Marlborough Lines Network Standard

DN017 – HV DG Connection and Operation Standard

DOCUMENT ISSUE STATUS

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1 General

1.1 Purpose

This connection and operation standard details the requirements for connecting High Voltage Distributed Generation (HV DG) to the Marlborough Lines (MLL) Network.

MLL is required to comply with a broad range of obligations relating to safety and reliability. Prior to connecting any DG system to the network, MLL must assess the requirements of all relevant regulations and standards, as well as its potential to impact:

- safety of our staff and contractors working on our network
- the quality of supply to all customers on our network
- correct operation of the DG
- the customer's point of connection
- network protection

1.2 Scope

Embedded Generation (EG) is considered as one or more generating units embedded within an installation. The term EG will be used throughout this standard as it is specific to generation at one location. Distributed generation (DG) is considered as the collection of EG distributed throughout MLL's network.

The voltage at the point of connection to MLL's network determines which standard applicants shall follow. This standard covers HV connected DG. Connection requirements for LV connected generators are defined in Marlborough Lines LV DG Connection and Operation Standard.

This standard applies to new (or modifications of any) HV EG, capable of operating in parallel with any part of the Distribution Network. This could include solar, wind, hydro or energy storage systems (batteries) connected via Inverter Energy Systems (IES).

This standard does not cover standby generators isolated from the network nor any other isolated generation. If there is a closed electrical circuit between MLL's network and the output of the generator, then it is defined as operating in parallel to the network irrespective of whether it is exporting power or not.

This document shall be read in conjunction with DN014 DG Connection Policy.

This standard is approved for external release.

1.3 References, Standards and Codes

The following documents are referred to in this standard or provided background material for the development of this standard:

MLL Document	Description
DN005	Network Connection Standard
DN010	Network Earthing Standard
DN014	DG Connection Policy
DN015	DG Congestion Management
DN016	LV EG Connection and Operation Standard
MLL F128	HV DG Connection Initial Application Form
MLL F129	HV DG Connection Final Application Form

External Document	Description
AS/NZS 3000	Electrical installations (known as the Australian/NZ wiring rules)
AS/NZS 3010	Electrical installations - Generating Sets
AS/NZS 4777.1:2016	Grid connection of energy systems via inverters. Part 1: Installation Requirements
AS/NZS 4777.2:2020	Grid connection of energy systems via inverters. Part 2: Inverter Requirements
AS/NZS 5033	Installation and safety requirements for photovoltaic (PV) arrays
AS/NZS 5139	Safety of battery systems for use with power conversion equipment
AS/NZS 61000.3.3	Electromagnetic compatibility (EMC) Part 3.3 Limits - Limitation of voltage changes, voltage fluctuations and flicker in public LV supply systems, for equipment with rated current less than or equal to 16A per phase and not subject to conditional connection.
AS/NZS 61000.3.5	Electromagnetic compatibility (EMC) Part 3.5 Limits - Limitation of voltage fluctuations and flicker in LV supply systems, for equipment with rated current greater than 16A.
AS/NZS 61000.3.7	Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems.
AS/NZS 61000.3.100	Specifies steady state voltage limits in public electricity system at the customer point of connection.
AS/NZS IEC 62116	Utility-interconnected photovoltaic inverters – Test procedure of islanding prevention measures
CEC Inverter List	Australian Clean Energy Council Approved Inverter List. Found here.
Electric Vehicle Charging Safety Guidelines	Worksafe Guidelines for safe electric vehicle charging.

Electricity Safety Regulations (ESR)	NZ Regulations to ensure the health and safety of members of the public and prevent damage to property. Found here.
Electricity Industry Participation Code (EIPC)	The Electricity Authority's Electricity Industry Participation Code 2010 governs how the electricity market operates. (the code). In particular Part 1 or Part 1A of Schedule 6.1.
EEA Guide	EEA Guide for the connection of Small-Scale Inverter Based Distributed Generation 2018

1.4 Definitions and Abbreviations

The following definitions are referred to in this information pack:

Definition	Explanation
Anti-islanding Protection	A protection system to detect islanded conditions and disconnect the inverter(s) from the Distribution Network.
Certificate of Compliance (COC)	Registered electrical workers must audit their own work and fill out a certificate of compliance as proof that they have complied with electrical safety standards and codes. A customer should request the COC from their electrical contractor when work is completed. MLL will need to see the COC before connecting the electrical installation to the MLL network.
Distributed generation (DG)	Generation installed at a customer's installation that is capable of exporting electricity back into the local network. When viewed from MLL's perspective the generation is distributed throughout our network.
Energy Storage System (or ESS)	A system comprising one or more batteries (or alternative technology) that store electricity generated by Distributed Energy Resources or directly from the grid, and that can discharge the electricity to loads.
Embedded Generating System (or EG)	One or more generating units embedded behind an installation control point (ICP).
(ICP) Installation control point	A point of connection on a local network or an embedded network which the distributor nominates as the point at which a retailer will be deemed to supply electricity to a customer.
Installation	A complete electrical installation from the point of a service main connection to the network, to the most remote circuit supplied by the switchboard.
Inverter Energy System (or IES)	A system comprising one or more inverters together with one or more energy sources (which may include an ESS) and controls, where the inverter(s) satisfies the requirements of AS/NZS 4777.2.
Maximum aggregate system capacity	Is the sum of all inverter nameplate ratings behind the PoC.

