating in parallel.

If the facility is intending to perform dynamic positioning operations with 2 generators (including 1 generator + battery configurations), excitation tests should be performed in two-generator configurations.

5.3.5. How to test for Excitation Failures

Excitation failure testing is generally performed as part of the DP FMEA program, and, provided a data-centric evidence-based approach to data collection was used, this data may be used in the OneStep Power assessment of equivalent integrity. If the data is insufficient to provide evidence of the vessel’s capability, OneStep Power can assist with performing this testing.

While excitation failure is a standard test required for both FMEA and regulatory compliance OneStep have found the testing options to be limited to the following methods:

- Opening of the field connections to induce under excitation
- Opening of the voltage sensing lines to induce over excitation
- Removal of power from the AVR to simulate AVR failure
- Manually adjusting the AVR settings to induce over or under excitation

In addition to these traditional methods of testing OneStep have added some proprietary testing technologies and techniques that do not require adjustment of the AVR or protection systems while still inducing the desired fault in a more controlled manner.

OneStep Power has developed equipment that is able to induce a slower or erratic excitation failure using the Generator Voltage Response Tester (GVRT) and/or a system of changing the feedback signal to the AVR. By altering the feedback to an AVR it is possible to induce an over-excitation event that should engage the over-excitation limiter (OEL) on the generator under test and under-excitation limiter (UEL) in healthy generators connected in parallel.

Excitation testing can be performed by using OEM or OneStep Power procedures to induce over and under excitation events on a single generator while load sharing with normally operating generators.

Acceptance criteria:

- Correct identification of faulty unit
- Correct discrimination by isolating either the faulty generator or the bus to which the generator is connected.

Note: if the protections are holistically verified, the generator can be isolated first, rather than the bus. This allows for reduction of the disturbance to the smallest possible area.

5.4. Over-voltage

There are a number of failures that can lead to an over-voltage failure. When operating in a closed bus configuration, failures that lead to an over-voltage fault should be identified by the protection systems and be isolated before over-voltage protection is required. Failures that can lead to over-voltage include:

- Over-excitation
- Earth faults
- Phase to phase faults
- Rapid Load reduction
- Network resonance
- Switching events
- Physical contact with higher voltage system
- Lightning strike

These failure modes are well described in Csanyi (2021)[2] . OneStep Power recommends any specialist practitioners interested, review this document as it is a succinct and well-rounded description of over-voltage failures: https://electrical-engineering-portal.com/damaging-overvoltages-industrial-systems

5.4.1. Testing for the Worst Case Failure

There are two worst case failures associated with over-voltage:

1. Loss of all connected power sources due to tripping on over-voltage resulting in blackout.
2. Thruster circuit breakers tripping due over-voltage resulting in total loss of station-keeping capability.

In both these cases, the primary protections should operate to prevent an extended over-voltage event occurring. In the event that the primary protection fails, the bus-ties should be set to open on over-voltage protections before any propulsion feeders or power supplies. If the facility is intending to perform dynamic positioning operations with 2 generators (including 1 generator + battery configurations), over-voltage tests should be performed in the two-generator configuration and any other relevant operational configurations.

5.4.2. How to Test for Over-Voltage

Over-voltage testing is generally performed as part of the DP FMEA program, and, provided a data-centric evidence-based approach to data collection was used, this data may be used in the OneStep Power assessment of equivalent integrity. If the data is insufficient to provide evidence of the vessel's capability, OneStep Power can assist with performing this testing.

There are a number of ways over-voltage testing is traditionally conducted, including manually adjusting the AVR set points or injection testing by the OEM. Over-voltage testing can be conducted by gradually increasing the bus voltage using OneStep Power's Over-excitation test device. The OneStep Power over-excitation device can induce a controlled over-voltage on the system without changing any system settings or parameters.

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[2] Csanyi, E (2021) Eight most damaging overvoltages in Industrial Systems (root causes and prevention). Electrical Engineering Portal (EEP) Accessed 27 January 2022 https://electrical-engineering-portal.com/damaging-overvoltages-industrial-systems

5.5. Earth/Ground Fault Testing

Earth and ground are used interchangeably in this document. The earth/ground of the system is the ship's hull and all equipment that is directly bonded to it. Earthing/Grounding should be completed in such a way that a fault does not introduce step touch potential putting life and equipment at risk.

Ground faults are the most common type of short circuit fault experienced by power systems, with industry experience agreeing that between 70 and 80 percent of faults are of this type[3]. A ground fault occurs when a live conductor connects to the ground of the system. A simplistic description of a ground fault can be given as:

$$\text{Current}_{\text{ground}} > I_C$$

Where I_C is the capacitive ground currents of the power distribution system.

There are a number of different earthing systems used in power systems, the different styles of earthing system are described in IEC 60346-3. Each of the earthing systems used in power distribution systems will give different responses to a fault, however, they are tested in similar fashion. In most cases ships are fitted with an Isolated Terra (IT) system which are discussed below. While other system implementations can be used, the actual method of testing does not vary greatly.

5.5.1. IT system

With an IT system, the generator neutral is not directly connected to the vessel's hull however a number of configurations can be implemented including:

- A fully isolated and floating system.
- A Neutral Grounding Resistor (NGR).
- An open or broken delta earth fault detection system.

An isolated and floating system requires the use of insulation monitoring systems, or similar, to identify any potential earth faults. These systems can be complex and may require automation to change detection based on network configuration.

NGR systems are used to limit the fault currents experienced when a single phase goes to ground. This is achieved by connecting the generator neutral points to the vessel's hull through an impedance that has been sized to allow detection and isolation of the fault while limiting the incident energy at the fault point.

Open or broken delta systems are implemented by using a specialised transformer that measures the voltage vectors of the system. These systems do not allow significant currents to flow yet still allow for accurate detection of earth faults and isolation of the fault from the network. This style of protection requires correctly sized equipment and detailed calculations of capacitive currents of the network to prevent false tripping.

Both NGR and open or broken delta earth fault detection systems require the use of CTs and PTs at different points in the network in order to give the required resolution.

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[3] Csanyi, E (2016) What Would Be The Worst Type Of Three Phase Faults (And Why It Happens). Electrical Engineering Portal (EEP) Accessed 20 September 2019 https://electrical-engineering-portal.com/worst-type-three-phase-faults

All systems may experience over-voltage in the event of a single phase-to-ground, or a phase-to-phase-to-ground fault. Of these faults, the single phase-to-ground fault, at low loads, results in the highest over-voltage event[4].

In all of these systems it is important that a single earth fault is isolated from the system as fast as possible. A single fault, if not correctly identified and isolated from the network, can lead to a phase-to-phase fault and result in greater system disturbance and equipment damage.

5.5.2. Testing for the Worst Case Failure

Detection of earth faults is vital to the health of the system as a two-point failure on the system can have serious consequences in excess of WCFDI.

The worst case single point failure for an earth fault is at the bus cubicle. This fault could result in propagation beyond the section in a closed bus situation and protections associated with detection and selectivity should be tested.

5.5.3. How to test for Earth Faults

Earth fault testing is performed by connecting a single phase to ground. This should be done at multiple points on the network and in all approved operating configurations i.e. open and closed bus configurations (See figure 1 over page). Comprehensive earth fault testing validates:

- Earth Fault Detection
- Earth Fault Discrimination
- Earth Fault Zones
- CT Direction
- Calculated values of earth fault analysis

Earth Fault testing should be performed as part of the DP FMEA program, and, provided a data-centric evidence-based approach to data collection was used, this data may be used in the OneStep Power assessment of equivalent integrity. If the data is insufficient to provide evidence of the vessel's capability, OneStep Power can assist with performing this testing.

Acceptance criteria:

- Correct alarms of earth faults
- Correct discrimination and isolation of earth faults

A note on "earth fault detection testing" using wire pulling: DP FMEA providers may recommend performing "Earth fault detection" testing by removing the wire or injecting a signal on the alarm. While this will validate the alarm system, it does not confirm the earth fault detection equipment or the integrated vessel response to an earth fault.

[4] Voltage-disturbance.com (2019) Voltage Swell Due to Line-Ground Fault. Accessed 27 January 2022 https://voltage-disturbance.com/power-quality/voltage-swell-due-to-line-ground-fault/

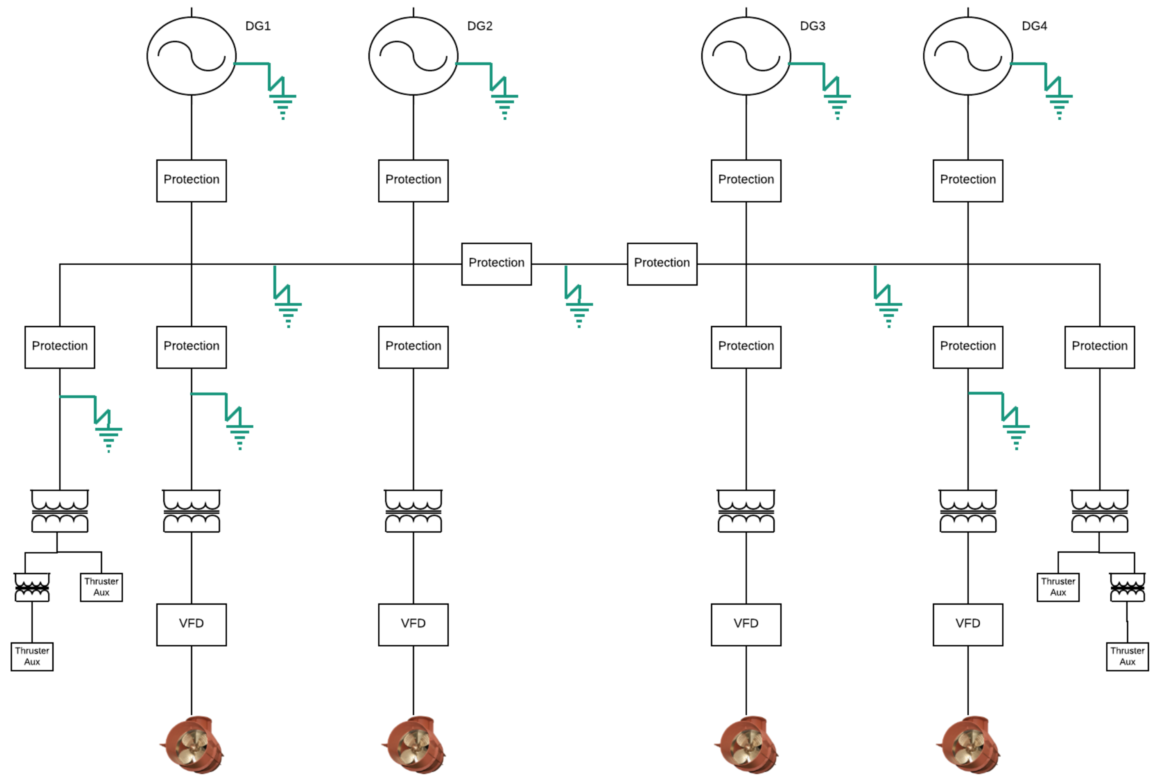


Fig. 1. Area of coverage for Earth Fault Testing: at each bus, and generator, between the buses and a selection of feeders. Depending on the protection scheme, all feeders may require earth fault testing.

5.6. Relay and Protective Device Testing

Secondary injection testing is used to confirm the correct operation of electronic and electromechanical protection devices and relays. It is accomplished by injecting voltage and currents at the correct phase angles into the protection device sensing terminals by use of a secondary injection testing tool. The tool generates voltages and currents that are the same as would be generated by the network CTs and PTs in a fault scenario, and confirms the settings and tripping times of the protection device and associated circuit breakers. It should be noted that some protective devices can be configured to trip different or multiple circuit breakers depending on fault type, severity and location.

Key information presented below is extracted from the following article, which OneStep Power recommend any specialist practitioners to review, as it is a succinct and well-rounded description of the method: https://electrical-engineering-portal.com/secondary-injection-tests

"Secondary injection tests are always done prior to primary injection tests. The purpose of secondary injection testing is to prove the correct operation of the protection scheme that is downstream from the inputs to the protection relay(s). Why done prior to primary injection tests? This is because the risks during initial testing to the LV side of the equipment under test are minimized."[5]

Secondary injection testing can be used on electronic and electromechanical protection devices to validate:

- All protection functions
- All protection settings
- Correct circuit breaker opening
- Circuit breaker opening times
- Network Coordination

5.6.1. Testing for the Worst Case Failure

The worst case for selectivity is a protection which fails to act appropriately, causing the bus and associated network to be unable to correctly isolate the fault, leading to a loss greater than WCFDI. All protections identified in the protective relay coordination study must be confirmed to operate at the correct threshold and time.

5.6.2. How to perform secondary injection testing

Inject controlled current and voltages into the protective devices using OEM-specific or approved testing equipment. Typically, OneStep Power recommends the OEM or regular vendor perform secondary injection testing as part of the 5-yearly vessel maintenance cycle as a minimum[6]. The report should include evidence of all tested protection settings and verification that the settings are in accordance with the protective relay coordination study.

[5] Csanyi, E (2017) Secondary injection tests for checking the correct operation of the protection scheme. Electrical Engineering Portal (EEP) Accessed 13 July 2021 https://electrical-engineering-portal.com/secondary-injection-tests

[6] IACS (1999) Rec 49 Testing of Protection Devices for Generators and Large Consumers on Board. Accessed 2 Nov 2021 https://www.iacs.org.uk/publications/recommendations/41-60/

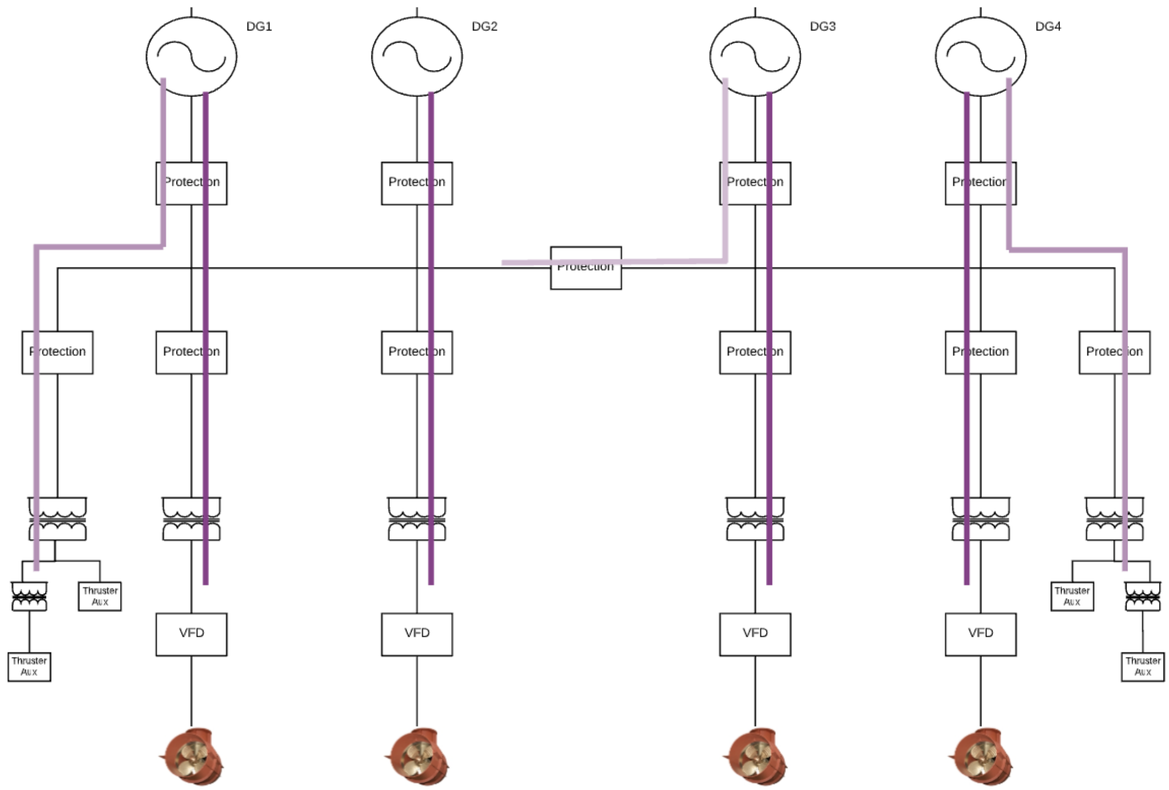


Fig. 2. *Area of coverage for secondary injection testing*

5.7. Current Sensing Testing

Validation of the current sensing equipment and interconnections is critical to the safe operation of a closed bus vessel. The most effective, comprehensive and safe method for testing current sensing equipment is to inject current directly into the bus and distribution cables of the network. This style of testing is referred to as primary injection testing.

Primary injection testing is accomplished by use of a tool that injects a high current low voltage signal onto the bus or cables that pass through the network CTs or Rogowski coils (Rcoil) and measures the resultant output at the protection device. Primary injection testing, when performed correctly, confirms not only the correct measurement devices have been installed in the correct direction but also that no transposition of interconnected wiring has occurred. Primary injection is also used to confirm correct selection and settings of Rogowski coil integrators.

Key information presented below is extracted from the following article, which OneStep Power recommend any specialist practitioners to review, as it is a succinct and well-rounded description of the method: https://electrical-engineering-portal.com/primary-injection-testing-protection-system

"Why Primary Injection Tests?

This type of test involves the entire circuit – current transformer primary and secondary windings, relay coils, trip and alarm circuits, and all intervening wiring are checked. There is no need to disturb wiring, which obviates the hazard of open-circuiting current transformers, and there is generally no need for any switching in the current transformer or relay circuits." [7]

It is OneStep Power's philosophy that primary injection does not need to be performed on a 5-yearly basis, if performed after commissioning and/or after major changes to the system, provided evidence of testing is available. It should be noted that Rogowski Coil (Rcoil) integrator units are an electronic device and the manufacturer's recommendations for testing period and type should be followed to ensure continued accurate operation.

Primary injection testing is the safest method to prove:

- CT and Rcoil ratios
- CT and Rcoil tolerance
- CT and Rcoil direction
- CT and Rcoil connections
- Interconnected wiring
- OEM Trip curves within tolerance

5.7.1. Testing for the Worst Case Failure

Worst case failure for current sensing is a situation where a CT detects a fault incorrectly and communicates this fault to the system, resulting in the spurious loss of a healthy section, and causing the fault to not be cleared within the designed limits. This could result in a system disturbance exceeding WCFDI. As such, all CTs and R-Coils on the

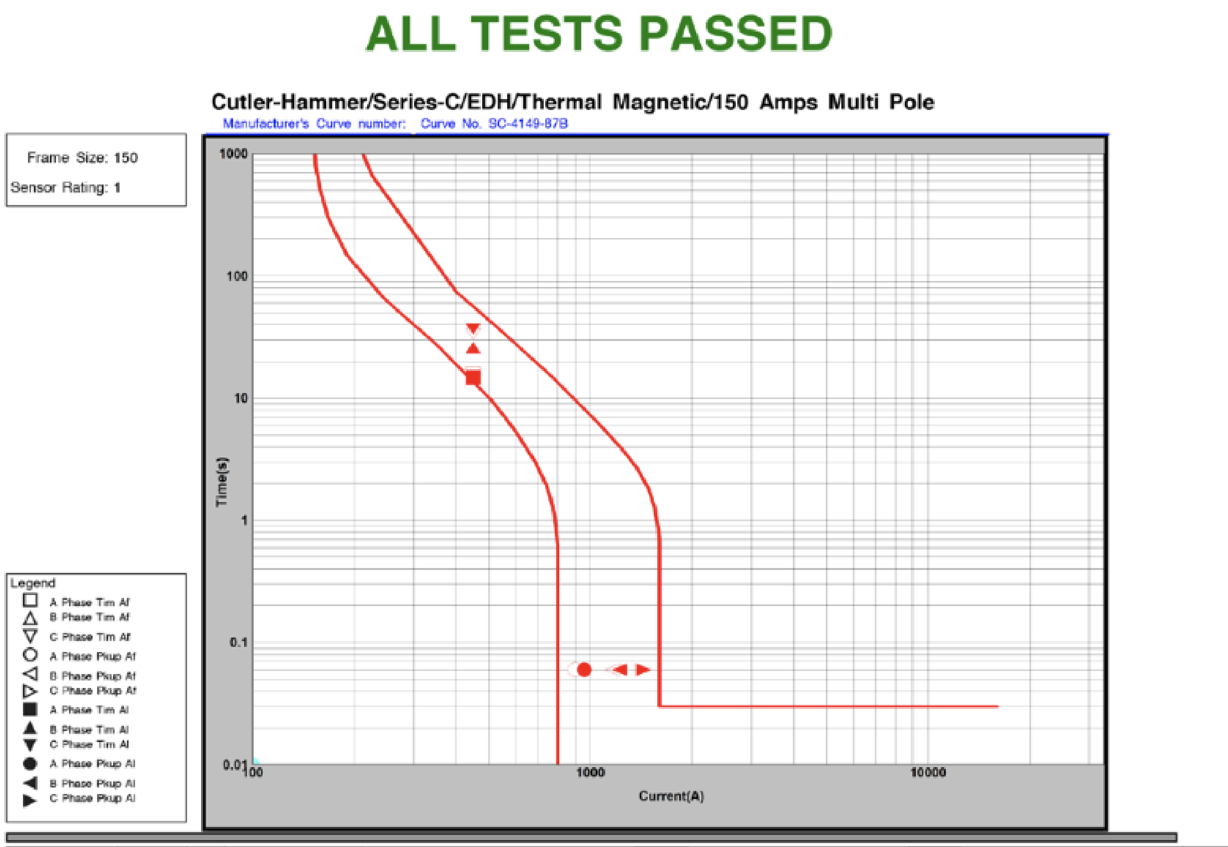
[7] Csanyi, E (2017) Primary injection testing of protection system for wiring errors between VTs / CTs and relays. Electrical Engineering Portal (EEP) Accessed 12 July 2021 https://electrical-engineering-portal.com/primary-injection-testing-protection-system

main bus, feeders from the main buses and generators should be checked for function and direction.