Point of Connection (PoC)	A point at which electricity may flow into or out of our network.
Point of Supply	The point at which electricity equipment that exclusively supplies a property crosses that property boundary.
Single Wire Earth Return (or SWER)	Parts of the electrical high voltage Distribution Network that use a single live conductor with the earth as the return current path. All premises are supplied at LV either as single-phase or split-phase electric power.
Total System Capacity	The aggregate nameplate rating (kVA) of all individual EG systems behind the PoC.

The following abbreviations are referred to in this information pack:

Abbreviation or Acronym	Definition
CEC	Clean Energy Council
CoC	Certificate of Compliance
DER	Distributed Energy Resources
DRM	Demand Response Mode
DG	Distributed Generation
EG	Embedded Generation
ESS	Energy Storage System
GID	Grid Isolation Device
GPR	Grid Protection Relay
HV	High Voltage (> 1kV)
IES	Inverter Energy System
L-N	Line to Neutral Voltage
LSDG	Large Scale Distributed Generation (> 10kW)
LV	Low voltage (≤ 1kV)
NVD	Neutral Voltage Displacement
PV	Photovoltaic
ROI	Record of Inspection
SSDG	Small Scale Distributed Generation (≤ 10kW)
SWER	Single Wire Earth Return
THD	Total Harmonic Distortion

2 Technical Requirements

2.1 Labelling and Signage

All EG Systems shall comply with AS/NZS 3000.

Labels and signs on IES, including cables, shall meet the requirements of AS/NZS 4777.1, AS/NZS 5033 and AS/NZS 5139.

Examples of signage and labelling required for IES installations are provided in AS/NZS 4777.1, Appendix A. Marking requirements for inverters are detailed in AS/NZS 4777.2, Clause 7.

2.2 Maximum System Capacity and Export Limits

The maximum network capacity shall be verified by MLL at the time of assessment. The standard HV connections to MLL's network are at 11kV or 33kV. Dedicated infrastructure such as feeders or zone substations may be required depending on the proposed capacity and location.

Where there are multiple EG systems at a premise connected to a single point of connection, the system capacity will consider the aggregate of the existing and proposed EG systems. For IES, MW ratings shall be taken at unity power factor (e.g. MW = MVA nameplate rating).

It should be recognized that there can be significant variation in network characteristics, plant thermal ratings, customer loads depending on location and connection at different voltage levels, and as such an accurate assignment of injection capacity cannot be made without undertaking the appropriate network studies or calculations.

Limiting export does not necessarily permit the installation of a larger system to offset onsite load. The disconnection of an IES system can cause site load to rapidly transfer over to the network. This can cause step changes in voltage on both the network and the customer's point of connection, which can affect other customers' quality of supply. As the size of such voltage fluctuations increases with the capacity of the IES system, it is essential to assess the potential impacts on the shared network based on the full capacity of the proposed system, rather than on export limits.

2.2.1 Standard Connection - Export Limits at Point of Connection

Most connections will be considered standard. The exceptions are covered in section 2.2.2

The Export limit shall be assessed and determined during application review. It will be based on:

1. Penetration of EG Systems on the Distribution System;
2. The network connection voltage;
3. Asset capacity limits on the Distribution System;
4. Power quality checks on the Distribution System;
5. Voltage regulation impacts on the Distribution System; and
6. Distribution System protection impacts.

Technical studies required such as export capability are covered in section 3.

2.2.2 Non-standard Connection - Export Limits at Point of Connection

The following networks are considered non-standard when connecting EG connections to them.

SWER Networks. These are designed to be low capacity, long radial distribution lines and have technical constraints which limit the capacity of EG connections supplied by SWER.

Isolated Networks. These are networks not connected to the main grid and are instead supplied by dedicated remote area power stations (RAPS).

No HV EG may be connected to either of these network types.

2.3 Generation Control

2.3.1 Export limits at Point of Connection

IES shall have a soft limit export control function available. It may be integrated into the inverter or an external device.

Where the net export limit is exceeded, the export control function shall operate to ensure the IES meets the export conditions within 15 seconds. For configurations where an inverter provides the power limitation capability, the total cumulative export of all the inverters shall not exceed the approved export limit.

The ability of the customers IES to Export at the limits described above are not guaranteed and will depend on the characteristics of the Distribution Network, which may change over time. For example, inverter power output may change where power quality response modes are in operation.

2.3.2 Phase Balance

All HV EG connections shall be three-phase. The IES must have a balanced input and output.

2.4 Inverter Energy Systems

2.4.1 General

The following requirements apply to IES EG units:

1. The inverters shall be tested and certified by an authorised testing laboratory as being compliant with AS/NZS IEC 62116 for active Anti-islanding Protection.
2. Installed in compliance with AS/NZS 4777.1. For IES > 200kVA this standard can be used as a guide.
3. Shall comprise of inverters with the following power quality response modes available:
    a) Voltage Response Modes (Volt-Var and Volt-Watt)
    b) Reactive power control mode
    c) Central control mode
    d) Fixed power factor
    e) Frequency-Watt mode
4. IES EG units generating at LV should comprise of inverters that are:

a) Tested by an authorised testing laboratory and be certified as being compliant with AS/NZS 4777.2:2020 (or later) with an accreditation number.
b) Registered with CEC as approved grid connect inverters.

Specific requirements are detailed in section 2.10.1 of this Standard.

2.4.2 Energy Storage System (ESS)

The connection of an ESS (such as batteries) capable of supplying electricity to an electrical installation or the Distribution Network is considered Grid Connected, unless the inverter is connected behind a break-before-make switch.

Where the ESS is considered to be Grid Connected:

1. the ESS shall be subject to the requirements of this Standard including the same general requirements outlined in section 2.4.1;
2. the installation of the ESS shall comply with AS/NZS 5139;
3. ESS are either externally DC coupled to an AC inverter or packaged as a product into an integrated system with an AC inverter. The following requirements shall apply to ESS inverters:
   a. the inverter capacity for any ESS inverter will be included in the total system capacity;
   b. the Export limit for the ESS inverter will be considered as part of the Export limit at the point of connection.

The installation and commissioning of ESS shall be certified as compliant by a registered electrical worker.

When an energy storage system has the ability to charge from the network, the proposed system may be subject to limits on the time and/or rate at which it may charge, and a constraint may also be applied on the amount and/or rate of energy discharged back into the network.

2.5 Network Connection and Isolation

An EG System shall only connect to the MLL Network via one point of connection.

The customer shall provide a means of isolation that is capable of disconnecting the entire HV EG System from the MLL network. The requirements for this device are detailed in Table 1.

Table 1 Connection Isolation Device Type

Generating Capacity	Connection Voltage	GID Type
<= 1.5 MVA	11 kV	Load Break[1]
> 1.5 MVA	11 kV	Circuit Breaker
Any	33 kV	Circuit Breaker

Note 1: CB may be required as a result of the technical studies.

The GID should be installed as close as possible to the point of connection to MLL's network and shall be owned by MLL. This isolation device is for the use of personnel working on the distribution network as means of isolation of the EG system when required. It shall be located in an accessible place to approved MLL contractors at all times.

Where a circuit breaker GID is required it shall be either an HV pole mount recloser or HV ground mount switchgear. It shall have associated protection, control and communications equipment.

The GID protection settings shall be considered as the primary protection for the distribution network, they are not considered a backup protection device for the EG System. The protection will be set to grade with our equipment in the upstream HV network.

Depending on the network connection location and voltage, the EG system may need to select appropriate generator, step-up transformer, and grounding options to mitigate potential fault level issues.

Step up transformers shall have an earthed interwinding shield between the primary and secondary windings for high frequency harmonics attenuation.

2.5.1 Subtransmission Connections

HV EG connected to MLL's network at 33kV is required to connect to a network bus, typically an existing MLL zone substation.

Where it is not practical to connect to an existing network bus a new network bus can be created by installing a new 33kV switching site. Which shall consist of:

- One or more circuit breakers depending on the configuration and operational requirements of MLL.
- Full compliance with MLL's protection standard.
- Diverse communications equipment.
- Duplicate DC supply to the protection relays, communications equipment and circuit breaker.
- CT's and VT's with secondary winding available for protection and metering purposes.

2.6 Earthing

The earthing requirements shall be in accordance with the requirements contained within the relevant Standards. These standards include, but are not limited to:

- DN010 – Network Earthing Standard
- For IES, AS/NZS 4777.1
- For ESS, AS/NZS 5139
- For PV systems, AS/NZS 5033
- For Generating Sets, AS/NZS 3010
- For all the above, AS/NZS 3000

2.6.1 HV Neutral Connection

HV EG directly connected to the Distribution System shall have their neutral effectively isolated from earth. This is to limit any contribution to a Distribution System earth fault, and to inhibit the flow of harmonic currents through the neutral.

2.7 Protection

The protection scheme shall be designed in accordance with the applicable regulations and this standard which require a protection system that detects all credible fault types.

Protection design at the point of connection shall be capable of achieving reliable discrimination of faults within the generating system installation and those on the network.

Fault levels shall not exceed the equipment rating of the EG System, Distribution Network equipment, associated switchgear, and protection equipment. Where the EG System can contribute to fault levels, MLL shall:

- Conduct fault studies which includes the fault contribution from the EG System; and
- Provide the Customer with the existing fault levels and protection equipment ratings to assess whether the design of the EG System exceeds relevant equipment ratings.

Where it is determined the design of the EG System has the potential to raise the fault levels on the Distribution Network beyond the capacity of the MLL's equipment, the Customer shall meet the cost to upgrade the equipment, and ensure that their switchboard and equipment can withstand the total prospective fault currents.

If required, the customer must provide adequate protection and metering CT cores for protection systems and VT reference signals as required and specified by MLL.

2.7.1 Inverter Integrated Protection

Inverter integrated protection shall be compliant with the principles of AS/NZS 4777.1 and AS/NZS 4777.2 (Section 4).