5.7.2. How to perform Primary Injection

"Primary injection tests are always carried out after secondary injection tests, to ensure that problems are limited to the VTs and CTs involved, plus associated wiring, all other equipment in the protection scheme having been proven satisfactory from the secondary injection tests."[8]

Testing should be undertaken using a device such as the CPC-100 unit, with the CPOL2 Polarity checker from Omicron for onsite primary injection testing. Additional auxiliary equipment may be required depending on the Facility's arrangement. Testing should be performed by trained personnel in accordance with a vessel-specific testing procedure developed based on the equipment manuals. All CTs and R-Coils on the main bus, feeders from the main buses and generators should be checked for function and direction.



Test	Nominal	Mult	Tolerance		Phase A				Phase B				Phase C				Pass/ Fail
			Min	Max	As Found		As Left		As Found		As Left		As Found		As Left		
	I(A)	x	(A) or (s)	(A) or (s)	I (A)	t(s)	I (A)	t(s)	I (A)	t(s)	I (A)	t(s)	I (A)	t(s)	I (A)	t(s)	
LT Timing	450.00	3.0	13.623	56.012	450.00	15.690	450.00	14.7	450.00	25.820	450.00	25.93	450.00	33.560	450.00	36.78	Pass
Inst Pickup	800.00		800.00	1,600.00	900.00	0.060	960	0.060	1,160.00	0.060	1220	0.060	1,420.00	0.060	1440	0.060	Pass

Fig. 3. Example of primary injection test report.[9]

[8] Csanyi, E (2017) Primary injection testing of protection system for wiring errors between VTs / CTs and relays. Electrical Engineering Portal (EEP) Accessed 12 July 2021 https://electrical-engineering-portal.com/primary-injection-testing-protection-system
[9] Megger (2014) SPI225 Smart primary injection test system. Accessed 26 October 2021 https://embed.widencdn.net/pdf/plus/megger/ib6nb31tdz/SPI225_DS_EN.pdf?u=k67mr7

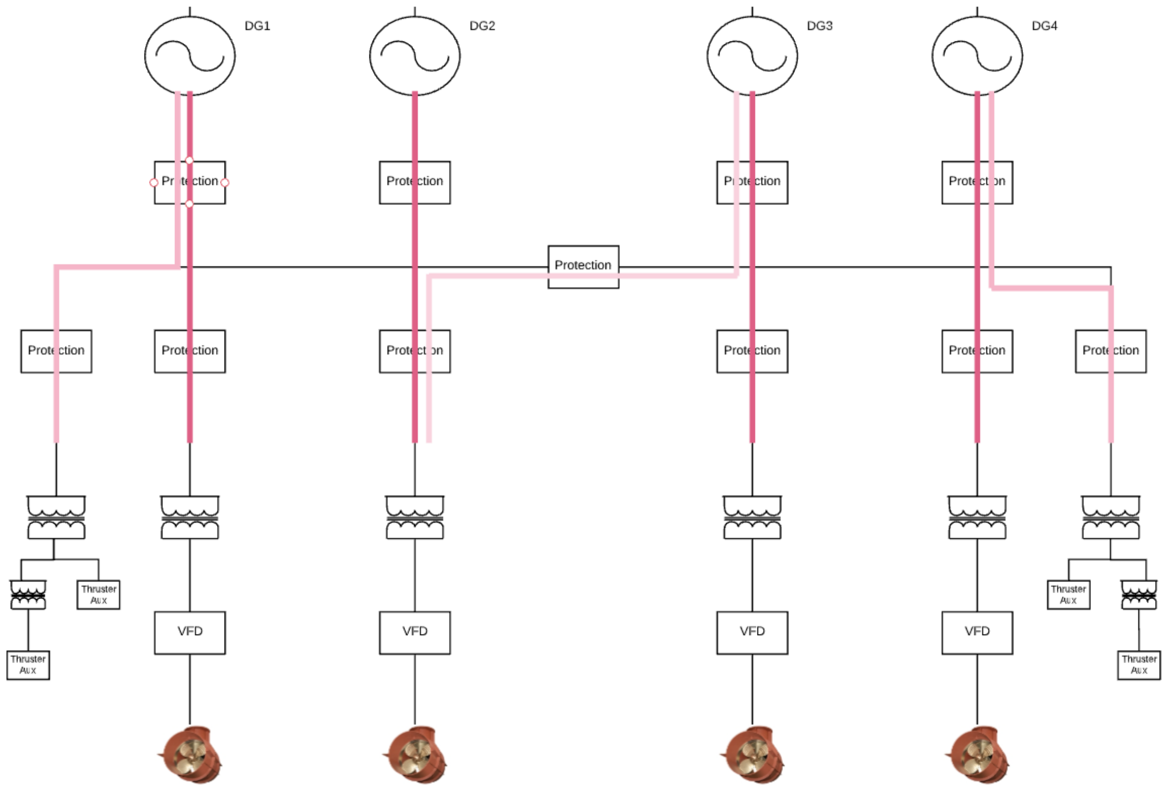


Fig. 4. Area of coverage for primary injection testing

5.8. Load Application and Rejection Testing

Vessels validating closed bus operations must consider the outcomes of significant load steps on the distribution network. Load application and rejection must be conducted to ensure system responses are within Class requirements for a system disturbance. Both the amplitude of the excursion and time it takes to stabilize after a disturbance must be within class specified limits.[10]

All major class societies have a requirement for transient stability similar to the below:

> d) After a transient condition has been initiated, the voltage in a main distribution AC system shall not differ from nominal system voltage by more than ±3% within 1.5 s. In an emergency distribution system the voltage shall not differ from nominal system voltage by more than ±4% within 5 s.
> (See IEC 61892:3, Sec.5.2.3.2)

Fig. 5. Extract from DNV Offshore Standards - DNV-OS-D201, Edition July 2021, Electrical Installations Section 1.2.3

In cases where the AVR and/or speed controllers are not correctly tuned, load application and rejection can lead to significant voltage and frequency deviations. The deviations, if extreme, have the potential to destabilize the network and lead to instances of blackout.

In addition to testing system stability and recovery times, load application testing is used to verify power management system responses such as load shedding and phaseback of drives when implemented.

Load application and rejection testing is performed to validate:

- System stability during large load swings
- Settling time after an a significant load change
- Power management functions such as load shedding and phaseback

5.8.1. Testing for the Worst Case Failure

On load application, the system may not respond quickly enough, leading to multiple generators tripping on under-frequency, under-voltage or similar protections, resulting in failure exceeding WCFDI.

On load rejection, if the system does not react with a critically damped response, the system may induce over-speed or over-voltage on multiple generators, causing failure exceeding WCFDI.

Load step testing should be conducted in a manner that is representative of the configurations the vessel will be operating in. For example, if the system is designed to operate with a single generator on one bus with energy storage on the second bus and bus-ties closed, testing should include removal of the online generator, while at or close to 100% load. This test should demonstrate that the power management system and energy storage systems have been correctly configured, and do not result in a blackout.

[10] DNV Rules for Classification: Ships 2021, Part 4, Chapt 2, Section 5/1.1. Accessed 12 Sept 2021, https://rules.dnv.com/docs/pdf/DNV/RU-SHIP/2021-07/DNV-RU-SHIP-Pt4Ch8.pdf

5.8.2. How to perform Load Application and Rejection Testing

The most effective way to perform load application and rejection testing is with the use of load banks connected to the main bus. Load banks allow for precision control of the load, both active and reactive, that is being applied to or removed from the distribution network. The drawbacks of using load banks include the impracticality, expense and time associated with installing and uninstalling the units.

Load banks should always be used for a vessel's first commissioning, subsequently, load testing may be conducted using the ship's load if it can be suitably controlled. For load application, it may be possible to use thrusters and large consumers such as drawworks and/or fire fighting pumps. For load rejection, it is possible to load the system with thrusters and other auxiliary loads and use shutdowns or opening circuit breakers to unload.

Marine generators are rated to maintain voltage and frequency within the Class Society limits for load steps of 33% to 50%. Load steps of at least 80% should be undertaken during equivalent integrity validation to confirm blackout does not occur, although the voltage and frequency may exceed the limits set for Class prescribed load steps[11]. Load rejection should be validated at as close to 100% as practicable.

[11] DNV Rules for Classification: Ships 2021, Part 4, Chapt 2, Section 5/1.2.4. Accessed 12 December 2021, https://rules.dnv.com/docs/pdf/DNV/RU-SHIP/2021-07/DNV-RU-SHIP-Pt4Ch8.pdf

5.8.3. Phaseback & Load Shedding

Phaseback and Load Shedding are implemented to ensure that sudden disturbances of either increased active power demand, or reduction in available active power, do not result in generators tripping offline. A sudden increase in demand from a generating unit can result in a reduction of bus frequency, or increase of current above the overload limits of the circuit breakers. Instances of events requiring phaseback or load shedding can include:

- Mechanical or electrical failure of an online generator
- Squalls or wind gusts
- Sudden demands in load due to failure of controllers
- Electrical faults on the network
- Starting of large consumers

Starting of large consumers should be considered in the power management system. The system should be set so that in instances where available active power is lower than the power required to start such a consumer, the consumer is inhibited from starting until either more power has been brought online, or demand has been reduced.

Phaseback and load shedding can be triggered by:

- Frequency limits
- Bus power limits
- Generator power limits
- Protective systems that trigger load reduction on events in the network
- Other protections

While the implementation method varies from installation to installation, the overall effect is the same: when a limit is reached or an event occurs, load is removed or rapidly reduced from the network in an effort to avoid overload and blackout.

5.8.4. Testing for the Worst Case Failure

A power management system which fails to limit load, experiences a sustained overload of the system. This sustained overload would lead to multiple generators tripping on overload (either simultaneously or in a cascade), leading to loss beyond WCFDI.

5.8.5. How to perform Phaseback and Load Shedding Testing

Due to the varying methods of implementation of phaseback and load shedding, there is no single test methodology available. However all testing for phaseback and load shedding must be done using the loads available on the network. Testing may be completed in a fashion similar to Section 5.7.

5.9. Phase Imbalance Testing/Shorting a CT

Causes of phase imbalance include:

- Incorrectly balanced single phase loads
- Motor winding failure
- Loss of a phase
- Phase to phase fault
- Phase to ground fault

Phase imbalance will result in negative and zero sequence currents in the system that can cause heating in generators, transformers and motors. Detecting the introduction of imbalance is achieved using protective devices using core CTs and PTs.[12] [13] [14].

Phase imbalance testing is performed to validate:

- Correct detection of failures
- Correct discrimination

5.9.1. Testing for the Worst Case Failure

Incorrect coordination resulting in operation of generator protections for a downstream phase failure could lead to loss greater than WCFDI.

5.9.2. How to perform Phase Imbalance Testing

In cases where protection relays are set for phase imbalance protection it is possible to use secondary injection testing to verify the correct setting of limits and timing on phase imbalance.

In cases where it is not possible or practical to use injection testing, other testing methodologies can be implemented. These alternate methods depend on the style of protection that has been applied to the network that is under test and can include:

- Open circuiting a single phase of a main feeder such as a bus feeder, transformer feeder etc.
- Short circuiting a CT secondary
- Open circuiting a single phase of a PT secondary
- Phase to earth fault

[12] Csanyi, E (2020), Protection of three-phase motors from unbalance (Loss of phase and phase rotation). Electrical Engineering Portal (EEP) Accessed 25 October 2021 https://electrical-engineering-portal.com/protection-three-phase-motors-from-unbalance-phase-loss-rotation
[13] Csanyi, E (2015), Voltage Imbalance Protection of Synchronous Generator (ANSI code 60) . Electrical Engineering Portal (EEP) Accessed 25 October 2021 https://electrical-engineering-portal.com/voltage-imbalance-protection-of-synchronous-generator-ansi-code-60
[14] Bennett, B. ABB (2015) Unbalanced voltage supply The damaging effects on three phase induction motors and rectifiers. Accessed 25 October 2021 https://library.e.abb.com/public/0c4186f3e7354f6982124decf92742d8/AVC-20%20white%20paper%20(low%20res).pdf

5.10. Blackout Recovery Testing

While the ultimate goal of dynamic positioning is to remain on station while only losing a section of the vessel based on its WCFDI, blackout recovery must be considered. Testing for section blackout recovery should be performed, as well as complete blackout recovery. Cold starts need not be considered.

5.11. Harmonic Distortion Testing

Harmonic distortion is generally caused by consumers with high speed switching mechanisms such as variable frequency drives, silicon controlled rectifiers (SCRs), switch mode power supplies and other power electronic devices. The THD shall not exceed 8%, and any single harmonic shall not to exceed 5% as per ABS[15] and DNV[16]. In essence total harmonic distortion (THD) on the main bus must be lower than the regulatory limits i.e

$$THD_{Bus} \leq THD_{Regulation}$$

Harmonic distortion is understood by manufacturers of modern power equipment and two main methods of mitigating harmonics are utilised, the first being harmonic canceling techniques and equipment embedded in the consumer. The second being harmonic filters installed in strategic locations in the power distribution network.

5.11.1. Testing for the Worst Case Failure

With networks that utilise harmonic filters, consideration should be given to failure of a harmonic filter or other harmonic cancelling devices.

5.11.2. How to perform Harmonic Distortion Testing

A harmonic distortion study should be completed as part of the initial design of the vessel. This study should be done to evaluate the system running in the operational bus configurations with a variety of expected loads. This study can then be verified by use of a THD meter. THD meters are normally integrated into modern electronic power meters. The failure that leads to the highest THD must be considered and verified not to exceed Class limits.

For systems with harmonic cancelling devices, a model of the network response to a harmonic canceling device failure should be provided. This model should then be verified by measuring the THD in operational configurations with a variety of loads both with and without the harmonic cancelling device functioning.

[15]ABS (2021) ABS Rules for Building and Classing Marine Vessels 2021, Part 4, Chapt 8, Section 2/7.21, 4-8-2/9.22, 4-8-2/9.23. Accessed 12 Sept 2021, https://ww2.eagle.org/content/dam/eagle/rules-and-guides/current/other/1_marinevesselrules_2021/mvr-part-4-july21.pdf

[16] DNV (2021) DNV Rules for Classification: Ships 2021, Part 4, Chapt 8, Section 2/1.2.7. Accessed 12 Sept 2021, https://rules.dnv.com/docs/pdf/DNV/RU-SHIP/2021-07/DNV-RU-SHIP-Pt4Ch8.pdf

5.12. Fault Ride Through Testing

When describing fault ride through testing the dynamic positioning industry is referring to a network's capability to ride through serious voltage transients associated with short circuit faults.

The voltage waveforms associated with a short circuit are a sudden drop in voltage followed by a recovery that will overshoot the system nominal voltage. The failure mechanisms associated with the transient voltage can include loss of auxiliary systems, loss of drives or thrusters, loss of controllers or loss of buses.

The under-voltage section of the transient waveform can result in loss of power to controllers or auxiliary equipment due to control relays and motor contactors opening. Loss of power to buses can be experienced with under-voltage trips not being equipped with suitable delays to prevent premature opening.

Failures that can be experienced with the transient over-voltage section of the waveform can include main drives tripping on DC link over-voltage and damage to equipment if the transient over-voltage section is too extreme.

Fault ride through testing is undertaken to verify:

- All unfaulted buses that power DP systems stay online
- Drive ride through settings are correct
- DP critical auxiliary equipment such as cooling and oil pumps stay online
- AVRs are correctly tuned

5.12.1. Testing for the Worst Case Failure.

The worst case failure for fault ride through testing is a three-phase short circuit on the main bus. This scenario is described in more detail in sections following. Testing for the worst case failure should consider transients on all drives and consumers as would be encountered in a short circuit.

5.12.2. How to perform Fault Ride Through Testing

Traditionally ride through testing was accomplished by opening and closing of a single breaker such as a generator or bus-tie in fast succession. This however only produced the low or zero voltage component of the transient. The introduction of live short circuit testing on high voltage systems resulted in an accurate waveform, however it was at the cost of system degradation and possible damage. Live short circuit testing of low voltage systems is generally not an option due to the high likelihood of serious damage.

The development of OneStep Power's patented Generator Voltage Response Tester (GVRT™) introduced a method of achieving an under-voltage event followed by a transient over-voltage without the risk of damage to the network. To introduce a sharper and more pronounced low voltage transient, OneStep power developed the ZeroDip™. When the GVRT and Zero Dip are used together, a voltage waveform representative of a short circuit is achieved.

Fault ride through testing should be conducted for a minimum period which is equal to or greater than the tripping time of any bus-ties. More information on fault ride through testing is presented in Section 6.

6. Short Circuit Testing

There are a number of short circuit faults that can be experienced by a distribution network, including:

- phase-to-ground
- phase-to-phase
- phase-to-phase-to-ground
- phase-to-phase-to-phase
- phase-to-phase-to-phase-to-ground

Strictly speaking, a single phase-to-ground can be classified as a short circuit, however correct network configuration will reduce the impact of a phase-to-ground fault. Due to the reduced impact phase-to-ground faults are normally referred to as earth or ground faults and are discussed in the earth/ground fault section of this document.

Phase-to-phase-to-phase faults, referred to as three phase symmetrical faults, are the rarest faults. The writers could find no evidence of an event on a vessel where a three phase symmetrical fault occurred on a main bus that was equipped with metal clad switchgear. While rare, a three phase symmetrical fault has the highest fault currents and is the easiest to model. When discussing short circuits in the rest of this section, unless otherwise stated, reference is being made to a three phase symmetrical short circuit.

All instances of two and three phase short circuits, while not common, do have the potential to cause equipment damage and blackout the entire network if not correctly identified and isolated. The major difference between a short circuit and many other styles of fault is that even with a correctly configured and tested protection system, the entire network can suffer major disturbances depending on the magnitude of the fault.

As a short circuit fault has the potential to cause a disturbance on the entire network, proving the ability of the protection system to correctly identify and isolate the fault is not sufficient to verify the system for closed bus operations. In addition to proving the capability of the protection system, the network's ride through capability must also be verified to ensure that the transient conditions do not result in loss of critical equipment.

When discussing the requirements of a robust power system in reference to dynamically positioned vessels, hidden failures must also be considered. A hidden failure can be considered as anything that could potentially stop the protection system from operating without giving warning to the operator. For example, a protection relay having a faulty output contact that fails to send the trip signal to the appropriate circuit breakers. For this reason it is a requirement to have both a primary and a secondary scheme in place to ensure that a short circuit fault is isolated from the network. It should also be noted that because these hidden failures do exist it is important that a robust and comprehensive maintenance and testing program be implemented on vessels operating in closed bus configuration.