2.7.1.1 Passive Anti-islanding

Passive Anti-islanding settings shall be set to the values given in Table 2 below.

Table 2 Integrated Protection - Mandatory Passive Anti-islanding Settings

Protection function	Settings (% of nominal voltage)	Trip Delay	Maximum disconnection time
Undervoltage 2 (V < <)	30%	1 s	2 s
Undervoltage 1 (V <)	78%	10 s	11 s
Overvoltage 1 (V >)	113%*	1 s	2 s
Overvoltage 2 (V > >)	115%*	-	0.2 s
Underfrequency (F <)	45 Hz	1 s	2 s
Overfrequency (F >)	52 Hz*	-	0.2 s
Minimum reconnection time	60 seconds		

*differs from AS/NZS 4777.2: 2020 Table 4.1 and 4.2

Inverters must not connect or reconnect to the network unless the voltage and frequency of the network has been steady for at least 60 seconds.

2.7.1.2 Active Anti-islanding

Active Anti-islanding requirements shall apply as per AS/NZS 4777.2, clause 4.3.

2.7.2 Fault ride through

Specific requirements for an EG system to ride through network faults will depend on the location and capacity of the EG system.

This will be explored during the technical studies outlined in Section 3. Depending on the outcome of these studies, EG systems may be required to ensure fault ride through capability in accordance with Schedule 8.25A of the Code and or the System Operator's conditions.

2.7.3 Central Protection

Central protection provides cover for the entire EG installation. It is very important to preserve safety of grid personnel and the general public. It is additional to inverter integrated protection in section 2.7.1.

Table 3 Central Protection Requirements

Central Protection Requirements (ANSI)	IES > 30kVA	Non IES (Rotating machines)
Passive anti-islanding protection (27P, 59P, 81U, 81O, 81R)	Yes	Yes
Overcurrent and Earth fault (51P, 50N)	Yes	Yes
Directional Power (32)	Yes[1]	Yes[1]
Synchronisation (25)	No	Yes
Neutral Voltage Displacement (59N)	No[2]	Yes

Note 1: Directional Power may be required on some EG systems, refer 2.7.3.3.
Note 2: NVD may be required based on the size of the EG system.

Where the EG System comprises multiple inverters, all inverters on all three phases of the EG System shall simultaneously disconnect from the Distribution Network in response to the operation of protection or automatic controls.

The Grid Protection Relay (GPR) shall be connected as close to the point of connection as practicable and provide the central protection function.

The GPR shall be integrated in a fail-safe manner. i.e. the EG system should disconnect whilst the GPR is out of service.

2.7.3.1 Passive Anti-islanding Protection

Passive anti-islanding protection shall be provided by the GPR. This may be in addition to the inverter integrated settings (section 2.7.1.1) where this can be considered as backup protection.

The following two tables outline required settings for IES and Rotating Machine central protection relays installed at the point of connection.

Table 4 Central Protection - IES Passive Anti-islanding Settings

Protection function	ANSI Code	Settings (% of nominal voltage)	Trip Delay
Undervoltage 2 (V < <)	27P	30%	1.0 s
Undervoltage 1 (V <)	27P	78%	10 s
Overvoltage 1 (V >)	59P	115%	1.0 s
Overvoltage 2 (V > >)	59P	120%	0.2 s
Underfrequency (F <)	81U	45 Hz	2.0 s
Overfrequency (F >)	81O	52 Hz	2.0 s
Rate of change of frequency (ROCOF)	81R	± 4 Hz/s	0.25 s

Table 5 Central Protection - Rotating Machine Passive Anti-islanding Settings

Protection function	ANSI Code	Settings (% of nominal voltage)	Trip Delay
Undervoltage	27P	78%	10 s
Overvoltage	59P	110%	1.0 s
Underfrequency	81U	45 Hz	2.0 s
Overfrequency	81O	52 Hz	2.0 s
Rate of change of frequency (ROCOF)	81R	± 4 Hz/s	0.25 s

2.7.3.2 Overcurrent and earth fault protection

This protection must coordinate/discriminate with all relevant protection, including the distribution network protection and any other customers' protection.

2.7.3.3 Directional Power (Export Limit)

Directional power protection is required when an export limit has been set for the point of connection and the IES does not employ "soft" controls as described in 2.3.1. It may be used as a backup in addition to a central export monitoring device.

All generating systems with a maximum export limit may be required to include directional power protection to detect and prevent the inadvertent exceeding of the agreed export limit to the network.

2.7.3.4 Synchronisation

The generating system must ensure it is synchronised with the network before connection to the network. If one or more phases of the network are lost, then the generating system must disconnect from the network.

To prevent non-synchronised connections, auto-synchronising and synchronisation check closing protection shall be installed across all CB's that could be closed out of synchronisation.

2.7.3.5 Neutral Voltage Displacement (NVD)

NVD protection is required to ensure that an EG System disconnects if there is a high voltage network earth fault.

2.7.3.6 Fail safe protection

All protection systems installed as part of the EG system shall remain operational following a loss of mains supply from the network (e.g. have backed up DC supplies of suitable capacity) and be of fail-safe design.