Verification of a distribution network's ability to effectively and safely survive a short circuit fault must include evidence that:

- primary protection systems correctly detect the fault
- secondary protection systems correctly detect the fault
- both primary and secondary protection systems isolate the smallest possible section of the network
- supporting equipment such as AVR boost circuits operate correctly

- AVRs and speed controllers are correctly tuned and will not become unstable post fault, leading to cascade failures such as pole slip
- critical equipment not supplied from the faulted zone continues to operate through:
    - low voltage transient
    - over-voltage transient

6.1. Characteristics of a short circuit

When a short circuit event occurs the subsequent response is a well defined series of events that have different effects on the generators, transformers and power distribution network. The sequence is as follows:

1. Subtransient Period:
    1.1. Highest current level with a DC component that can double the fault current if the fault occurs at the zero crossing of the waveform. This current is calculated according to *IEC 60909-0*.
    1.2. Voltage at the output terminals of the generator drops toward zero which in turn causes the AVR(s) to increase excitation in an attempt to increase output voltage.
    1.3. Subtransient generally only lasts from 1 to 3 cycles and quickly decays .
2. Transient Period:
    2.1. Lower current than the initial subtransient period, but still in excess of the machines rated short circuit current.
    2.2. Causes fast heating of components on the fault path and generator.
    2.3. Voltage stays at close to zero volts.
    2.4. Transient period can last from 10's to 100's of cycles depending on generator construction and has a lower decay rate than the sub transient period.
3. Steady State Period:
    3.1. High current that lasts until the protection measures are engaged. During this period thermal stress is built up in the generator(s) windings and transmission lines, resulting in mechanical stress.
4. Fault clearance, eg: high current trip of feeder circuit breaker:
    4.1. Voltage starts recovering and transitions to an over-voltage event, produced by the over-excitation event induced in the low voltage period of the fault; this should settle after a few seconds depending on the AVR(s) control loop settings.
    4.2. Speed of generator(s) may ramp up as a response to a sudden load reduction and should stabilize in a few seconds.

Note: This sequence assumes an AVR circuit with over-excitation/boost capability to maintain a short circuit rating of 3 x I_n for 2 seconds, where I_n is the nominal rating of the generator current as per class requirements.

For ABS: *"3.9 Short Circuit Capability Short circuit capabilities of generators are to be in accordance with IEC Publication 60034-1. Under short circuit conditions, generators are to be capable of withstanding the mechanical and thermal stresses induced by short circuit current of at least three times the full load current for at least 2 seconds. "*[17]

[17] ABS (2021) ABS Rules for Building and Classing Marine Vessels 2021, Part 4, Chapt 8, Section 3. Accessed 12 Sept 2021, https://ww2.eagle.org/content/dam/eagle/rules-and-guides/current/other/1_marinevesselrules_2021/mvr-part-4-july21.pdf

For DNV: *"<u>2.3.1 Short circuit withstand and contribution capabilities</u> a) Generally, AC synchronous generators, with their excitation systems, shall, under steady short circuit condition, be capable of maintaining, without sustaining any damage, its short circuit current, which shall be at least three (3) times the rated full load current, for a duration of at least 2 s. (IEC 60092-301 modified clause 4.2.3)"* [18]

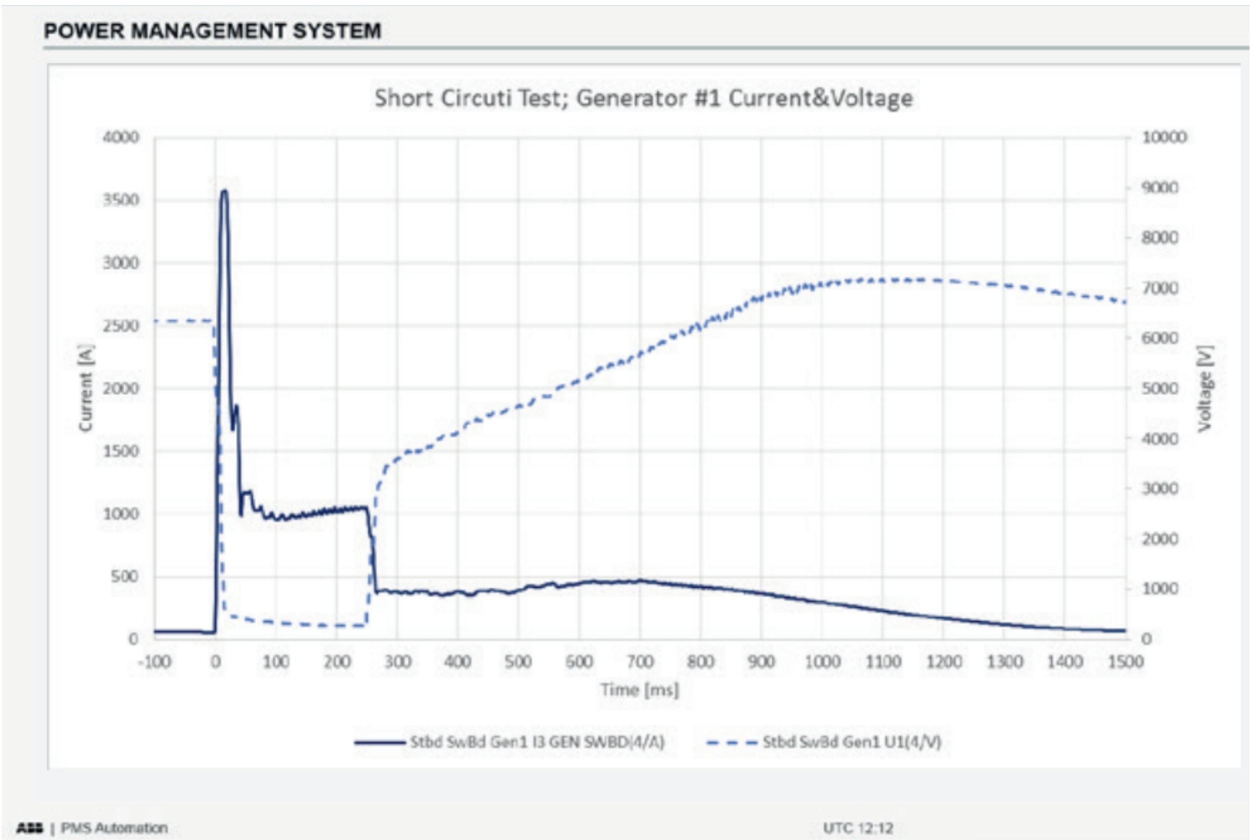


Fig. 6. Example of voltage and current trends during a OEM-performed short circuit test. Sub-transient and transient conditions are completed within 50ms, fault is cleared after 250ms. Source: ABB[19]

[18] DNV (2021) DNV Rules for Classification: Ships 2021, Part 4, Chapt 8, Section 5/2.3.1. Accessed 12 Sept 2021, https://rules.dnv.com/docs/pdf/DNV/RU-SHIP/2021-07/DNV-RU-SHIP-Pt4Ch8.pdf
[19] ABB Advanced Power Systems (2017) Short circuit testing HV Power Systems. Accessed 26 October 2021 https://search.abb.com/library/Download.aspx?DocumentID=3AJM005000-0085&LanguageCode=en&DocumentPartId=&Action=Launch

6.2. Live Short Circuit Testing

Live short circuit testing is accomplished by bolting the three phases to each other and to ground on the load side of a circuit breaker connected to the main bus[20]. The circuit breaker is then closed onto this fault initiating a three phase to ground short circuit. To prove the coordination of the bus-tie and generator circuit breakers, it is necessary to change the timing or disable the protection functions from the circuit breaker closing onto the fault, and ensure the fault is connected on the bus side of any zone protection schemes.

Short circuit testing verifies:

- generator/s connected to the bus have the correct fault current capability
- AVR/s of the generator/s used can supply the required boost current
- affected generator/s control system stability
- correct operation of the fastest detection and protection that is enabled
- correct CT type, installation and interconnections of the protection under test
- fault ride through of the equipment including
  - low voltage transient
  - over-voltage transient

When performing live short circuit testing, the protection scheme needs to be fully understood and the protections and equipment that are being verified clearly defined. It is imperative that any changes to protection settings required to facilitate this testing must be returned to the original settings and revalidated after testing.

[20] MTS_TECHOP-ODP-09 (2015) A Method for proving the Fault Ride-Through Capability of DP vessels with HV Power Plant, Accessed Online March 2018 http://dynamic-positioning.com/files_mailing/Techop%20Fault%20Ride%20Through.pdf

6.2.1. System Setup for Live short-circuit test.

- Generally only one or two generators (out of 6-7) are connected to feed the fault.
- A bolted short is installed across terminals downstream a feeder.
- The feeder is remotely closed and then open to remove the fault.

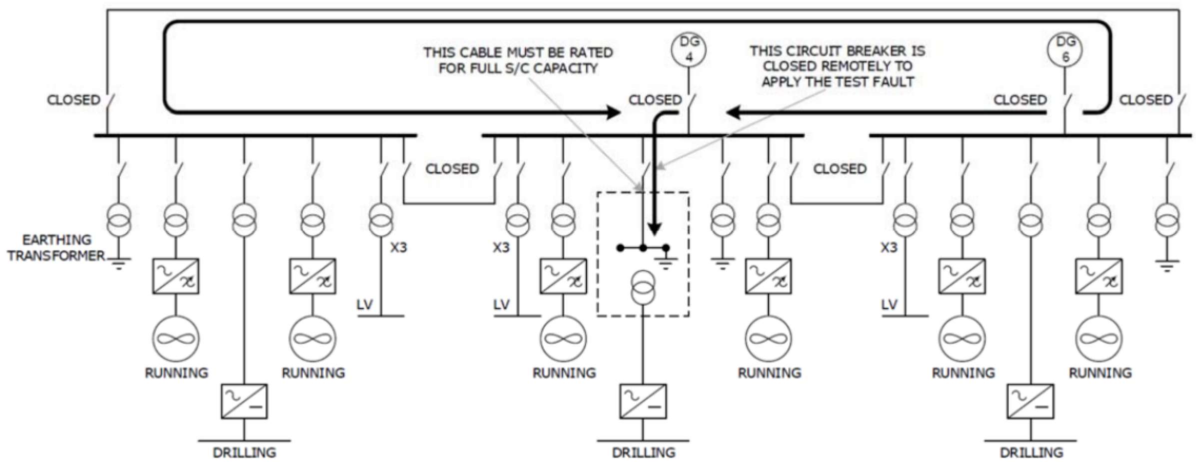


Fig. 7. Typical ring bus arrangement of Fault Ride Through testing using a bolted 3-phase symmetrical short-circuit.[21]

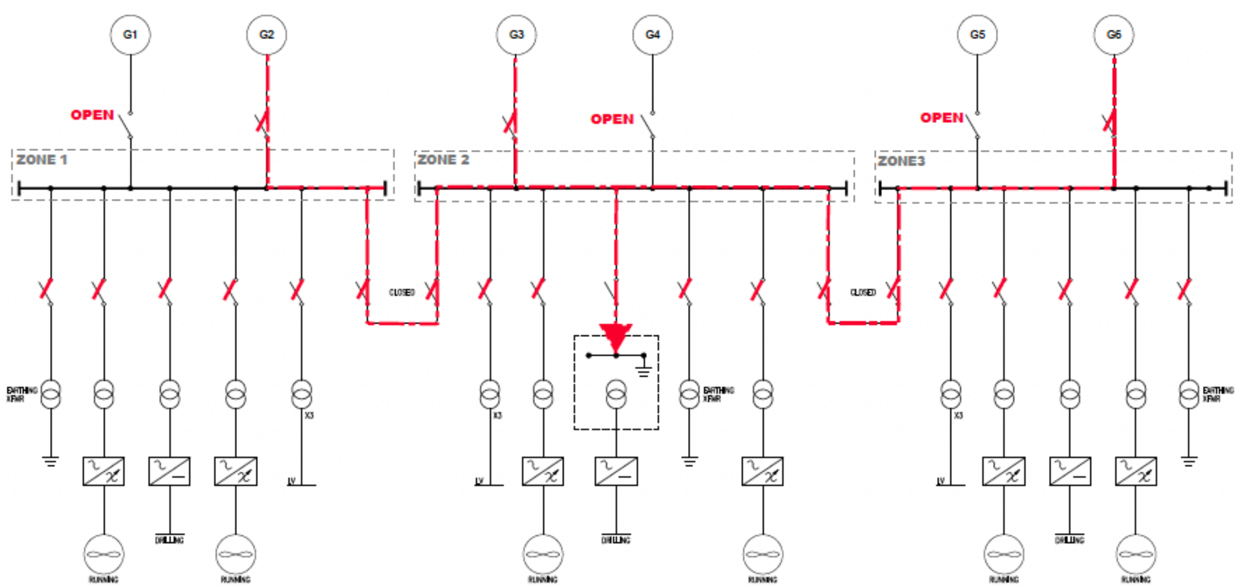


Fig. 8. Typical system arrangement (closed bus) of Fault Ride Through testing using a bolted 3-phase symmetrical short-circuit.

[21] Roa, M. (2016) Alternative Approaches for Demonstration of Fault Ride-through Capability on DP Vessels with Closed Bus Operation, presented at MTS DP Conference - Houston, TX, October 11-12, 2016 - http://dynamic-positioning.com/proceedings/dp2016/PowerTesting_Selvan_2016.pdf

6.2.2. Observations Regarding Live Short Circuit Testing

A short circuit test will verify:

- Generator/s that were subject to the fault are capable of supplying the required short circuit current
- Protection system coordination along the fault path is correct for the protection that has been set to operate first
- Thrusters and auxiliary systems ride through the transient voltage response
- If performed in accordance with MTS TECHOP-D-07 section 8.6.6, all buses in the system will experience the short circuit voltage transients.

6.2.3. Build to Test Vessels

The MTS DP Committee's TECHOP D-07[22] recommends new-build vessels incorporate a "Built to Test" Philosophy, which provides extended service life as part of the intention to perform live short circuit tests.

OneStep Power recommends partial discharge testing before and after short circuit testing is undertaken. Partial discharge testing should be performed on switchboards, generators and main termination connections subject to short circuit currents to identify any degraded insulation and loose windings. More details on partial discharge testing are available at: https://hvtechnologies.com/the-basics-of-partial-discharge-testing/.

[22] MTS_TECHOP-D-07 (2021) A Method for proving the Fault Ride-Through Capability of DP vessels with HV Power Plant, Section 7.1.5. Accessed 6 Jan 2022 https://dynamic-positioning.com/files_mailing/TECHOP%20(D-07%20-%20Rev1%20-%20Jan21)%20PROVING%20FAULT%20RIDE-THROUGH%20CAPABILITY%20OF%20DP%20VESSELS.pdf

6.3. OneStep Power's Fault Ride Through (VDRT + ZVRT)

Until the development of the GVRT and ZeroDip, the only way to verify the response of a system for the over-voltage transient was the application of a short circuit or manually controlling AVR's in the system coupled with forcing breakers to open and close. The existing styles of testing were not repeatable and required the changing of many settings to both the protections and controllers in the network. OneStep's GVRT and ZeroDip technologies give a controlled way to induce a voltage drop followed by an over-voltage transient that is a response generated by the system and does not require any changes to the system settings.

Each test device developed by OneStep Power operates in an "as-is" arrangement with the ship - there are no protection setting changes required, and generally no physical change to the vessel arrangement to perform testing.

All OneStep Power testing has been designed to incorporate high-speed data capture that will give stakeholders the ability to review results and draw conclusions.

6.3.1. GVRT Theory of Operation

The GVRT interrupts the excitation current from the AVR to the field winding causing a reduction in the magnetic field of the rotor of the generator and the internally generated voltage (E_A). It must be noted that E_A is the internal generator voltage, not the terminal voltage V_t of the machine. In a system with multiple generators connected, a drop in E_A of a single generator will result in a reduction of VARs produced by the machine, while the generator terminals will remain at the network voltage.[23] In the case of a single generator connected to the network, a drop in E_A will result in a drop of the terminal voltage and the network voltage. A reduction of excitation on all machines simultaneously results in reduction in network voltage. Appendix A gives greater detail on how the GVRT is temporarily installed.

The GVRT ride through testing sequence is:

1. The selected AVRs are switched from the generator field winding to an internal resistive inductive (RL) load
2. The generator terminal voltage starts to decrease
3. The AVR output current increases in an attempt to maintain the correct terminal voltage
4. The AVR output stays switched to the RL load and continues to increase while the terminal voltage continues decrease for the test duration
5. When the test time elapses, the AVR, still producing a large excitation current, switches to back to the field
6. The high excitation current is applied to the generator field winding causing the terminal voltage to start to recover and subsequently overshoot the network's nominal voltage

[23] This allows the GVRT to be used for VAR testing in addition to ride through testing.

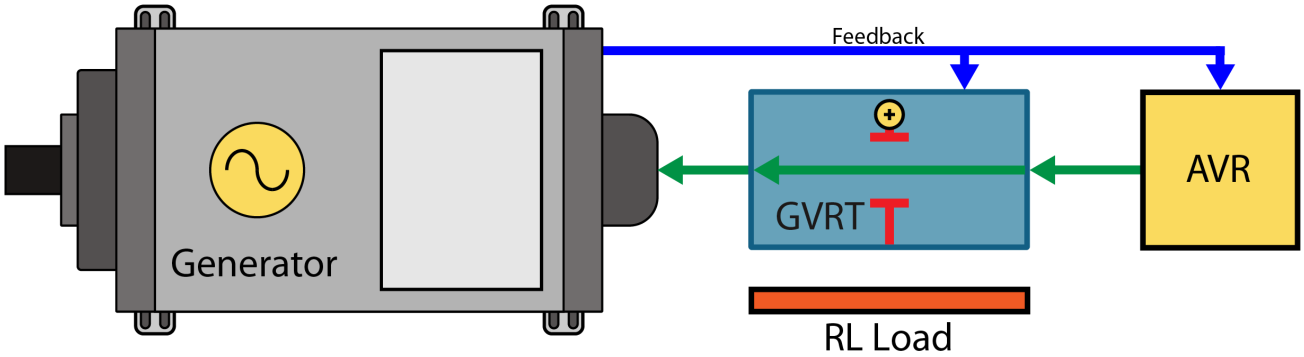


Fig. 9. GVRT arrangement - Uninterrupted AVR control pre and post test

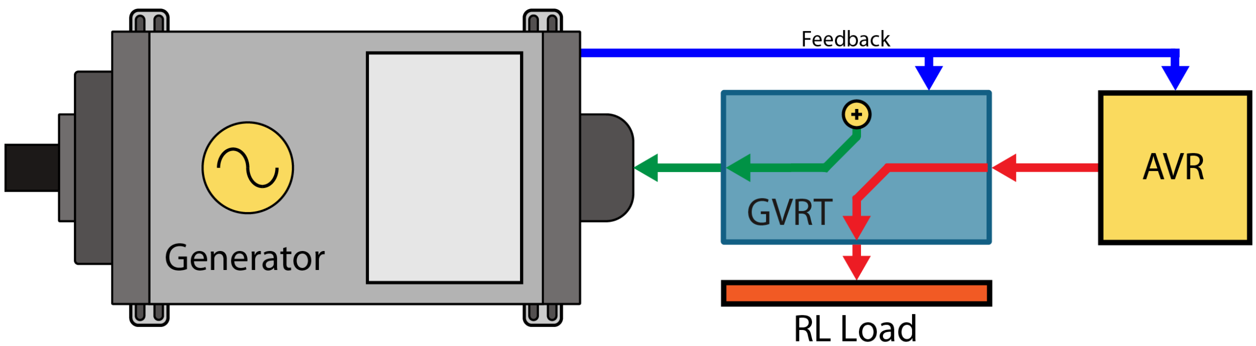


Fig. 10. GVRT arrangement - AVR to RL Load during test

Figure 11 over page shows the response of a system subjected to a GVRT only test. The orange shaded area starts when the AVR is switched to the RL load. This area clearly shows the reduction in terminal voltage results in an increase in the AVR current output. The green shaded area is after the AVR current has been returned to the field winding. Here the natural response of the AVR can be seen along with the overshoot of the system voltage.

The 'messy' current in the orange section of the graph is a result of the lower inductance of the RL load and switching speed of the pulse width controller of the AVR. Even though it is not a smooth curve it clearly shows the increase in excitation current of the system.

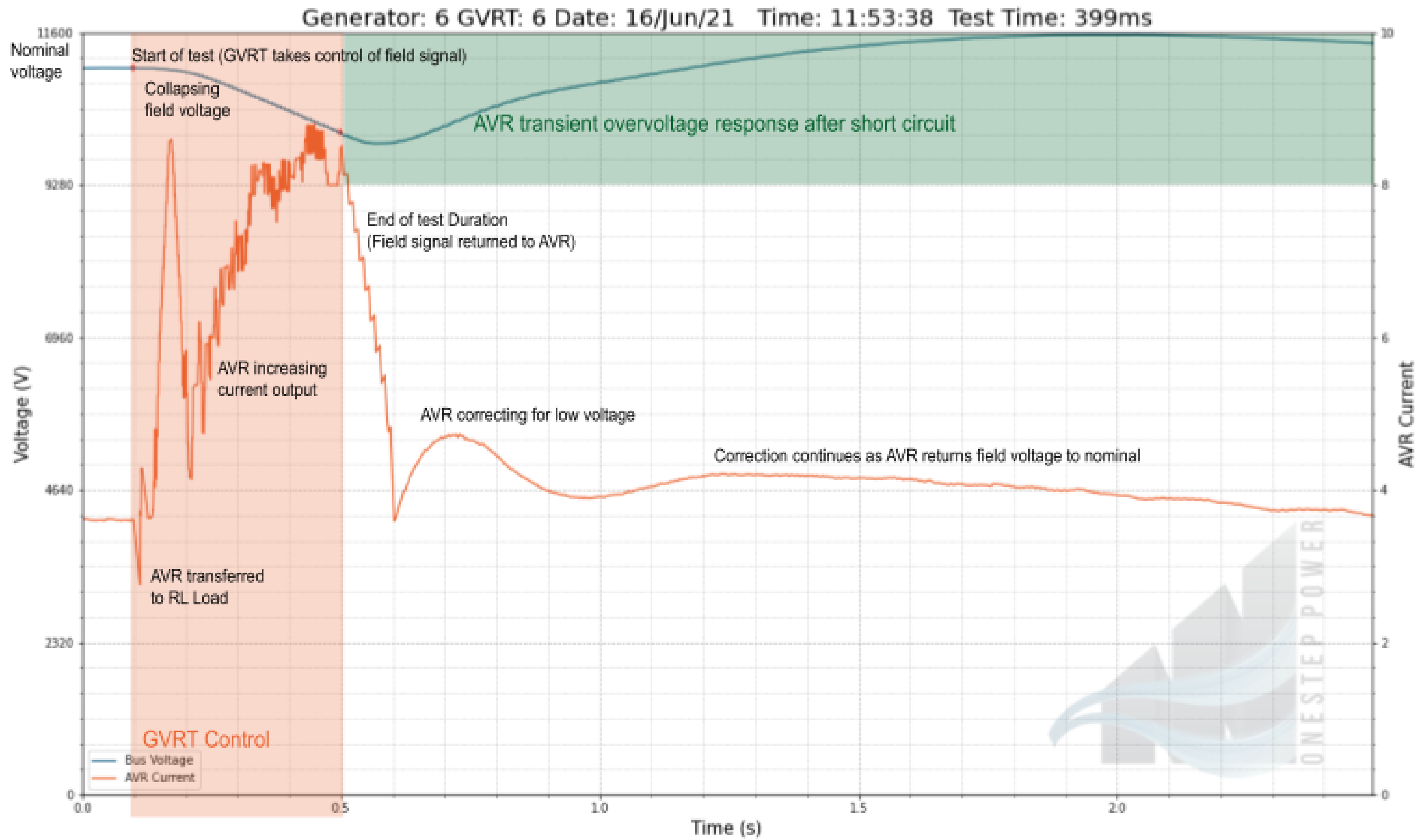


Fig. 11. 400ms VDRT test on an 11kV generator

In addition to verifying the response of the networks and consumers attached to the network under test, this style of testing also verifies the stability of the AVR. A number of systems have been tested after an upgrade of the AVRs has taken place. In more than one case, this testing has proven that while stable during normal load conditions the PID tuning is not correct and leads to instability after a transient. Figure 12 shows the response of a system that passed load step testing but was clearly unstable with even a small transient event.

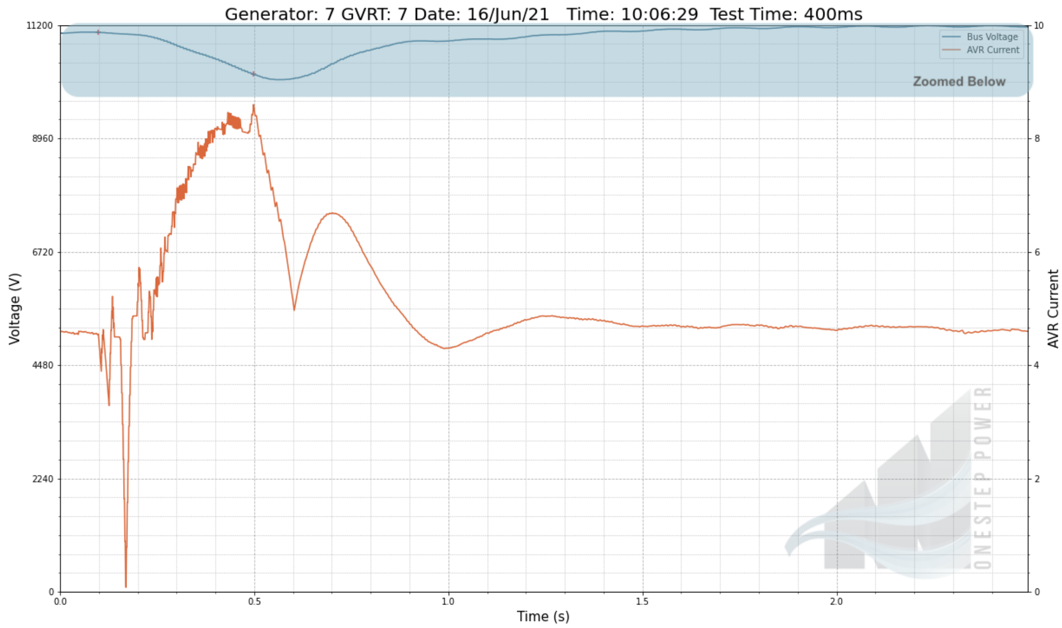


Fig. 12. Image of unstable AVR response. Refer to zoomed-in image below for indication of instability.

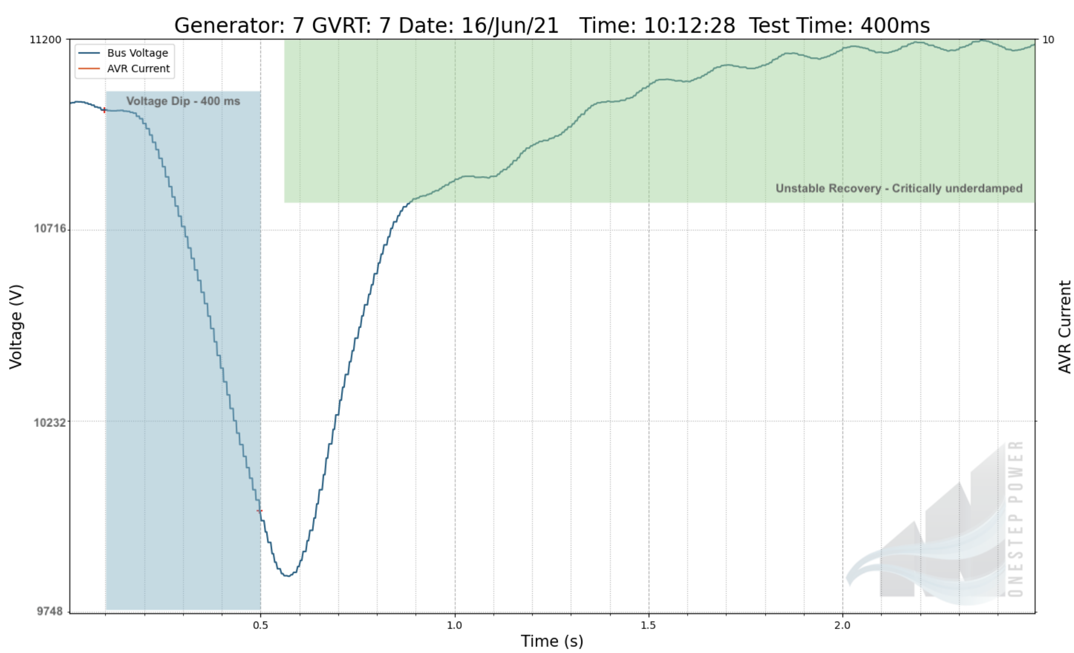


Fig. 13. Unstable AVR response (refer to previous figure for full context of test)

6.3.2. ZeroDip Operation

The GVRT waveform provides a good match to short circuit behaviour for the transient over-voltage after a fault has been cleared. However, the GVRT alone is unable to provide the controllable, low voltage event experienced during the period before the short is cleared from the system. As a result, OneStep Power developed ZeroDip™ to induce the low voltage section of the waveform. The ZeroDip uses a controlled high speed circuit breaker switching logic to induce an event isolating all incoming supplies to the section of the network under test. The ZeroDip then re-applies a supply once the test time has elapsed. As switching generators and bus-ties does carry an inherent risk associated with closing unsynchronized power supplies, the ZeroDip has built-in interlock features that prevent synchronization crash. For further details on how the ZeroDip is temporarily installed, please refer to Appendix B.

ZeroDip can induce the low voltage ride through test on:

- each bus-bar individually or
- all busses if a single generator is sufficient to power the vessel systems or
- multiple bus sections depending on the network bus configuration.

Figure 14 represents the voltage response of a bus when a ZeroDip test is performed. Note: While the ZeroDip removes the supplies to a section of the network, the voltage may not fall to zero instantly. The reduced rate-of-change of the falling voltage is a function of equipment connected to the system and is detailed in IEEE 1159-2019[24] This sample from a DP3 vessel is illustrative of the slowest response observed to date. Loads on the network may act as generators for a brief period of time resulting in a decay curve rather than an instant drop. Many systems with different loads produce a more rapid response, such as the example in Figure 18.

This observation is explained further in section 6.5 and does not impact the validity of the test as the electrical equipment such as motor control circuits, under-voltage relays, electromechanical relays, etc will generally have a drop-out voltage of between 60 and 70 percent of rated voltage[25] [26].

[24] IEEE (2019) IEEE 1159-2019 Recommended Practice For Monitoring Electric Power Quality.
[25] Csanyi, E.(2013) Impacts of Voltage Dips on Power Quality Problems. Electrical Engineering Portal Accessed 27 Jan 2022 https://electrical-engineering-portal.com/impacts-of-voltage-dips-on-power-quality-problems
[26] Glenn, B (2020) Contactor and Control Relay Ride-Through. Electrical Construction & Maintenance (EC&M) Accessed 27 Jan 2022 https://www.ecmweb.com/power-quality-reliability/article/21120450/contactor-and-control-relay-ridethrough

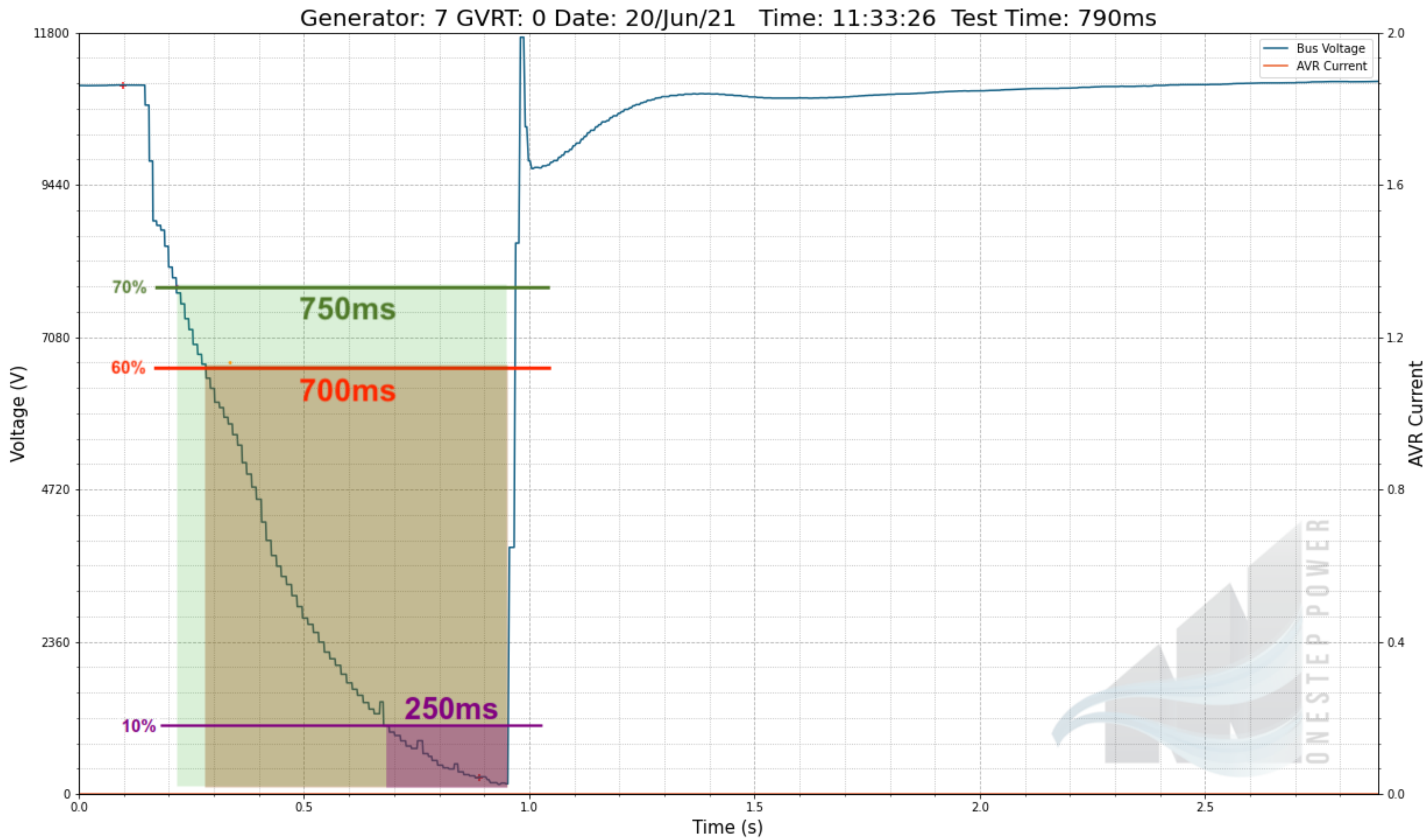


Fig. 14. Voltage response of a bus when a ZeroDip test is performed. Voltage drop to 60%, 70% and 10% of rated voltage and durations identified.

6.3.3. Combined GVRT and ZeroDip

As discussed in the previous sections both the GVRT and ZeroDip provide a single section of the voltage waveform that is required to verify fault ride through. When used in combination, it is possible to produce a voltage waveform representative of a short circuit event.

To achieve this waveform response on the network the operator selects the generators and circuit breakers that are going to be used on the system. For example in Figure 15, the following procedure is undertaken:

- Generator 2 and 5 are running and connected to bus PORT and STBD
- Bus-tie CENT - STBD is open
- Bus-tie PORT - CENT is closed
- Bus-tie STBD - PORT is closed
- ZeroDip open is connected to bus-tie PORT - CENT
- ZeroDip close is connected to bus-tie CENT - STBD
- GVRTs installed on generators on 2 and 5 are selected and ZeroDip is enabled
- A time greater than the longest duration overcurrent opening time of the bus-tie circuit breakers PORT - CENT and CENT - STBD is selected
- The test is initiated
- GVRTs 2 and 5 collapse the field of generators 2 and 5. At the same time, the ZeroDip opens bus-tie PORT - CENT
- Test time elapses
- GVRTs 2 and 5 return the fields to their respective generators and ZeroDip closes bus-tie CENT - STBD

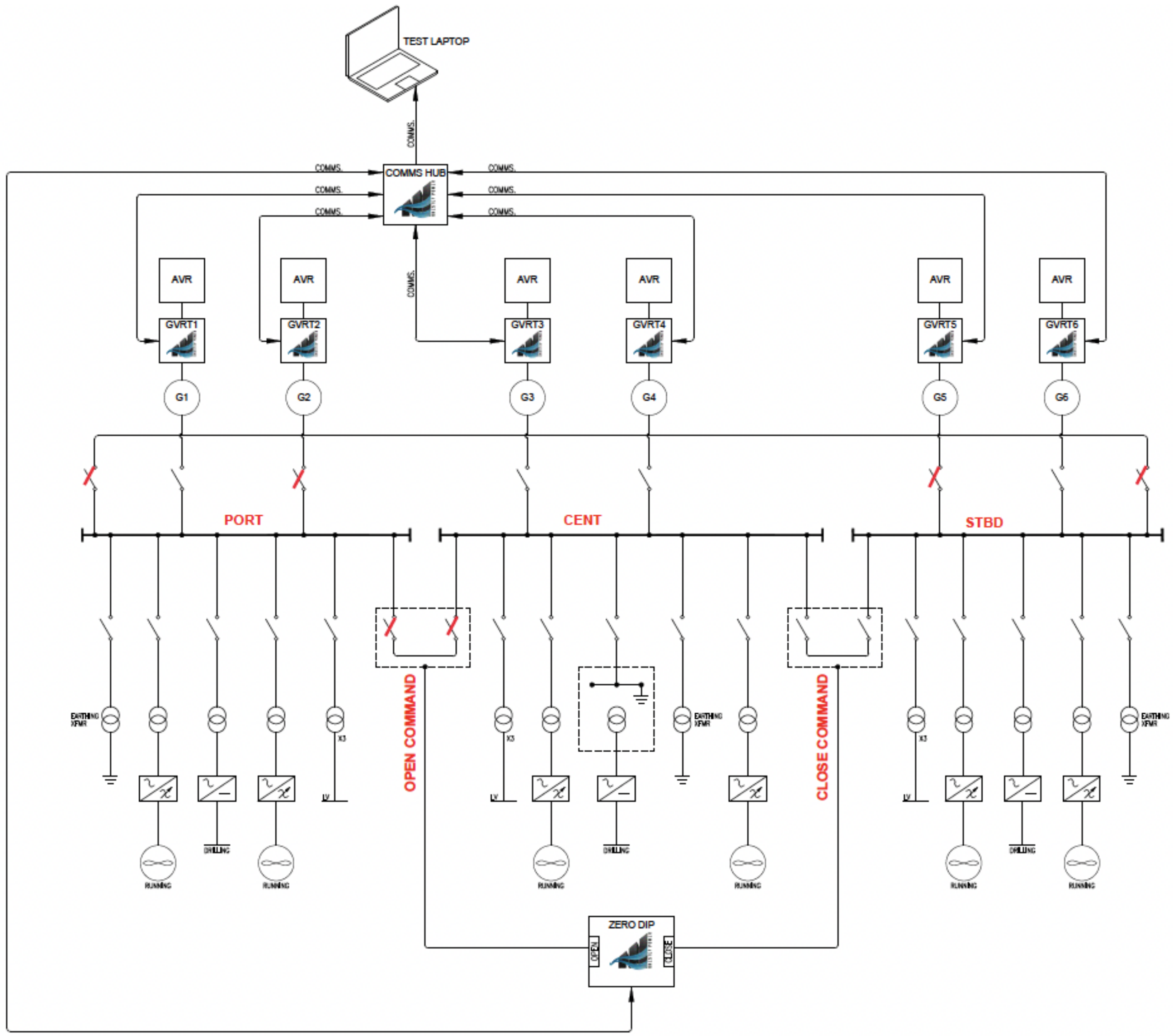


Fig. 15. Layout diagram of fault ride through test arrangement

The following graphs are the results of a test performed on a vessel using the test methodology described. The first graph shows the RMS bus voltage and the second shows the RMS voltage at one of the generator terminals and its corresponding AVR current.