The generating system is to automatically disconnect from the network in the event of the failure of any supplies or loss of communications to the protection equipment that would inhibit the correct operation of the protection equipment.

2.7.4 Network Protection

Where EG is required to be connected to the network via either a dedicated feeder or zone substation, MLL will require the dedicated assets to be protected by our own protection systems which will be provided by MLL at the customer's expense.

For GID circuit breakers (detailed in section 2.5) the network protection shall have the following elements; Overcurrent, Earth Fault, Under/Over Voltage, Neutral Volt Displacement and any others deemed necessary by MLL.

2.7.5 Feeder Automatic Re-closing

MLL apply an automatic feeder re-closing scheme on the majority of our Distribution Network. Automatic re-closing of the feeder involves open and closing (after a predefined "dead time") the upstream circuit breaker in an attempt to clear temporary faults. This may happen up to three times and be as quick as 1.0 seconds depending on the location. It may be appropriate to set a faster undervoltage element on rotating machines to ensure they isolate before the reclose is attempted. Please discuss these requirements with MLL.

The EG System shall disconnect within the dead time to ensure safe restoration and avoid damage to the EG system.

Non-IES EG shall not reconnect to the network after the restoration of the grid supply without verification that normal conditions have been restored and permission is received from MLL.

The IES reconnection procedure is detailed in AS/NZS 4777.2, section 4.7.

2.8 Operating Voltage and Frequency

Available voltage for connection is dependent on the location and EG System capacity. MLL operate 11kV and 33kV distribution networks. We may require new assets to have a higher rated voltage than they operate at to meet our future objectives.

HV EG systems shall be designed and installed to maintain compliance with the following:

1. AS/NZS 4777.2 for IES EG units.
2. AS/NZS 61000.3.7 and AS/NZS 61000.3.100 for non-IES EG.

2.8.1 Automatic disconnection

In accordance with AS/NZS 4777.2, Clause 4.5.2, the inverter shall operate the automatic disconnection device within 3 seconds when the average voltage for a 10-minute period exceeds $V_{nom\text{-}max}$, where $V_{nom\text{-}max}$ in NZ is 108%.

2.8.2 Frequency range

The EG shall be capable of supplying rated power for frequencies between 45 Hz and 52 Hz.

IES shall maintain continuous operation for frequency variations within the limits specified in AS/NZS 4777.2:2020, Table 4.4 under the New Zealand row. The IES shall respond to frequency changes as defined in Table 6.

Table 6 Frequency-Watt Response Modes

Inverter Response	Frequency where power output level is max	Frequency where power output level is min
Decrease in Frequency	45 Hz*	45 Hz*
Increase in Frequency	50.25 Hz*	52 Hz

*differs from AS/NZS 4777.2: 2020 Table 4.5

Figure 1 provides a graphical representation of the Frequency-Watt response.

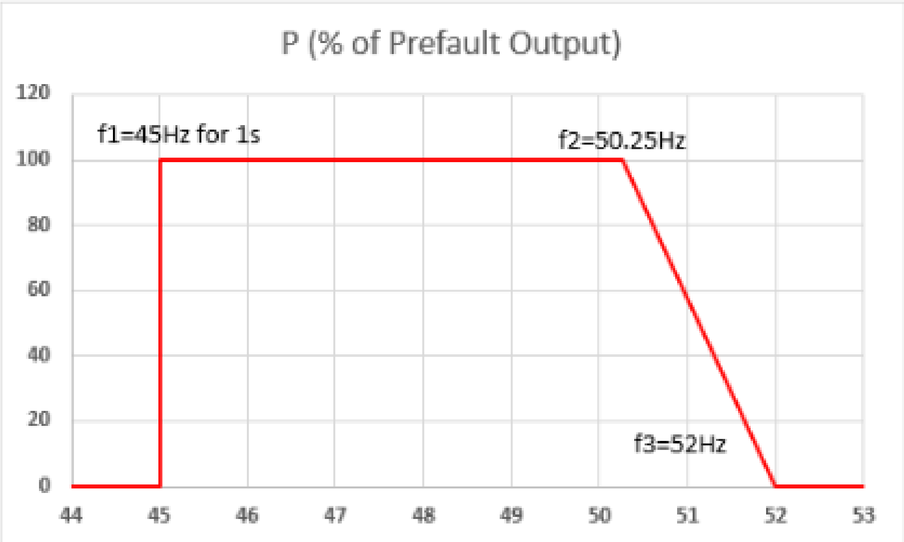


Figure 1 Function for Freq-Watt response mode

2.9 Metering

An import/export meter is a requirement for all grid connected inverter installations and must be certified and comply with the requirements of part 10 of the Code. Metering installation is to be arranged by the Customer with their Electricity Retailer.

Refer to section 2.12 for power quality metering requirements.

2.10 Power Quality

The generating system must not impact on the quality of supply to MLL's distribution network or other customers. It is the responsibility of the owner of the EG system to ensure ongoing compliance with their assigned power quality obligations and undertake appropriate tests as required. All power quality measurements and limits are referenced to the point of connection.

The operation of an EG system must not result in a material increase in the number of transformers tap changer operations in the adjoining network.