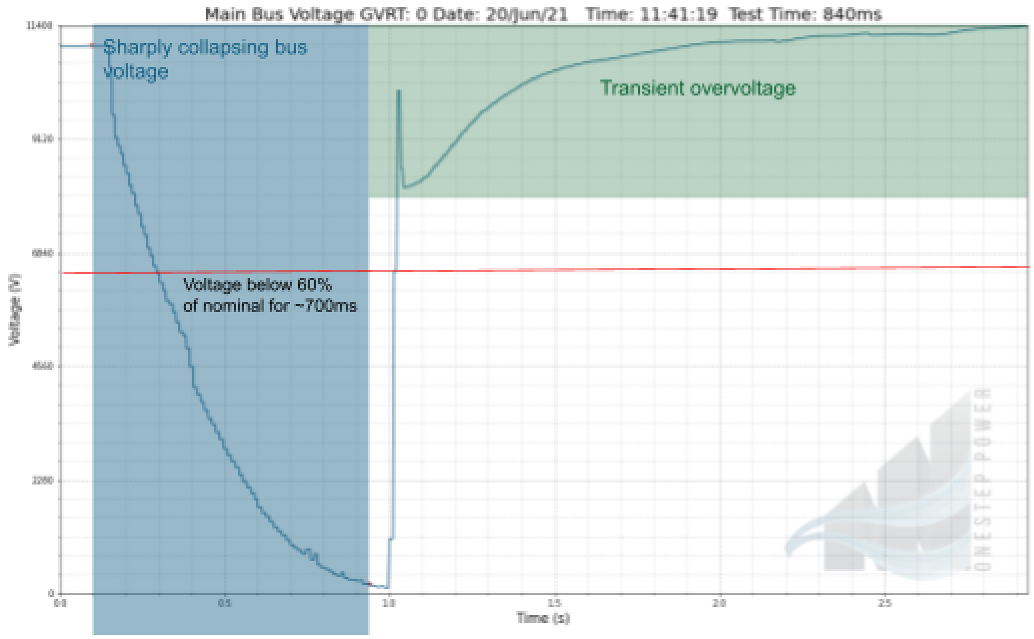


Fig. 16. Bus voltage trend during a fault ride through test performed with GVRT and ZeroDIP. Programmed test duration: 840ms.

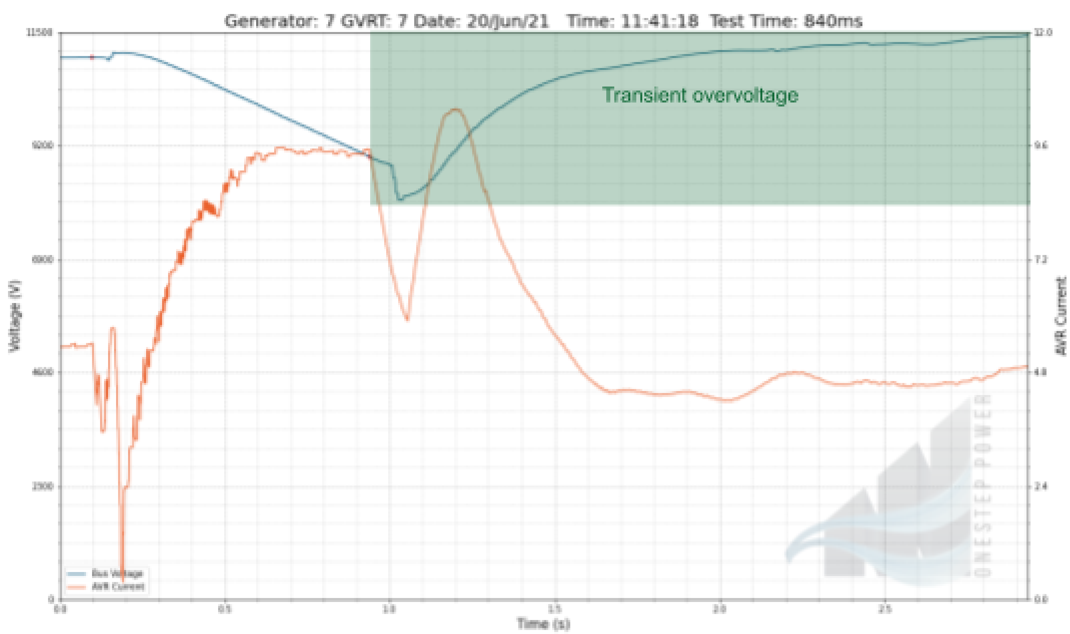


Fig. 17. Example of Generator voltage and excitation current trends during a fault ride through test performed with GVRT and ZeroDip. Programmed test duration: 840ms. Note: Gen6 and Gen7 were running and connected in parallel to the main bus during the test. Source: DP3 Drillship

The bus voltage in Figure 16 does not collapse to zero instantaneously, however it is below the 60% drop out threshold for more than the required ride-through time of the system. Note: The first time this system was tested, equipment drop-out was experienced. This is a subsequent, successful test after installation of UVT delays.

Results from a combined GVRT ZeroDip Fault Ride Through test are compared to a short circuit test provided by ABB in Figures 18 and 19. As shown in these two figures, the three main events are present, with similar characteristics for a fault in the system:

1. Pre-fault: The voltage level is at its nominal value and the system operates under normal conditions.
2. During fault: The voltage level drops below 10% of the nominal value and remains at this level for the duration of the fault
3. Post-fault: as the fault is cleared/isolated by the system protection devices, an over-voltage can be observed until it returns back to the nominal value.

The sequence of events is the same as well as the behavior of the system for faulted conditions. However, since these are two different systems under consideration, the transients, time constants and voltage drop rate can be different.

To support this equivalence further, an instantaneous plot of OneStep's Fault Ride Through protocol is compared in figure 21 with that provided in TECHOP (D-07 - Rev1 - Jan21) shown in figure 20. Again, the three main events can be observed, with time characteristics specific to the system under test.

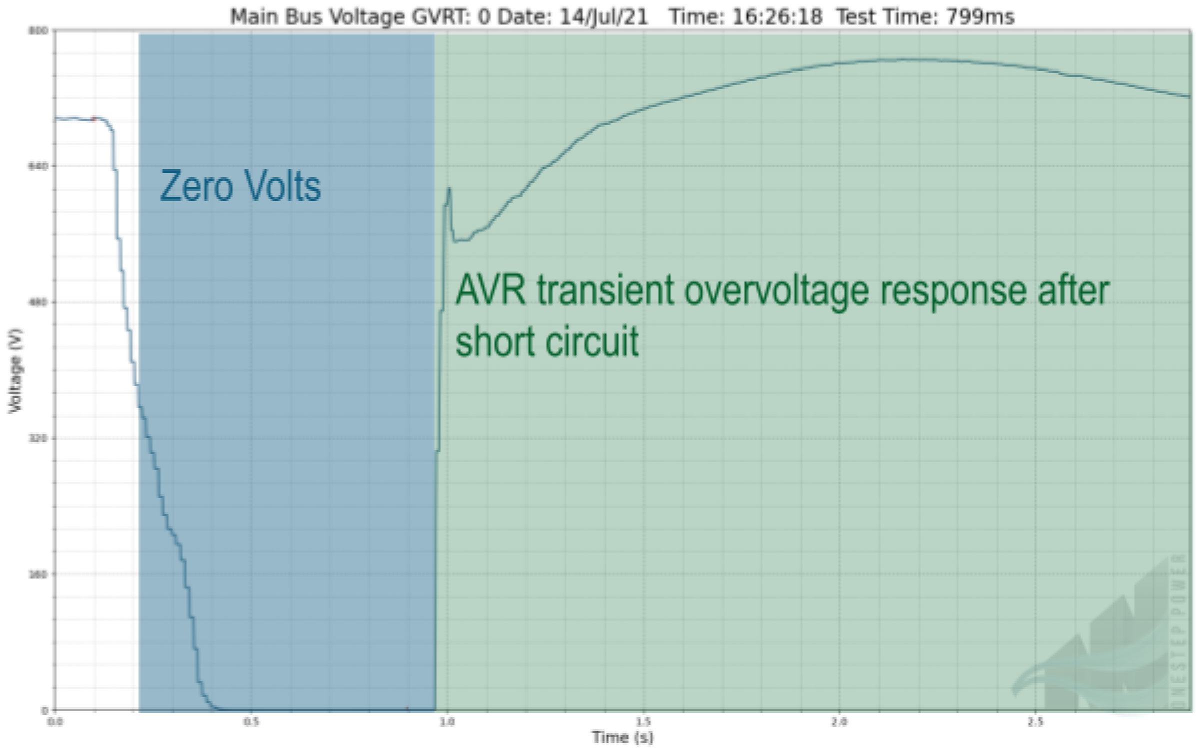


Fig. 18. Actual test result from GVRT and ZeroDIP Fault Ride through testing. Main bus voltage during 800ms fault ride through test.

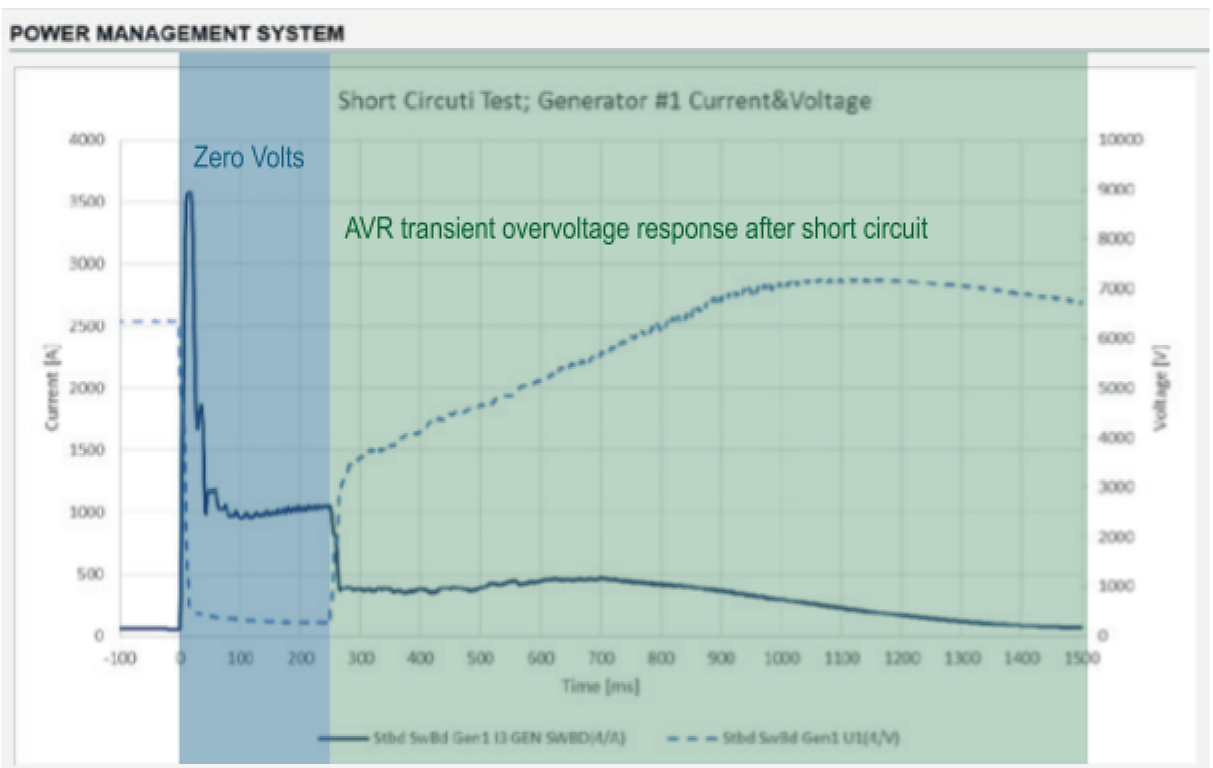


Fig. 19. Example of voltage and current trends during a short circuit test. Source: ABB[27]

[27] ABB (2017) Advanced Power Systems: Short circuit testing HV Power Systems

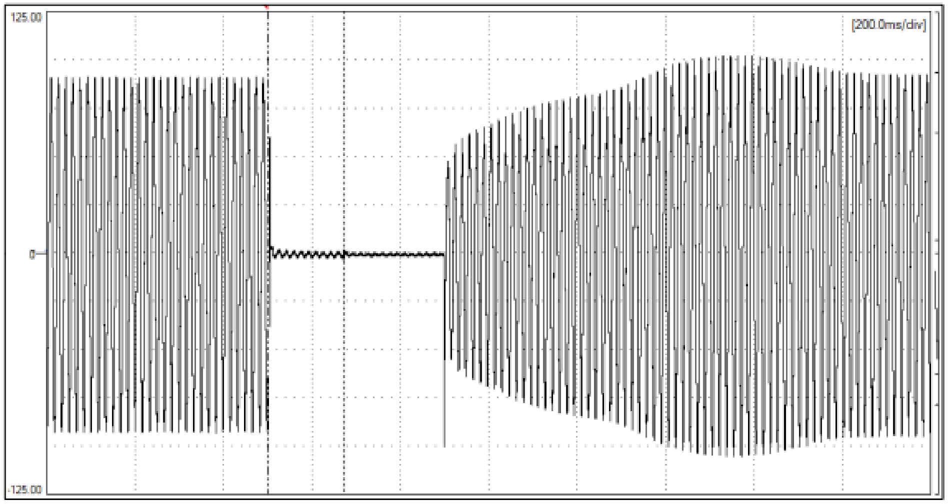


Fig. 20. Bus Voltage Before, During and After Application of Test Fault. Source: MTS TECHOP D-07

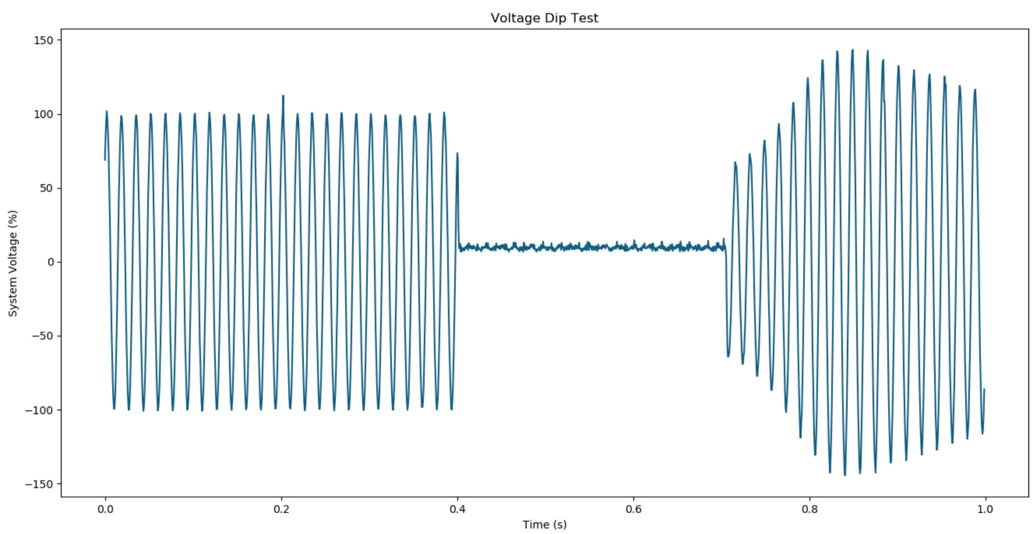


Fig. 21. Bus Voltage during combined GVRT and ZeroDip test for 300ms duration - not RMS. Source: OneStep Power Generator Facility.

6.3.4. GVRT and ZeroDip for Troubleshooting

GVRT and ZeroDip removes the risks, time constraints and costs associated with re-testing and provides a highly versatile troubleshooting aid. For example, in the case of a failed ride through test, over twenty additional tests were conducted on a network in different locations in the span of 6 hours to identify the exact cause of a failed ride through test.

6.4. Overview of Verifications Required for Short Circuits

The following table is a generalized description of required verification for correct isolation of short circuit faults. Overcurrent protection is normally instituted as the backup protection while differential protection, earth fault protections and specialised protections such as segment protection are often the primary protections for shorts on a bus section. Verification of individual protections requires an understanding of the particular facility and development of a holistic verification list. While not being exhaustive for all protections, this table covers the main concerns:

Verification Required	Short Circuit Test	OneStep's Fault Ride Through	Other Testing Methodology
Current detection and correct CTs and Interconnect wiring	Along fault path and for protections being tested	Does not validate	Primary Injection - All CTs and interconnects
Correct operation of protections	Along fault path and for protections being tested	Does not validate	Primary and Secondary injection - All protections
Generator short circuit capability	Generators used for testing	Does not validate	FAT testing of all generators. All Marine generators are required by regulation to provide 3 x I_n
Voltage waveform ride through	All buses if TECHOP D-07 Section 8.6.6 is adhered to. Only verifies network configurations tested.	All buses and main configurations	
AVR Stability	Generators used for testing	All AVRs	
AVR Boost	Generators used for testing	All AVRs	Testing during commissioning
Speed controller stability	Generators used for testing	Partial validation with load transients initiated by ZeroDip	High load step testing application in excess of 80% and rejection at 100% or as close as possible

This table demonstrates it is possible to validate all outcomes of a live short circuit with alternative methods.

6.5. Further Discussion on ZeroDip Waveforms

6.5.1. Definition of Voltage Dip

IEEE Std 1159-1995 and EN 50160 address different events in a typical power system. The voltage dip, or voltage sag as defined by IEEE Std 1159-1995, and the highlighted sections, “Momentary” and “Temporary” events, are associated with what is commonly known as short circuit.

Standard	Definition	Magnitude	Duration	Applicability
EN 50160	Short interruption	< 1%	Up to 3min	LV and MV (Up to 35kV)
IEEE Std 1159-1995	Momentary interruption	< 10%	0.5 cycles to 3 sec	LV, MV, HV
IEEE Std 1250-1995	Instantaneous interruption	Complete Loss of voltage	0.5 cycles to 0.5 sec	LV, MV, HV
	Momentary interruption		0.5 sec to 2 sec	LV, MV, HV

Figure 22 provides a graphical representation of the table above, describing the voltage amplitude and duration for events in the power system. It can be seen from the IEEE standards that the fall time of the voltage is not considered in the definition of a short circuit waveform.

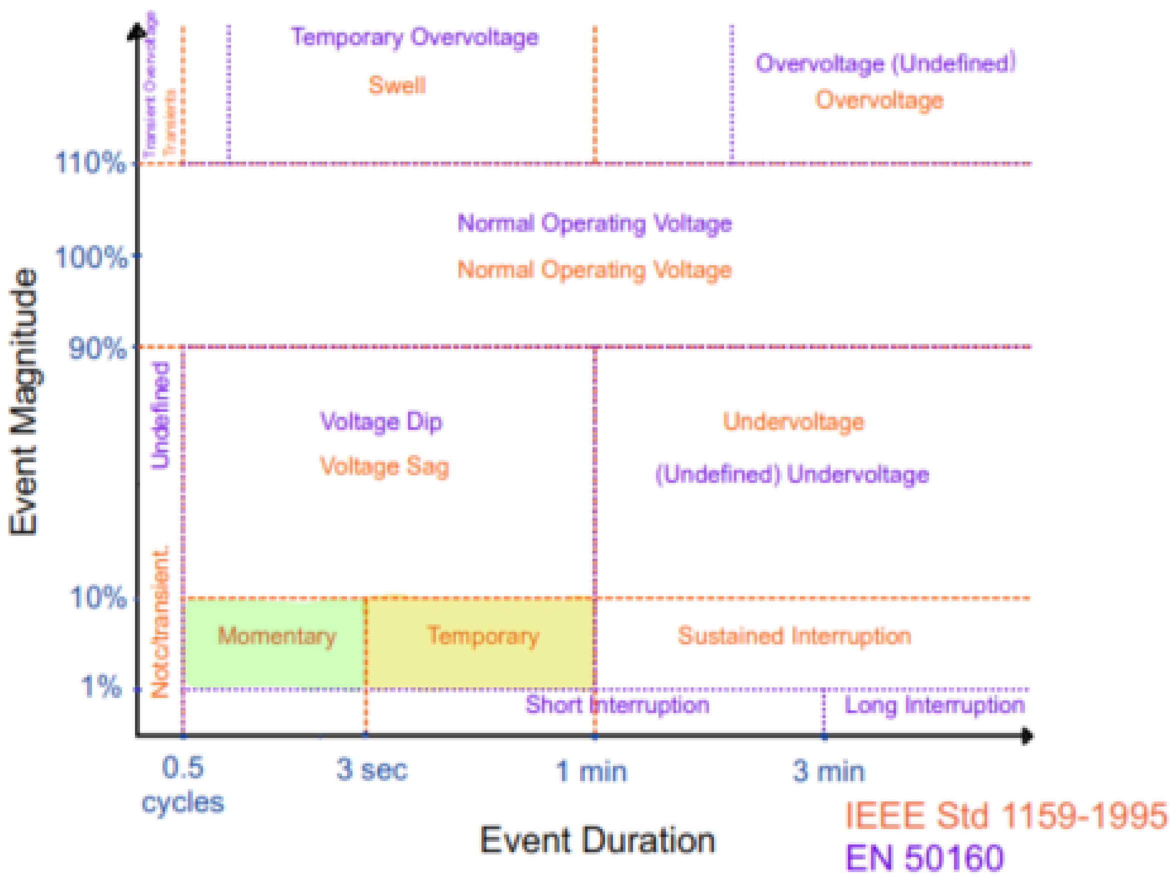


Fig. 22. Definition of voltage magnitude events based on IEEE standards[28][29].