2.10.1 Power Quality Response Modes

All HV EG systems shall have power quality response modes enabled. These may be enabled through integrated capabilities (e.g. IES) or a central controller. MLL may need to change control modes and/or settings from time to time to suit changing network requirements.

2.10.1.1 For IES

Technical studies will determine the optimal power quality response mode the EG shall operate under. The volt-watt response mode is mandatory and shall operate concurrently with other power quality response mode(s) as required. Setpoints for Volt-Var and Volt-Watt shall be configured as per Table 7 and Table 8 below.

The power quality response modes respond to changes in voltage at the PoC. The intent of applying these modes is to allow EG to be connected to the grid while avoiding any adverse effect on the voltage at the point of connection.

The Volt-VAr response mode varies the reactive power absorbed or supplied by the inverter in response to the voltage at its AC terminals. It is further described in section 3.3.2.3 of AS/NZS4777.2:2020.

Table 7 Volt-Var response mode settings

Reference	Voltage (% of nominal voltage)	Reactive Power % of Rated IES Output
V_{V1}	90%	60% supplying
V_{V2}	96%	0%
V_{V3}	103%	0%
V_{V4}	106%	60% absorbing

The Volt-Watt response mode varies the maximum active power output level of the inverter in response to the voltage at its PoC. It is further described in section 3.3.2.2 of AS/NZS4777.2:2020.

Table 8 Volt-Watt response mode settings

Reference	Voltage (% of nominal voltage)	Max Active Power
V_{W1}	105%	100%
V_{W2}	109%	20%

Settings must be programmed into each inverter and protected from unauthorised changes.

2.10.1.2 For Non-IES (e.g. rotating machines)

The specific power quality response mode will be determined based on the outcome of the technical study, and will be either:

1. Voltage control mode
2. Volt-Var control mode
3. Fixed power factor mode.

For fixed power factor control mode, the customer must maintain the agreed power factor at the point of connection.

2.10.2 Voltage Fluctuation and Flicker

The customer must ensure that voltage disturbances caused by the generating system, the overall electrical installation or by any appliances, do not result in voltage disturbances to other network users, greater than the limits prescribed in AS/NZS 61000 (part 3.3 or 3.5), at the point of connection.

The IES shall comply with AS/NZS 4777.2, Clause 2.8 with respect to voltage fluctuation and flicker, Clause 2.9 with respect to transient voltage limits, and to Clause 2.10 with respect to DC current injection.

2.10.3 Ramp Rate

To ensure that there is no adverse impact on network voltage, the maximum allowable rate at which EG can be loaded and unloaded shall not exceed;

1. For IES EG, 16.67% of rated power per minute, as per AS/NZS 4777.2.
2. For Non-IES EG, a maximum of 1000kW per minute.

In addition, when carrying a controlled shut down of any EG, the load on the generating system should be reduced to a minimum before opening any of the generating unit's circuit breakers.

2.10.4 Harmonics

MLL's requirements around harmonics are detailed in section 6.4 of DN005 – Network Connection Standard available on our website.

Harmonic currents produced by IES shall comply with the requirements of AS/NZS 4777.2, clause 2.7. Except the total harmonic current distortion (I_{THD}) which has a reduced allowance. It shall not exceed 3%.

MLL may require a network harmonic study to be performed to confirm they meet our requirements.

2.10.5 Power Factor

IES operation at a power factor other than unity is acceptable as the inverter operates with power quality response modes enabled. However, the inverter shall be capable of absorbing or supplying at least the specified reactive power required by the Volt-Var response mode, in section 2.10.1, down to a power factor of 0.8 for all active power output or input levels.

Refer AS/NZS 4777.2 section 2.6 for further detail.

Non-IES (i.e. rotating machines) shall be designed and operated to adequately control real and reactive power output to achieve a power factor at the point of connection of greater than 0.9 lagging or leading.

2.11 Communication Systems & SCADA

Remote monitoring and control will be required where EG represents a significant portion of the total area load (typically export of 1MVA or more), a network constraint has been identified or where deemed necessary by MLL. Typical information MLL may require:

- Voltage, Amps, Frequency, Power Factor, kW, kVA and kVAR
- Customers circuit breaker status
- Voltage control mode, setpoints etc
- EG specific information, i.e. number of generators in service, battery state of charge etc

MLL may require the ability to curtail EG system export remotely, and to vary voltage or var control setpoints remotely, to manage voltage, power system constraints, demand response, or at the System Operator's request. If specified, the EG system shall include a mechanism to receive setpoints from MLL and respond accordingly.

If the protection and control requirements call for it an independent optical fibre cable with diverse route to the supplying HV circuit should be installed between the EG system and the nearest MLL fibre connection point. The fibre cable will be specified and owned by MLL.

2.12 Power Quality Meter

A power quality meter shall be installed on all HV EG systems. It shall be installed as close to the point of connection as practical. The meter will be specified and owned by MLL but paid for by the customer. It shall monitor the following metrics:

- Voltage, Amps, Frequency, Power Factor, kW, kVA and kVAR
- Total Harmonic distortion and harmonics (1^{st} to 50^{th}).
- Flicker
- Voltage and current unbalance
- Disturbance event recording

If required, the customer must provide access to metering CT cores and VT reference signals for our meter. We typically require a class S rated CT's, but this will be confirmed by MLL.

3 Technical Studies

Technical studies are required to be conducted at the customer's expense to enable connection to the distribution network. These studies shall be undertaken by an MLL approved Electrical Engineering Consultancy having specialist network modelling, protection and generation experience and is accredited to undertake designs for MLL or Transpower.

Before conducting any technical studies, the scope shall be reviewed and approved by MLL.

The completed technical studies will be reviewed by MLL to confirm settings and suitability against this standard.

Typical network studies shall include;

1. System capacity assessment (Section 3.1)
2. Power quality (Section 3.2)
3. Protection requirements (Section 3.3)

A digital power system model shall be provided to MLL for the EG system. Any data/models provided to MLL must be compatible with the DIgSILENT PowerFactory version 2021.

3.1 System capacity assessment

The following items shall be considered as part of this study:

- SLD showing integration with MLL's network and upstream protection devices.
- Power transfer stability limits (PV & PQ analysis) with and without VAR control.
- Contingency Studies, i.e. worst-case network configurations during network outages.
- Identification of other generating systems which may impact the connection.
- Voltage regulation at the connection points and at connecting zone substation buses; under no and full generation, under seasonal load variations, under rapid solar variation – and their combinations to seek out the expected and worst-case conditions.
  i.e. calculation of the expected impact on the annual tap changer tap count.
- Identification of required voltage control mode and proposal of acceptable setpoints and droop settings.
- Potential impact upon Grid Exit Point reactive power exchange.
- Plant energisation studies.
- Requirements for curtailment.
- Generation and/or load rejection studies.

3.2 Power quality

The following items shall be considered as part of this study:

- Power quality allocation for fluctuation and distortion.
- Voltage variations at the POCs for trips at full generation.
- Dynamic stability of EG to voltage disturbances and under earth faults to show a damped response and managed transient over voltage, during selected network fault scenarios.

- Voltage variation and its effect on MLL's zone transformer tap changers, line regulators or the Blenheim Grid Exit Point.
- Identification of required power quality monitoring and SCADA connection.
- Details of performance standards.
- Harmonic penetration modelling to assess the induced harmonic voltages at each even and odd harmonic up to the 50th harmonic within the 33kV network and their comparison to the required maximum levels at the Blenheim GXP.
- Flicker analysis

3.3 Protection requirements

The following items shall be considered as part of this study:

- Fault current contribution, if applicable. Maximum fault levels at the points of connection at network full load and full generation with all circuits in service will be provided by the studies for MLL to review against network equipment capabilities.
- Protection study considering fault currents and protection times under different network configurations.
- Identification of protection systems that will be required to meet MLL standards.

4 Inspection, Testing and Commissioning

EG installations require an electrical inspection by a registered Electrical Inspector as defined as high risk prescribed electrical work in the Electricity (Safety) Regulations.

On-site testing and commissioning shall be undertaken in accordance with AS/NZS 4777.1, AS/NZS 3000, AS/NZS 5033 (where applicable), the equipment manufacturer's specifications, other relevant standards and this technical standard.

4.1 Commissioning Plan Requirements

For HV EG systems installers must submit a commissioning plan to MLL a minimum of 30 business days prior to the commencement of commissioning.

The commissioning plan shall be broken into three parts:

A. Off-line, pre-connection testing. Customer testing to ensure the EG system is ready for connection to the network. Section 4.1.1
B. Compliance testing. Customer testing to demonstrate the EG system complies with MLL's technical requirements. Section 4.1.2
C. On-line, post-connecting testing. Customer testing to demonstrate the EG system performs as agreed. Section 4.1.3

It shall confirm, at a minimum, the following points:

- What elements of the EG are proposed to be tested;
- The specific steps that the customer proposes to test the above elements;

- The pass/fail criteria for each test, including any settings/values that are to be verified and performance standards that will be assessed;
- The proposed dates for testing and commissioning of each part.

MLL may elect to attend any of these testing stages to witness the testing and compliance with our requirements.

4.1.1 Off-line (pre-connection) testing

Off-line (pre-connection) testing and commissioning is required to prove that the equipment that has been installed is operating correctly under test conditions. The commissioning report must confirm that all protection and control systems are functional, and their settings are consistent with information approved by MLL.

The following commissioning results must be submitted to MLL five business days prior to the date arranged for the compliance testing. Documents showing compliance with all relevant Standards, including:

- Copy of Certificate of Compliance (COC);
- For IES, a copy of commissioning records in line with AS/NZS 5033;
- Any other applicable testing records, e.g. earthing system tests;
- Protection test results, signed off by a competent protection technician;
- Written confirmation of the anti-islanding protection device tested and compliant with this standard.
- Power quality response modes enabled and their settings.
- Site Single Line Diagram, signed off as as-built.

MLL will not attend site to complete the next phase of commissioning until the above required documentation has been submitted.

4.1.2 Compliance testing

Prior to connection of the EG system to the network, MLL may inspect and where necessary, require the customer to test certain parts of the system, while onsite to confirm compliance.