[28] M. H. J. Bollen, *Understanding Power Quality Problems: Voltage Sags and Interruptions*. Wiley-IEEE Press, 2000.
[29] “Voltage characteristics of electricity supplied by public distribution systems”, doi: 10.3403/00567997.

Extensive studies into the properties and effects of voltage dips and sags on electrical equipment has been conducted by groups such as Conseil International des Grands Réseaux Électriques (French: International Council for Large Electric Systems; CIGRE), Information Technology Council (ITIC), Semiconductor Equipment and Materials International (SEMI) and other international power standards organizations. Review of the multiple studies from these organizations show that the two biggest factors that affect a system's ability to survive a voltage dip event are the magnitude of the dip and the duration of the dip.

The CIGRE/CIRED/UIE Joint Working Group C4.110 Voltage Dip Immunity of Equipment and Installations[30] is an extensive study into voltage dip effects, costs and classifications on all types of electrical equipment. The study used statistical analysis, data modeling, and real world fault event analysis. This data is directly relevant to any power system, including vessels. The following is extracted from the 250 page study which should be reviewed in its entirety as a thorough analysis of voltage dip immunity in electrical systems.

CIGRE/CIRED/UIE(2010) defines a typical voltage dip as being composed of five components:

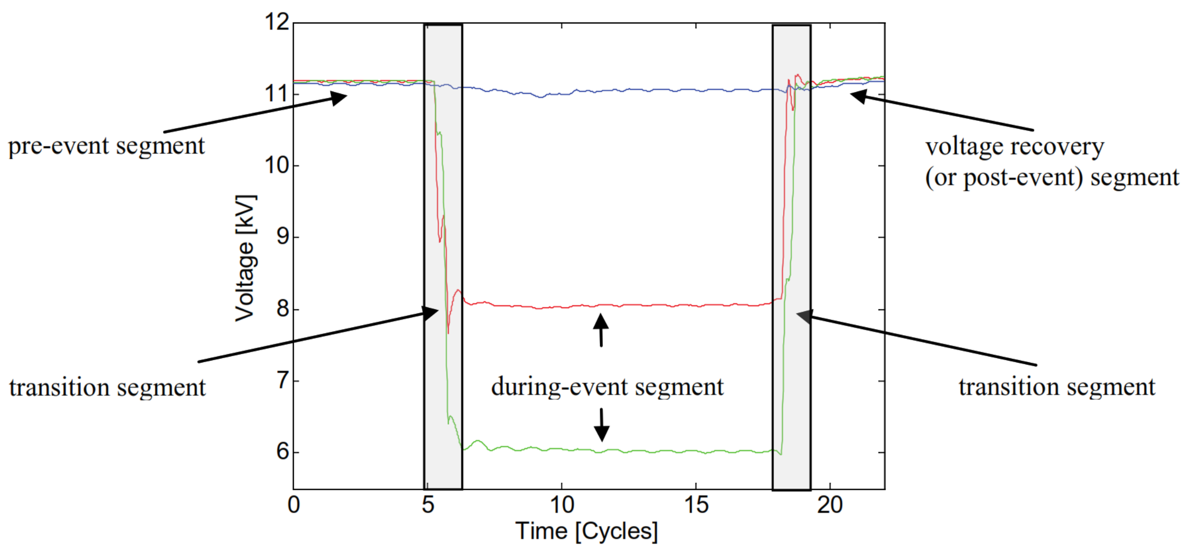


Figure 2-2 Typical voltage dip, with indicated "event segments" and "transition segments".

Fig. 23. Source: CIGRE/CIRED/UIE(2010)

> "The description of voltage dip recording in Figure 2-1 and Figure 2-2 is a combination of five different "segments":
>
> 1. The "pre-event segment", with balanced voltages of about nominal magnitude.
> 2. The first "transition segment", during which the voltages rather abruptly change from being three-phase balanced and having about nominal magnitude to being unbalanced and with lower than nominal magnitude. For fault-caused dips, the first transition segment includes the instant of fault initiation.

30 CIGRE/CIRED/UIE Joint Working Group (2010) C4.110 Voltage Dip Immunity of Equipment and Installations accessed 19 Aug 2022 http://www.uie.org/sites/default/files/CIGRE%20TB412%20voltage%20dip%20immunity%20of%20equipment%20and%20installations.pdf

3. The “during-event segment”, with, in the most general case, unbalanced voltages of lower than nominal magnitudes.
4. The second “transition segment”, during which the voltages rather abruptly change back to being more or less balanced and of more or less nominal magnitude. For the fault-caused dips, like the one shown in the Figure 2.2, the second transition segment includes the instant of fault clearing.
5. The “voltage recovery segment”, during which the voltages are balanced and with close to nominal magnitude, but they may show a trend towards a steady state.” CIGRE/CIRED/UIE(2010

The study looks at multiple electrical systems including both three and single phase AC systems. CIGRE/CIRED/UIE(2010) classifies three phase voltage dips 3 ways:

> “In its basic form, the classification distinguishes between the three general types of voltage dips that may occur at the terminals of sensitive equipment.
>
> - Dip Type III is a drop in voltage magnitude that is equal for the three voltages.
> - Dip Type II is a drop in voltage magnitude that takes place mainly in one of the phase-to-phase voltages.
> - Dip Type I is a drop in voltage that takes place mainly in one of the phase-to-ground voltages.” CIGRE/CIRED/UIE(2010)

Further to this, the mathematical equations in figure 24 were given to describe the instantaneous voltages at the terminals of equipment and were utilised in the analysis performed in the CIGRE/CIRED/UIE(2010) study.

$\overline{U}_a = \overline{V}$ $\overline{U}_b = -\frac{1}{2}\overline{V} - \frac{1}{2}j\overline{V}\sqrt{3}$ $\overline{U}_c = -\frac{1}{2}\overline{V} + \frac{1}{2}j\overline{V}\sqrt{3}$ Type III	$\overline{U}_a = \overline{E}$ $\overline{U}_b = -\frac{1}{2}\overline{E} - \frac{1}{2}j\overline{V}\sqrt{3}$ $\overline{U}_c = -\frac{1}{2}\overline{E} + \frac{1}{2}j\overline{V}\sqrt{3}$ Type II	$\overline{U}_a = \overline{V}$ $\overline{U}_b = -\frac{1}{2}\overline{V} - \frac{1}{2}j\overline{E}\sqrt{3}$ $\overline{U}_c = -\frac{1}{2}\overline{V} + \frac{1}{2}j\overline{E}\sqrt{3}$ Type I

Figure 2-17. Mathematical expressions for different types of voltage dips due to faults that may occur in a three-phase system. $\overline{E}$ is the pre-event voltage; $\overline{V}$ is the “characteristic voltage” of the dip.

Fig. 24. Source: CIGRE/CIRED/UIE(2010)

6.5.2. Compare waveforms Zerodip vs live short circuit

OneStep Power's ZeroDip test protocol provides a waveform which fits into the referenced document's definition of a voltage dip as associated with a three-phase short circuit. While the wave form does conform to the definition, it is noted that the first transition period is extended and the rate of change of voltage is less than that which would be experienced in a short circuit.

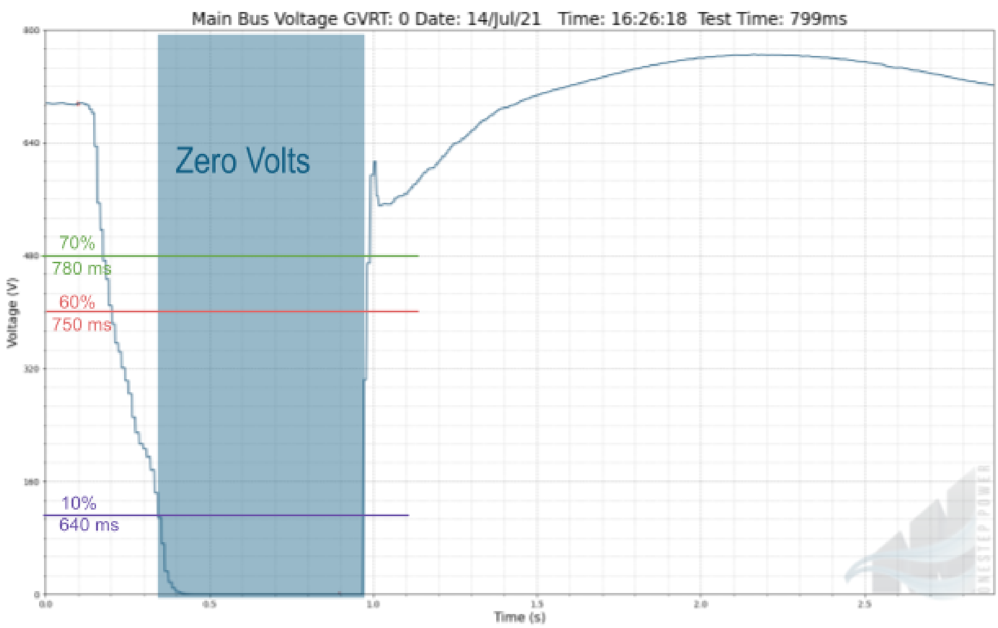


Fig. 25. Sample of testing using ZeroDip on Main Bus. Source: DP2 vessel

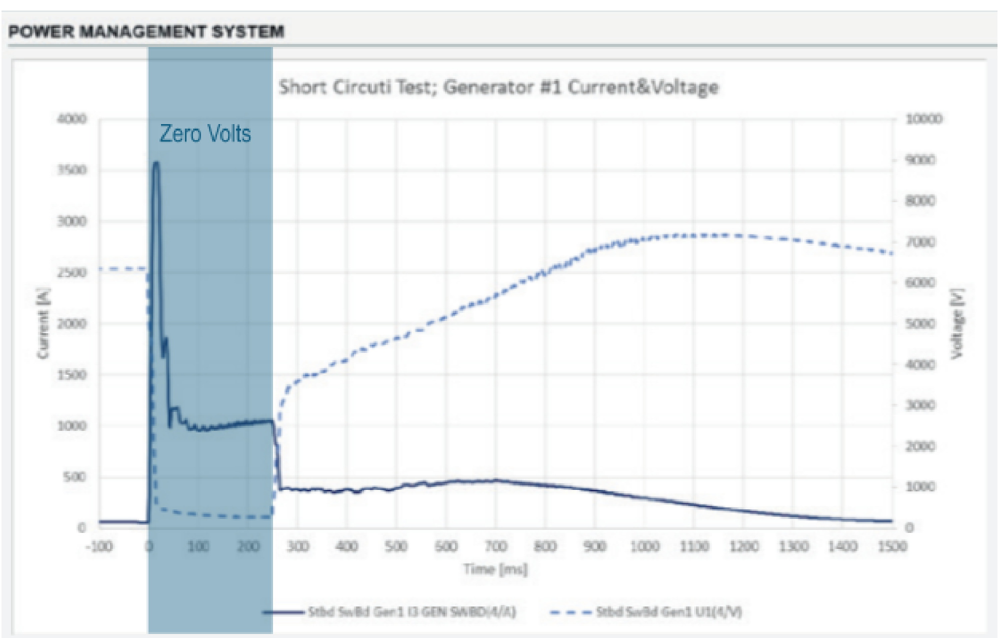


Fig. 26. Representative Short Circuit result from OEM HV system test. Source: ABB[31]

[31] ABB Advanced Power Systems (2017) Short circuit testing HV Power Systems. Accessed 26 October 2021 https://search.abb.com/library/Download.aspx?DocumentID=3AJM005000-0085&LanguageCode=en&DocumentPartId=&Action=Launch

6.5.3. Explanation of variations

The decreased rate-of-change of voltage of the ZeroDip waveform is the result of using an interrupt of source style fault instead of a high current short circuit. The reason a short circuit results in a faster decline of voltage is that the low impedance of the fault causes high current leading to a voltage dip and consumes stored energy in the system. Instead, ZeroDip removes the source for a short period but allows the stored energy in equipment such as electric motors, transformers, capacitor banks, etc, to feed back into the system. This behaviour is described in IEEE 1159-2019.

> "An interruption occurs when the supply voltage or load current decreases to less than 0.1 pu for a period of time not exceeding 1 min. Interruptions can be the result of power system faults, equipment failures, and control malfunctions. The interruptions are measured by their duration since the voltage magnitude is always less than 10% of nominal. The duration of an interruption due to a fault on the utility system is determined by utility protective devices and the particular event that is causing the fault. The duration of an interruption due to equipment malfunctions or loose connections can be irregular.
>
> [Figure 27] shows a momentary interruption during which voltage drops to zero for about 1.7 s. Note that the upper plot depicts the rms variation of the entire event over a range of approximately 2.5 s, whereas the lower trace depicts the instantaneous voltage during the initiation of the event only. ***Furthermore, notice from the waveshape plot of this event, the instantaneous voltage might not drop to zero immediately upon interruption of the source voltage. In this example, the residual voltage is due to the back-electromotive-force effect of induction motors on the interrupted circuit.****"* IEEE 1159-2019[32] [Emphasis added]

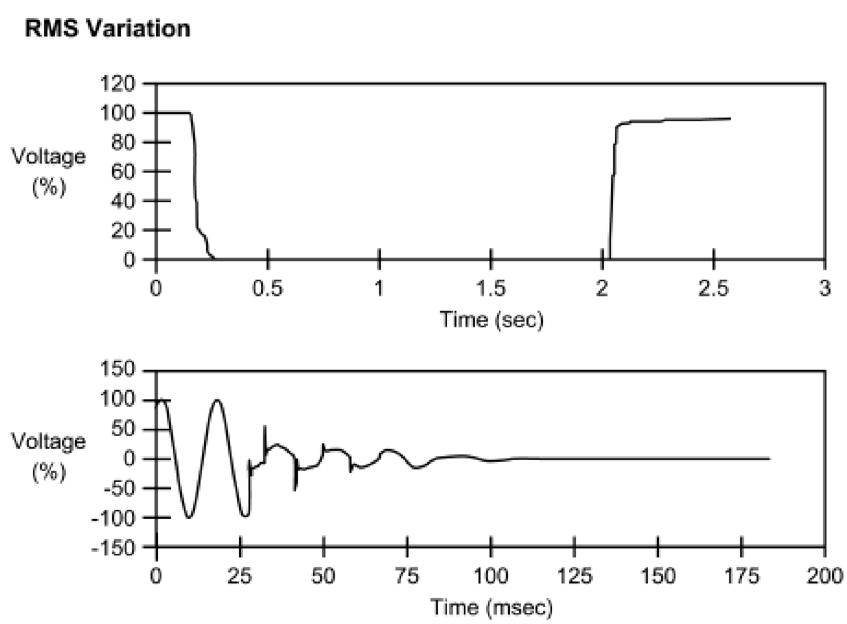


Fig. 27. Momentary interruption during which voltage drops to zero for about 1.7 s. Source: IEEE 1159-2019

[32] IEEE (2019) IEEE 1159-2019 Recommended Practice For Monitoring Electric Power Quality.

6.5.4. Analysis of variation impact

IEEE standards categorize a short circuit by:

1. IEEE Std 1159-1995: a voltage drop of ≥90% for a duration of 0.5 cycles (8.33 ms) to 3 s.
2. IEEE Std 1250-1995: a “complete loss of voltage”, for a duration between 0.5 s to 2 s.

It can be concluded that for a short circuit definition the two important criteria, according to IEEE, are the magnitude of the voltage drop and the duration of the voltage at the reduced level. McGranaghan (2006)[33] advises on what aspects of a voltage dip event have an impact on the associated equipment:

> “According to the book Electrical Power Systems Quality (ISBN 0-07-138622-X), there are three categories of equipment sensitivity:
>
> 1. *Equipment sensitive only to the magnitude of a voltage sag*. Here, the important characteristic is the sensitivity to the minimum (or maximum) voltage magnitude experienced during a sag (or swell), with the duration of the disturbance usually being of secondary importance. Devices in this category include undervoltage relays, process controls, motor drive controls, and many types of automated machines, such as semiconductor manufacturing equipment.
> 2. *Equipment sensitive to both magnitude and duration of voltage sag*. The important characteristic of this group is the sensitivity to the duration of which the rms voltage is below a specified threshold where the equipment trips. This group includes almost all equipment using electronic power supplies.
> 3. *Equipment sensitive to characteristics other than magnitude and duration*. Some devices are affected by other sag characteristics, such as phase unbalance during a sag event, the point-in-the-wave at which the sag is initiated, or any transient oscillations occurring during the disturbance.” (Emphasis McGranagan’s)

McGranaghan’s work does not detail the impact of the third style of characteristic, however the CIGRE/CIRED/UIE(2010) study did assess the impacts of these other characteristics, and through analysis, found that the biggest impacts to the ride through of equipment were:

- The magnitude of the dip in the event section
- The duration of the dip in the event section

The research also found that the following had less of an impact on the response of the system:

- Point-on-wave (at what angle of the supply waveform the fault is initiated)
- Phase-angle jump (The phase shift caused by a sudden change of reactive load when a fault occurs)
- The rate-of-change of voltage for the initial transition
- The rate-of-change of voltage for the recovery transition

[33] McGranaghan, M (2006) Dealing with Voltage Sags in Your Facility accessed 19 Aug 2022 https://www.ecmweb.com/content/article/20890777/dealing-with-voltage-sags-in-your-facility

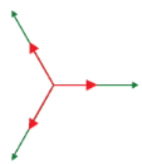
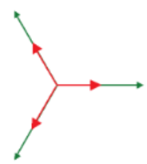
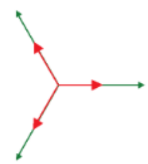
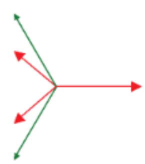
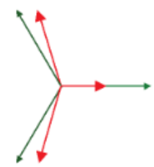
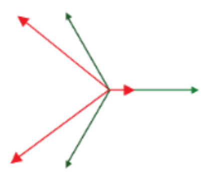
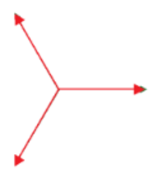
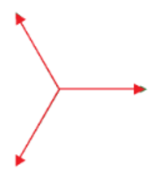
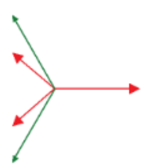
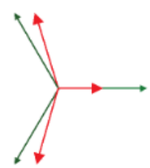
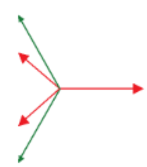
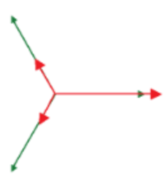
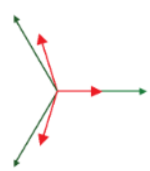
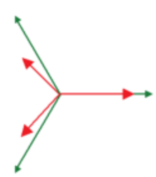
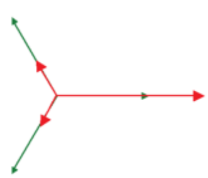
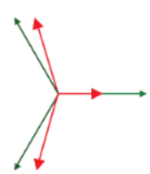
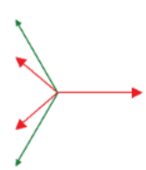
Of the second list of factors, point-on-wave and phase-angle jump were considered to have the biggest impact on system ride through however the following statement was made in relation to further testing of these characteristics:

> "The Working Group recommends that compliance testing includes only two dip characteristics: residual voltage (magnitude) and duration. Based on the presently available knowledge, the Working Group does not see sufficient justification to perform additional tests covering characteristics such as phase-angle jump and point-on-wave." CIGRE/CIRED/UIE(2010)

In addition to the impacts of the waveform on specific equipment, CIGRE also studied how the fault would propagate through a system, and if this would have detrimental effects on ride through capability. The CIGRE/CIRED/UIE(2010) study found three phase voltage dips propagate through a distribution network without undergoing significant change to the characteristics of the waveforms of the fault. The following extract, including the figure over page, describes the changes to the voltage vectors in a distribution network.

> "*2.9.1 Changes in event segments* due to transformer winding connections
> Different transformer winding/earthing connections change the magnitudes and phase angles of the phase-to-ground and phase-to-phase voltages. A distinction can be made, in this context, between the three general types of transformers:
>
> - Transformers that do not have any impact on the voltages; these are only Yy transformers, grounded/earthed on both sides.
> - Transformers that remove the zero-sequence voltage in part or completely. The zero-sequence voltage is completely removed by, for example, a Dd transformer, or by a Yy transformer that is not grounded. A three-winding Yyd transformer removes only a part of the zero-sequence voltage.
> - Transformers that change phase-to-phase voltages into phase-to-neutral voltages (and the other way around), and also remove the zero-sequence voltage.
>
> The best-known example is the Dy transformer.
>
> The table below illustrates the changes in voltage magnitudes and phase angles of the three phase-to-neutral voltages for dips due to different fault types after propagating through one and two Dy transformers. The following comments should be made for interpreting the table.
>
> - The (green) phasors with smaller arrowheads indicate the pre-fault phase-to ground voltages; the (red) phasors with bigger arrowheads indicate the during-fault phase-to-ground voltages.
> - For all diagrams, the phasor in one of the phases is given in the horizontal direction. Any phase shift between primary and secondary side of a transformer is not considered here.
> - Any transformer that changes phase-to-phase voltages into phase-to-neutral voltages (i.e. the third type in the above list) will change the dip type in the same way as a Dy-transformer.
> - The impact of removing the zero-sequence voltage is the same as the impact of two Dy transformers.

- The impact of changing from phase-to-ground measurements to phase-to-phase measurements is the same as the impact of a Dy transformer. "

Type of fault	Dip at faulted voltage level	Dip after one Dy transformer	Dip after two Dy transformers
Three-phase			
Single-phase in a solidly-grounded network			
Single-phase in a non-solidly-grounded network			
Two-phase			
Two-phase-to-ground in a solidly-grounded network			
Two-phase-to-ground in a non-solidly grounded network			

A dip due to a three-phase fault does not change at all due to the transformers: a voltage drop in three phases remains a voltage drop in three phases. However, a voltage drop in one or two phases, due to an asymmetrical fault, changes character (i.e. dip type change) when transferring through a Dy transformer." CIGRE/CIRED/UIE(2010)

CIGRE says not only is the type of sensitivity important, but you should also consider what happens on a network with transformers. The study shows that on a three phase dip, the transformers have no impact on the dip, however on the other faults, transformers may have a significant impact.

The implication of this, is that the application of a three phase voltage dip does not suffer any changes beyond the transformer, and it can be translated to voltage dips downstream of the transformer. While not relevant to the discussion of ZeroDip waveforms, this is a good illustration of how earth faults may cause greater problems than expected, including over-voltage events.

The following quote from CIGRE/CIRED/UIE(2010) discusses the effect of harmonic components within sections of the fault waveform. While the effects were analysed as being minor and not significant enough to warrant further analysis and testing, it was noted that premature tripping could occur with some equipment due to incorrect firing times in circuits using phase lock loop, such as SCR drives and switch mode power supplies not using closed loop control. The implication here is that a slower decay, containing harmonics due to transformer and motor components, are more likely to cause equipment to trip offline, than a sharp decline. Therefore, although it is highly unlikely that any impact would be observed, the outcome of a decayed waveform would be an equipment tripping offline, not equipment riding through, essentially, a false fail result, not a false pass result.

> "In some cases, the waveform distortion during an event segment is significantly higher than during the normal/pre-event operation. This concerns mainly events associated with transformer saturation, but may be also related to the occurrence of different types of transients visibly imposed on voltage waveform, featuring, for example, multiple voltage waveform zero-crossings, which may cause malfunction of some electronic equipment (e.g. those using phase-locked loop, PLL, circuits)." CIGRE/CIRED/UIE(2010)

Finally, MTS TECHOP-D07 (2021) requires only the attributes of magnitude and duration:

> "5.2 ATTRIBUTES TO BE PROVEN
> 5.2.1 Power system attributes which should be proven by a combination of computer simulation and testing to demonstrate fault ride-through capability are:
>
> 1. The voltage dip ride-through capability of the entire plant is to be proven. This is most effectively done by testing. This type of test will help to reveal hidden failures, incorrect settings and design deficiencies associated with voltage dip ride through. ***The voltage dip created during a properly executed fault ride-through test is representative of the voltage dip with the greatest magnitude and duration that is expected.***" (MTS TECHOP-D07 2021, Emphasis added)

All the OneStep Power generated results presented adhere to the two important factors of short circuit, and the voltage drop slope is a function of the system under test. OneStep has observed the following failures during ZeroDip testing:

- Thruster drive failures (under voltage trip)
- Thruster drive failures (unable to ride through at operational speed due to kinetic ride through arrangement)
- Industrial mission drive failures (under voltage trip)
- Loss of distribution switchboards (under voltage trip)
- Loss of switchboards on under voltage trip on systems which previously have passed "bang-bang" testing
- Loss of cooling fans & auxiliaries (drop out due to loss of control relays/contactors)

- Loss of main switchboards (drop out due to loss of control)
- Loss of main switchboards (under voltage trip)
- Loss of thruster control cabinets (Shutdown due to voltage dip as they were connected to normal supply, not UPS as required by design)

Note: These are only failures during ZeroDip testing and do not include over-voltage transient failures induced by the GVRT. The ability to induce both of these waveforms, either in combination or separately, allows OneStep Power the unique opportunity to identify the reason for failure, and to assist in troubleshooting at a much faster rate.

In conclusion, having reviewed multiple power industry resources, there is a sufficient body of evidence, including theoretical, simulated, and empirical, confirming that while there are some effects on fault ride through immunity from other factors, the majority of the impact is as a result of voltage dip magnitude and duration. This is supported by results of on-board vessel testing performed on a range of DP2 and DP3 vessels.

7. Short Circuit Calculations

The International standards guiding short circuit calculations are well-established and have been available since IEC 60363 was published in 1972. The latest standard, IEC 61363-1:1998 outlines procedures for calculating short-circuit currents that may occur on a marine or offshore AC electrical installation.

The decrement curve is an important input into short circuit studies. Studies are performed for a range of industrial applications including onshore grid applications and high-reliability micro-grids. These studies are performed using well-established standards such as IEC 61363. OneStep acknowledges that garbage in = garbage out, and there must be assurances of the decrement curves and other inputs into the study.

A marine generator's decrement curve must be calculated using the appropriate standards. Type testing of generators to confirm the decrement curves is acceptable by 2021 DNV rules[34] and physical testing is "not required" by ABS 2021 rules[35]. It is assumed that class societies accept only well-documented methodologies for the calculation of the decrement curve. Standards such as IEC 61363-1:1998 describe the protocols and are considered to be within the accuracy limits required for system design.

Section 8.2 of MTS's TECHOP-D-07 (2021) reviews the short circuit current estimation methodology: "*In common with some other standards, the contribution to the overall short circuit current is approximated to be the sum of three ac currents and a dc component provided by voltages behind impedances which decay at different rates. These impedances are associated with the direct axis of the machine. The impedances for the quadrature axis are neglected to simplify the calculation but this is said to reduce accuracy by no more than 10%*."

There should be a confirmation that the inputs to the short circuit study accurately reflect the equipment installed on the vessel. The fact is there are many ways for a short circuit study to be incorrect. Competent client, third party and peer review is the only way to ensure all inputs to the simulation model are correct, and that any "lumped" loads are sufficiently defined for the protection sensitivity of the system.

DNV Class requirements for marine generators include "*a) Generally, AC synchronous generators, with their excitation systems, shall, under steady short circuit condition, be capable of maintaining, without sustaining any damage, its short circuit current, which shall be at least three (3) times the rated full load current, for a duration of at least 2 s. (IEC 60092-301 modified clause 4.2.3)*" [36]

As part of the OneStep Power Comprehensive Testing Protocol, our power engineering team reviews the short circuit study and protection coordination studies for correct assumptions and inputs. OneStep Power requires the following protective relay short circuit settings for closed, single bus arrangements[37]:

- The short time / instantaneous short circuit protection on the bus-ties needs to be set at a minimum of 10% below the maximum calculated short circuit current for each bus.
- The short time / instantaneous short circuit protection limit must also be set below the maximum cable current indicated in the cable damage curve.

[34] DNV (2021) DNV-RU-SHIP Pt.4 Ch.8. July 2021, Electrical installations
[35] Rules for building and classing marine vessels — ABS Rules Pt.4 Ch.8. July 2021
[36] DNV (2021) DNV-RU-SHIP Pt.4 Ch.8. Section 5, 2.3.1. July 2021
[37] Note: For ring-bus arrangements, the protections and the calculations are more complex, and are not the subject of this paper.

- The long time, or secondary bus-tie protection needs to be set at or below three times the rated current of the smallest single generator which will be connected to the bus during operation.

The duration of the fault ride through test must be for the length of the longest short circuit protection, to ensure activation of the protections.

Based on these conditions, the decrement curve should not play a significant role in the coordination of the protections. The decrement curve's main purpose is to ensure that the current capabilities of the switchboard and bus bars can withstand the maximum theoretical fault current.

8. Pole Slip

Pole slip, also known as out of step, occurs when at least one of the rotating machines connected to the network breaks the magnetic linkages between the rotor and stator. This linkage break occurs when the magnetic rotational speed of the network (bus frequency) is different to the mechanical rotational speed of the prime mover and the force required to maintain or close this difference is greater than the force provided by the magnetic linkages in the machine. Instances that can lead to the loss of magnetic coupling include:

- sudden and/or extreme changes of frequency on the network
- sudden and extreme changes in load
- sudden and/or extreme changes of the prime mover rotational velocity
- loss of or low excitation current of the generator
- sudden phase shifts due to reactance change on long line networks e.g. uncontrolled switching
- a combination of the above factors

While out of step protections do exist they are generally not implemented on vessels as the generators are in close proximity. This close proximity of generators on vessels results in low inductances and minimal phase shifts between machines when compared to large land networks where out of step is of greater concern.

The greatest chance of a pole slip occurring on a vessel power system is at the application of a fault or the clearing of a fault; when the system is undergoing its largest transients and magnetic linkages may be weak. To prevent pole slip from occurring at these times, protections such as under-excitation limiters and excitation boost circuits are implemented. These limits and circuits are used to ensure that the magnetic linkages are maintained at a level that should eliminate pole slip occurring. In addition to the limits on low excitation, Volt Ampere Reactive (VAR) protections should be in place so that if a generator exits its stability limits on the Direct and Quadrature (DQ) curves, it is removed from the network.

Loss of synchronisation may be caused by severe mechanical failure in generator prime movers:

- Broken con rod
- Big end or little end bearing failure
- Other mechanical failures

Mechanical failures of this magnitude will result in the machine coming to a very sudden stop, and a fault current level similar to a short circuit, with the added disturbance of a load step due to loss of power source. This type of failure cannot be prevented therefore the power plant must be able to survive its voltage and current effects until the faulty machine can be isolated to one redundancy group. The short circuit testing program shall be designed to provide verification of the ride through capability of the system during this failure event.

Testing with the GVRT and ZeroDip can confirm if machines on a network are “stiff” enough to avoid pole slip. The GVRT collapses the field current and thus causes drastic reduction in internal amature voltage E_A and rotor current I_r. The test devices also induce fast shifts in load by opening and closing breakers; creating the components that lead to pole slip. For this reason, the GVRT and ZeroDip switching times begin low, around 200 ms, and are slowly increased, to 800 ms or greater. If any unusual network or machine disturbances not related to the standard voltage responses are noted, the testing is stopped and the reason for the non-standard responses are investigated. At the time of writing no power systems tested using the GVRT and ZeroDip have exhibited signs of pole slip, so no examples can be given. Figure 28 illustrates the voltage and current responses expected prior to a pole slip failure:

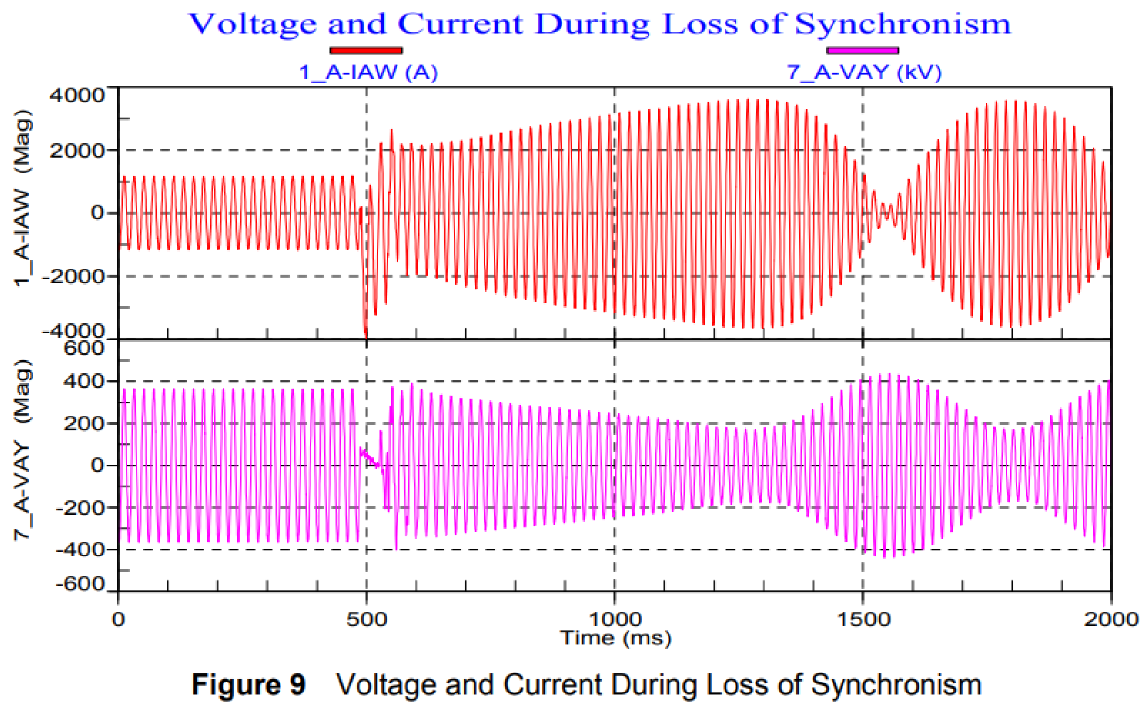


Fig. 28. Example of network response prior to pole slip fault. (Tziouvaras & Hou, 2003)[38]

Figure 28 is an extreme example that demonstrates the worst case outcome with an actual pole slip failure. In cases that are leading to pole slip, the voltage on the main bus will exhibit a reduction as the current increases, this may be in a cyclic fashion with the oscillations reducing over time.

Proving the system is capable of riding through these styles of transients is required for closed bus operation.

8.1.1. Testing for the Worst Case Failure

The current associated with pole slip may be considered to be similar to a short circuit on the main bus, which can be validated using primary injection and fault ride through.

[38] Tziouvaras & Hou (2003) Out-of-step Protection Fundamentals and Advancements, Accessed 28 October 2021 https://cdn.selinc.com/assets/Literature/Publications/Technical%20Papers/6163.pdf?v=20151125-191441#:~:text=Out%2Dof%2Dstep%20protection%20functions,step%20change%20during%20a%20fault

9. Crash Synchronization

Crash synchronisation, also known as “out of phase synchronization”, refers to generators being connected before synchronization has been completed, or a generator that is either stopped or running at low speed being closed onto the bus. The currents observed during a crash synchronization are comparable to the currents that are seen during a three phase symmetrical fault however the torque on the machine may be exceeded by 2 to 3 times and lead to shaft failure and stator winding damage that is not normally associated with excessive currents.

“As a consequence of shaft failures in two units in a Consumers Power gas turbine installation, a computer study was Performed to determine the torques In the turbine-generator shaft system during out-of-phase synchronization. Prior to this study, the possible occurrence of excessive torques in the turbine-generator shaft system without damage to the stator windings due to large currents was questioned. If the gas turbine-generator unit is designed to sustain the stator currents and the instantaneous shaft torques resulting from a three phase short circuit at the machine terminals, then the results of this investigation revealed that during out-of-phase synchronization the design torques may be exceeded by 2 to 3 times without exceeding the amplitude of the short circuit stator currents. From this it seems reasonable to infer that shaft failure could occur during out-of-phase synchronization without damage to stator windings due to excessive currents”[39]

There are a number of different scenarios that can lead to a crash synchronization event and each of the scenarios require different approaches to minimise the probability of an occurrence. The main events that can lead to crash synchronization include:

- Synchronizer failure
- Simultaneous connection of two generators onto the same dead bus
- Manual closure onto a live bus

9.1.1. Synchronizer failure

A synchroniser may be considered a single point of failure. This can be mitigated by the use of an additional “Sync Check Relay” installed directly prior to the closing coil of all generators and bus-ties used for connecting multiple generators to a common bus. Addition of this sync check relay increases the required failures from one to two and thus reduces the likelihood of failure. The installation of sync check relays has not been industry standard practice and therefore crash synchronization must be considered when vessels are preparing to operate in closed bus configuration.

[39] Krause, Hollopeter, Triezenberg, Rusche (1977) Shaft torques during out-of-phase synchronization, Accessed 28 October 2021 https://www.semanticscholar.org/paper/Shaft-torques-during-out-of-phase-synchronization-Krause-Hollopeter/a362f6b03d41eb2473326ee72ee791f37ac8e358

9.1.2. Simultaneous closure of generator breakers

To prevent an instance of two generators connecting to a single dead bus section at the same instant there must be a delay set in the vessel's power management system. This should be tested as part of the blackout recovery procedures with two generators on the same bus set as the first to connect.

9.1.3. Manual closure onto live bus

It is common for generators used to power main propulsion systems to have a manual closing button to allow closing a generator onto the bus in case of control system failure. This button should be fitted with a tamper resistant cover to prevent accidental closure of the breaker.

9.1.4. Testing for the Worst Case Failure

Crash Synchronization is a serious concern for the operation of safe vessels. Demonstrating the outcome of a crash synchronization event is not possible due to the destructive nature of the fault. The prevention measures may be tested: synchronisers and sync check relays must be tested for correct operation during commissioning, with recommended maintenance per OEM.

The current associated with a crash synchronization may be considered to be similar to a short circuit on the main bus, which can be validated using primary injection and fault ride through.

10. Conclusion

Verification of short circuit style faults is a complex issue and there is no single silver bullet. OneStep postulates that with the correct application of existing technologies and OneStep Power technologies it is possible to verify the correct isolation and ride through capability of a closed bus system without the application of a short circuit.

Comparative evaluation of a live short circuit voltage response versus a GVRT and ZeroDip voltage response yields minimal variation in voltage waveforms. OneStep Power has never suggested the GVRT and ZeroDip technologies alone are sufficient to demonstrate equivalent integrity. OneStep Power strongly recommends and continually promotes the use of existing methods such as primary and secondary injection and traditional DP FMEA testing.

When the methods described in this protocol are implemented in a holistic test program, the equivalent integrity of closed bus configurations on dynamically positioned vessels can be confirmed.

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Appendix A - GVRT Operational Description

At the most basic level, the theory of operation of the GVRT is that the current from the AVR is switched to a resistive inductive load and the field winding current to the generator is supplied from the GVRT. To perform rapid transient voltage testing the field has all current removed to cause the fastest collapse of the internal generator voltage E_A.

Reducing or removing a single generator's excitation current when multiple generators are connected to a network will result in that generator maintaining terminal voltage but producing less VARs, eventually consuming VARs once the magnetic field of the rotor is reduced sufficiently. To cause terminal voltage drop and hence induce bus voltage transients, it is necessary to reduce E_A on all generators connected to the network at the same time.

To ensure that the voltage transient is applied to the network, all generators connected to the network must have a GVRT installed between the AVR and the generator field windings. The GVRTs then induce the same reduction in E_A simultaneously to all connected generators. It is possible to use a single generator to cause the voltage transient on a network, this however does not provide information on how "stiff" the system is and what the reaction of generators are when multiple units are connected. Performing a GVRT test with multiple generators connected can show vital information such as the response and ability of the control system to resist faults such as pole slip caused by low excitation while transients are occurring.

11.1.1. Test Device Function

When not in test mode, the GVRT allows the field signal to pass from the AVR to the generator field normally. The AVR's feedback cycle is uninterrupted and normal operation is observed.

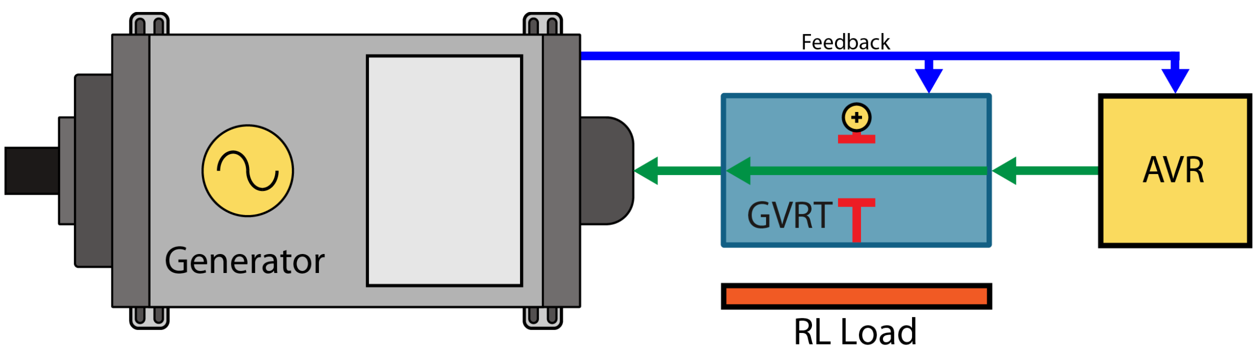

Fig. 29. GVRT arrangement - Uninterrupted AVR control

When a test is initiated, the GVRT will assume control of the field signal, sending a zero-volts signal to the generator, causing the generator field to collapse. Meanwhile, the AVR field signal will continue to be consumed by the RL load located in the GVRT. The load is used to show AVR current capability and prevent the AVR or generator from tripping on protections such as loss of field.

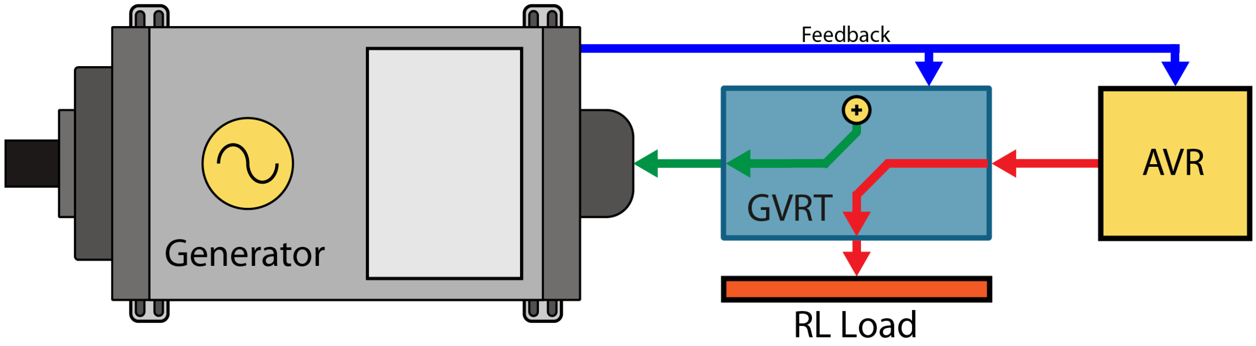

Fig. 30. GVRT arrangement - AVR to RL Load

As the field collapses, the voltage transducers in the AVR feedback loop will observe the decrease in field voltage, causing the AVR to increase the current it is sending to the "generator" (RL load). This cycle continues for the duration of the test, at which point the GVRT returns control of the field signal to the AVR. As the AVR has been driving increasing amounts of current into the RL load, return of the field to the AVR causes the field signal to be higher than required, driving the field voltage up, before correcting and resuming normal operation.

11.1.2. Connection Arrangement

To ensure that the machines all undergo the same reduction in excitation, all GVRTs are connected to a central computer using a hub and proprietary high speed full duplex network in a star configuration. To ensure high speed and synchronized operation, each GVRT has two onboard microcontrollers, one for control and DC measurement and a second dedicated to AC measurement and calculation. Two microcontrollers are used so that high overhead AC calculations do not interrupt the synchronization and timing of the tests while still allowing for real time calculation and safety features.

The GVRT is temporarily installed between the AVR and the Generator with connections made to the AVR, field windings, voltage transformers, and the measurement current transformers. It is important that the measurement transformers are used and not the protection transformers as any interruptions to the protection circuits will require a higher level of verification after testing and introduces an unnecessarily higher risk profile.

The figure following shows how temporary connections between the GVRT and generator are made:

- GVRT in series with the connections from the AVRT to the field
- GVRT in series with current transformers
- GVRT in parallel with the voltage measurements

This figure shows a connection with all three phases being measured. In many cases only "B" phase current is available at the generator terminals, the GVRT will operate correctly with single phase measurements.

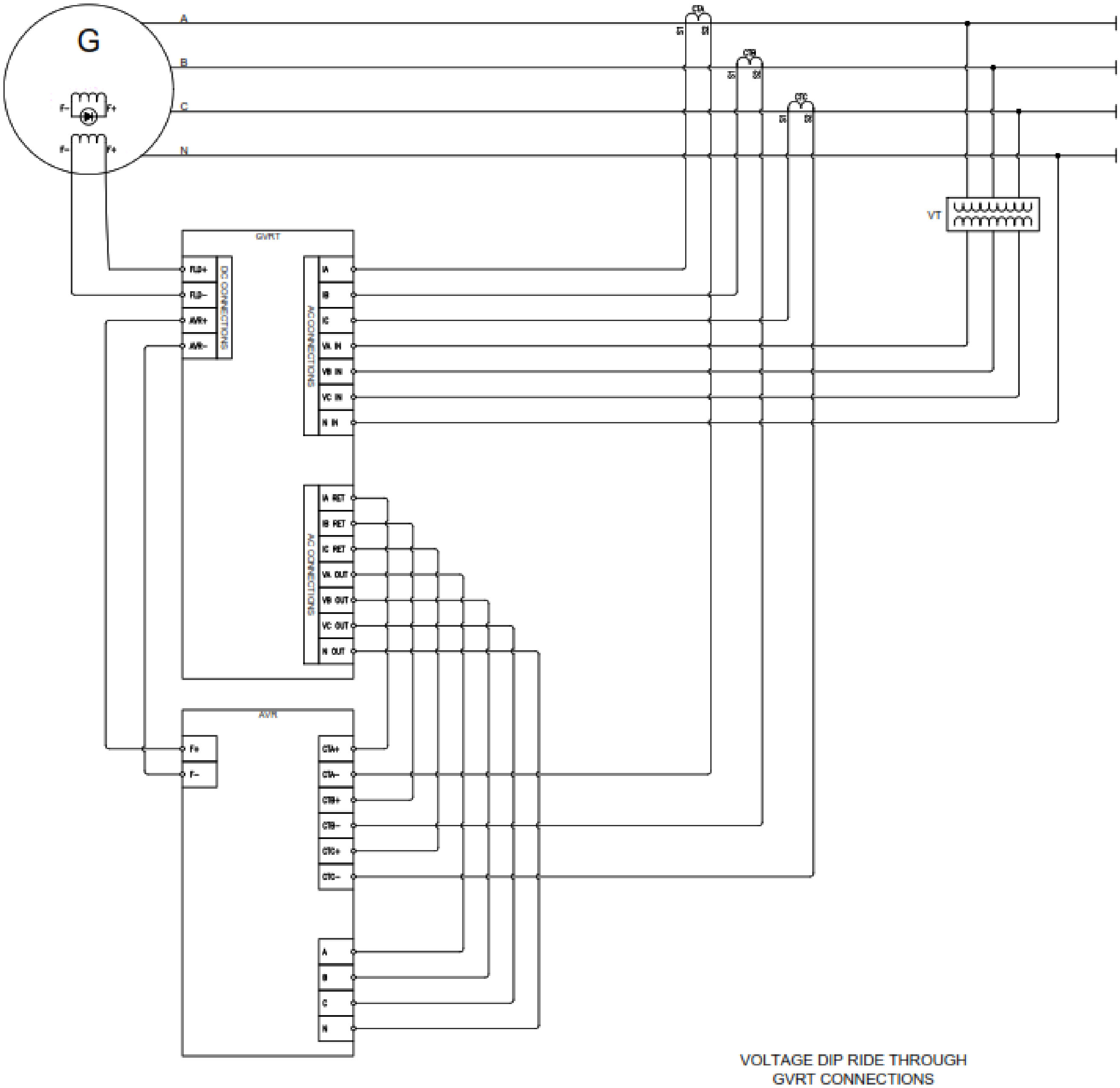

Fig. 31. Example of OneStep Power's GVRT connections to a generator.

11.1.3. Testing Methodology

If the system being tested has inconsistencies in the control and protection systems, there is the potential for incorrect operation and system damage. Equipment that may have such hidden issues include:

- AVRs
- speed controllers
- governors
- load share controllers
- protection relays/protection devices
- power management systems

These devices may present as operating correctly in normal conditions but cause incorrect operation during transients caused by extreme operational conditions or fault scenarios. Potential issues may include:

- incorrect tuning
- incorrect limits
- incorrect settings
- incorrect wiring
- device failures

As this potential for failure does exist, use of the GVRT is staged in a manner that causes these inconsistencies to manifest prior to inducing extreme transients that could lead to damage. This is done by a standardised testing procedure based on the following basic steps:

1. Each generator is tested individually while not connected to the bus. Testing is started at a shorter time period in the range of 150 to 350 milliseconds. This test period is increased in steps of 100 to 300 millisecond intervals depending on system response until the final full test time period as set out in the OTP is reached.

2. Each generator is separately connected to a bus that has no other generators online and has all bus-ties open. The same procedure of starting at a small time period and then increasing that period until the final test time is achieved is undertaken.

3. Two generators are connected to the same bus with all bus-ties open. Test durations are gradually increased to full test duration.

4. This same procedure is then repeated until all generators have been tested with at least one other generator.

5. Multiple generators are connected to buses with bus-ties closed. At this point there should be a good confidence in the system to respond as designed and the testing procedure can start at a higher test period of 400 milliseconds or greater with each progressive step being larger until the final test duration is reached.

If, at any point in this protocol, the system response is outside the acceptable limits, testing is halted, a “requires further investigation” (RFI) is opened and the engine generator set(s) will need to be rectified before testing can continue.

It is not possible to describe the acceptance and RFI criteria in this document as they will be based on the system configuration and design. The OTP will contain the acceptance requirements and the RFI Manual will provide procedures for each system that is tested.

Around the vessel, a loss of non-critical systems may be experienced, however during a successful test no DP-critical systems can be lost.

Appendix B - ZeroDip Operational Description

As the voltage collapse instigated by the GVRT is a slow reduction it is not possible to verify the low voltage ride through capability of a system in the time periods required for an effective test. To induce a voltage collapse that would be sufficient to verify the low voltage ride through capability the industry test of opening and closing a single breaker feeding a bus, commonly referred to as the “bang-bang” test, was taken, expanded upon and automated to work in conjunction with the GVRT. The ZeroDip was the result of this development.

The operational theory of the ZeroDip is to remove all supplies from a section of the network under test and then re-energise the section after a definite time period. The ZeroDip achieves this by opening a breaker that is feeding a section of the network and then closing another breaker after a user-defined period to re-energise that section of the network. Network and bus-tie configuration is the primary factor when selecting the switching order of the circuit breakers.

In the initial steps of testing, where possible, it is preferred that the circuit breaker used to re-apply power to the dead section is fed from multiple generators to prevent overly large power swings on a single generator. When used in conjunction with the GVRT it is possible to generate a single waveform showing both the under-voltage and over-voltage component of a short circuit style fault.

Though avoiding overly large power swings when undertaking ride through testing is preferred, ZeroDip can be used to assist in verification of generator response testing including load rejection and load application. In addition to this, correctly selecting the circuit breakers to operate and the loads at which the switching is occurring can be used to show system responses and resilience against faults such as pole slip.

The ZeroDip was designed to work on the same full duplex communications and control network as the GVRTs and has a similar architecture with two microprocessors on board each unit. The first microcontroller is used for control and time synchronization. The second microcontroller is dedicated to AC measurement and calculation. Two microcontrollers are used so that high overhead AC calculations do not interrupt the synchronization and timing of the tests while still allowing for real time calculation and safety features.

11.1.4. Connection Arrangement

Control of the circuit breakers requires that the ZeroDip is temporarily installed with connections made directly to the opening and closing coils of the selected circuit breakers. A connection to the main bus is also required to capture bus voltage. Figure 32 shows an example of the ZeroDip installed on a three bus system and the connections required.

As the switching speed required to achieve the voltage waveforms needed to verify ride through are not possible with traditional synchronization devices the circuit breakers are not switched through a sync check relay. Switching circuit breakers in this manner carries the inherent risk of closing unsynchronized supplies together resulting in a crash synchronization. To prevent this from occurring there are a number of hardware interlocks and safety procedures that have been implemented with the ZeroDip.

The safety interlocks include a dead bus relay and circuit breaker status feedback. Circuit breaker status is used to prevent the close signal being issued if the first circuit breaker fails to open following an open command. The dead bus interlock is implemented to ensure that if, for any reason, the bus is still live during the test, the second circuit breaker will not receive a close command.

11.1.5. Testing Methodology

The procedural protections in place are:

- racking the circuit breakers into the test position before any connections are made
- verification of correct connections by a second person
- verification of interlocks by testing with the circuit breakers in the test position
- verification of correct operation with the circuit breakers in the test position
- extended test time for 1 second for the first operation once circuit breakers have been racked back into service position

If any of the above steps results in an unexpected outcome an RFI is opened and testing cannot proceed until the RFI has been closed.

Once the ZeroDip installation has been verified as correct with all safety systems operating as designed, the testing procedure as set out in the OTP can be started. The OTP will follow the same procedure as shown here with acceptance and RFI criteria set during the OTP development phase.

The generalized procedure for ZeroDip is as follows:

1. Complete safety and operational checks.

2. Conduct a test with a time period that is somewhere generally between 200 and 400 milliseconds.

3. Increase the testing period in steps of 100 to 300 millisecond steps based on system responses until the final test period is reached.

If at any point an RFI is opened, testing is to be halted until the RFI is resolved.

A loss of non-critical systems may be experienced, however during a successful test no DP-critical systems can be lost.

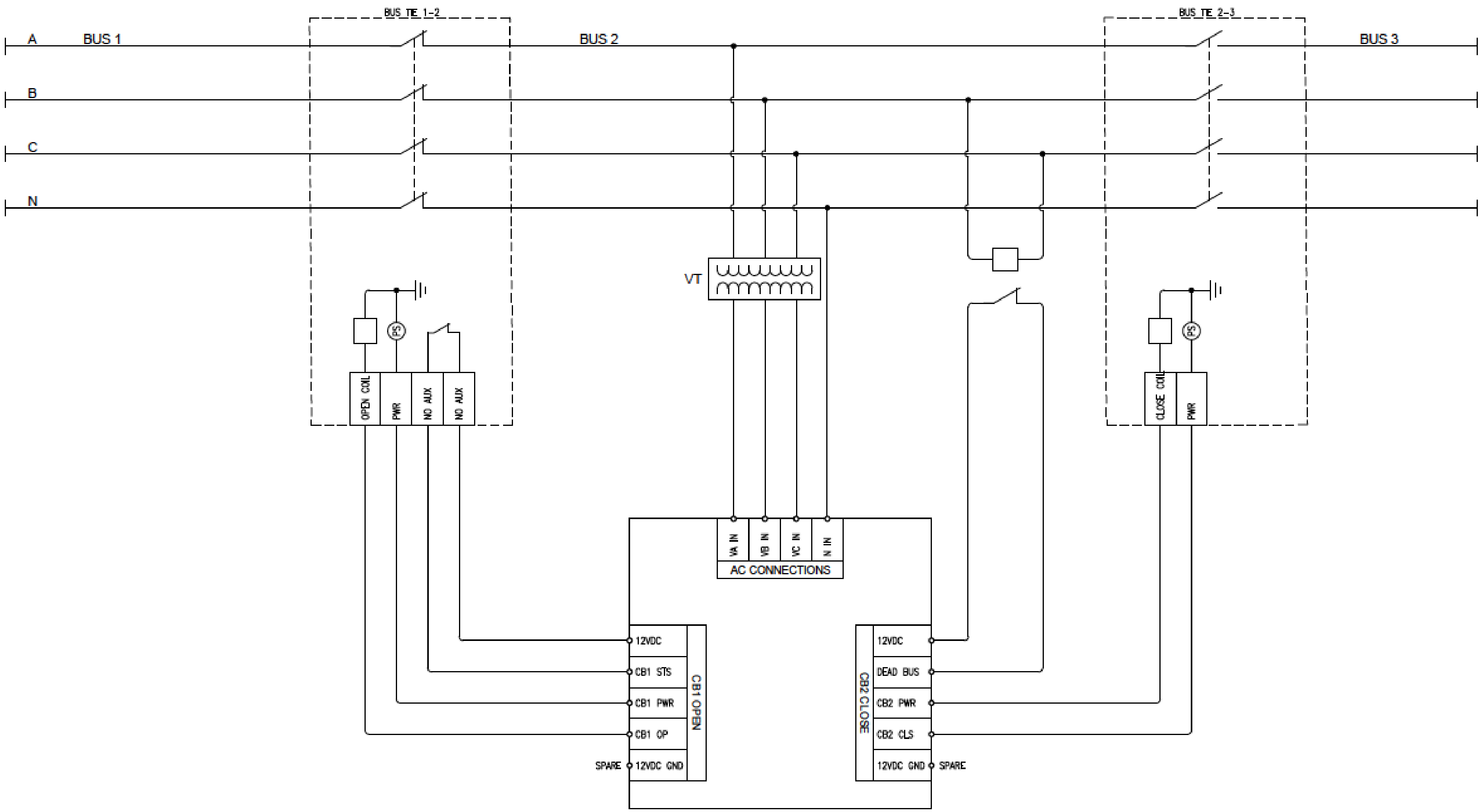

Fig. 32. Example of OneStep Power's ZeroDip connections to a set of bus-ties. Equipment under test is connected to bus 2.

Appendix C - Testing not included in an Equivalent Integrity Protocol

The following test programs are strongly recommended to be performed as part of a ship's acceptance, however they are not part of the demonstration of closed bus equivalent integrity demonstration.

Network testing

Testing for software failures of the protection network is generally not performed in dynamic positioning power system applications. OneStep Power supports the implementation of a suitable network test protocol; however, without a change in the application requirements, the test is not considered necessary for demonstration of equivalent integrity. The failure mode and worst case outcomes are identical in both open and closed bus scenarios.

Testing for the Worst Case Failure

The power management system and associated protection networks may be subject to software-based threats such as cybersecurity intrusions, buffer overflows etc. The worst case failure in these scenarios is loss of the network. Testing to an agreed and published standard should be considered. There are suitable independent third party technologies available on the market for this purpose.

LV cross-connection testing

OCIMF and MTS have both identified low-voltage cross-connections as a concern area for safe and predictable DP operations. While not the focus of a closed bus equivalent integrity study, OneStep Power is proud to present validation solutions for low voltage cross-connections.

Testing for the Worst Case Failure

All low voltage cross-connections, defined as system subsections which have power supplied from two or more redundant groups, should be tested for a range of faults including earth fault and short circuit below the point of cross-connection.