The testing shall be undertaken by suitably competent parties, with prior approval of MLL in accordance with the approved commissioning plan. MLL is not responsible for directing, leading, or performing any of the required tests.

The extent of compliance testing will vary depending on the generation capacity and connection configuration. It shall include a combination of injection testing and controlled testing which covers the following:

- Interlocking
- Under/Over Voltage
- Under/Over Frequency
- ROCOF
- Synchronisation (where applicable)

- Directional Power
- Protection systems (Over current, earth fault etc)

These are provided as a guide and not an extensive list of all the required tests. Any deficiencies detected during the compliance tests must be resolved before making the final network connection.

4.1.3 On-line (post-connection) testing

On-line (post-connection) commissioning is required to confirm that the EG system performs as expected and is consistent with the approved design.

MLL will attend the on-line commissioning at its discretion. The testing shall be undertaken by suitably competent parties, with prior approval of MLL in accordance with the approved commissioning plan. MLL is not responsible for directing, leading, or performing any of the required tests.

The extent of on-line testing will vary depending on the generation capacity and connection configuration. It shall include testing which covers the following:

- Ramp rate
- Export limits
- SCADA indication and control (where applicable)
- Synchronisation (where applicable)
- Power quality control modes

These are provided as a guide and not an extensive list of all the required tests. Any deficiencies detected during the on-line tests will require the EG system to be disconnected and must be resolved before reconnecting to our network.

4.2 Commissioning Results

The customer must compile the results in a commissioning report and submit this report to MLL within 20 business days of undertaking the tests. The commissioning report shall outline the tests completed and compare each value with that expected during design.

The report shall conclude that all protection and control systems are functional, and their settings are consistent with information provided to and approved by MLL.

It shall also include the final approved and as-built drawings, installed settings, DIgSILENT PowerFactory network model, test results and specifications.

5 Operations & Maintenance

The owner or operator or the EG system is responsible for the following.

a) Maintenance and safe operation of the EG system (including protection devices, cabling and generation components).

b) Ensure the generation system complies with all relevant acts, regulations, standards (including this one) rules and codes of practice.
c) Ensure appropriate signs/labels and safety warnings are visible.
d) Ensure that any changes to the electrical installation at the supply address are performed by an electrician lawfully permitted to do the work and that the customer holds a Certificate of Compliance issued in respect of any of the changes.
e) Seek approval prior to altering the EG system in terms of upgrades, extensions, expansion, augmentation or any other kind of alteration, including operational, control, or protection settings of the EG System. MLL will advise if additional work is required and the associated cost (if any).
f) Operating the system within the generation export limit imposed by MLL (if applicable).
g) The customer shall notify MLL of any system or communications outages or failures.

An operation and maintenance plan shall be produced by the customer and a copy to remain on site. This plan shall be made available to the MLL on request.

Upon, or at any time after, completion of the installation of the EG system, Marlborough Lines may request access to the premises to conduct an inspection of the system. This is to verify compliance with this standard and may include checking of:

- Certificate of Compliance (COC)
- Electrical Safety Certificate
- Inspection and Record of Inspection (ROI)
- Generation capacity
- Operation of the grid protection device (anti-islanding)
- Power response modes enabled and set correctly (e.g. Volt-VAr and Volt-Watt)

Marlborough Lines may, from time to time, isolate any EG in order to perform certain maintenance tasks or manage the network capacity in accordance with our operational requirements or DN015 Distributed Generation Congestion Management.

6 Records and Information

MLL is responsible for ensuring that it has plans and records of EG installations to ensure the safe and reliable operation of our network. MLL may keep records pertaining to an EG installation within its documentation systems for the lifetime of the installation.

6.1 Initial Application Form

The application form is required for MLL to evaluate EG connecting to our network. It will provide information such as:

- Customer contact details
- Installation site details
- EG type(s)
- EG capacity
- Battery ESS capacity (where applicable)
- Engineering consultancy completing the studies.
- Connection voltages and grid connection equipment specifications.
- IES specifics and compliance with AS/NZS 4777.2 standards.
  (e.g. datasheets, certificates, PQ curves, ratings, fault current contributions etc)
- Site diagram (refer Appendix A – Site Diagram Example)
- Site Single Line Diagram (refer Appendix B – System SLD Examples)

6.2 Final Application Form

The Final Application form captures the finalised design and control settings that will meet our standards. It will also include answers to any requirements we provided in our response to the Initial Application.

MLL may conclude that a final application is not required. In this case approval to connect will be clearly provided in our response to your initial application. Otherwise the applicant will need to complete a final application form too.

6.3 As-built information

IES documentation must be stored on site in accordance with AS/NZS 4777.1, Section 7, and available to MLL on request. Non-IES EG shall also store relevant operation and maintenance information onsite.

Upon, or at any time after, completion of the installation of the EG system, Marlborough Lines may request access to the premises to conduct an inspection of the system. This is to verify compliance with this standard and may include checking of:

- Certificate of Compliance (COC)
- Electrical Safety Certificate
- Inspection and Record of Inspection (ROI)
- Generation capacity and phase balance

- Operation of the grid protection device (anti-islanding)
- Power response modes enabled and set correctly

6.3.1 Commissioning results

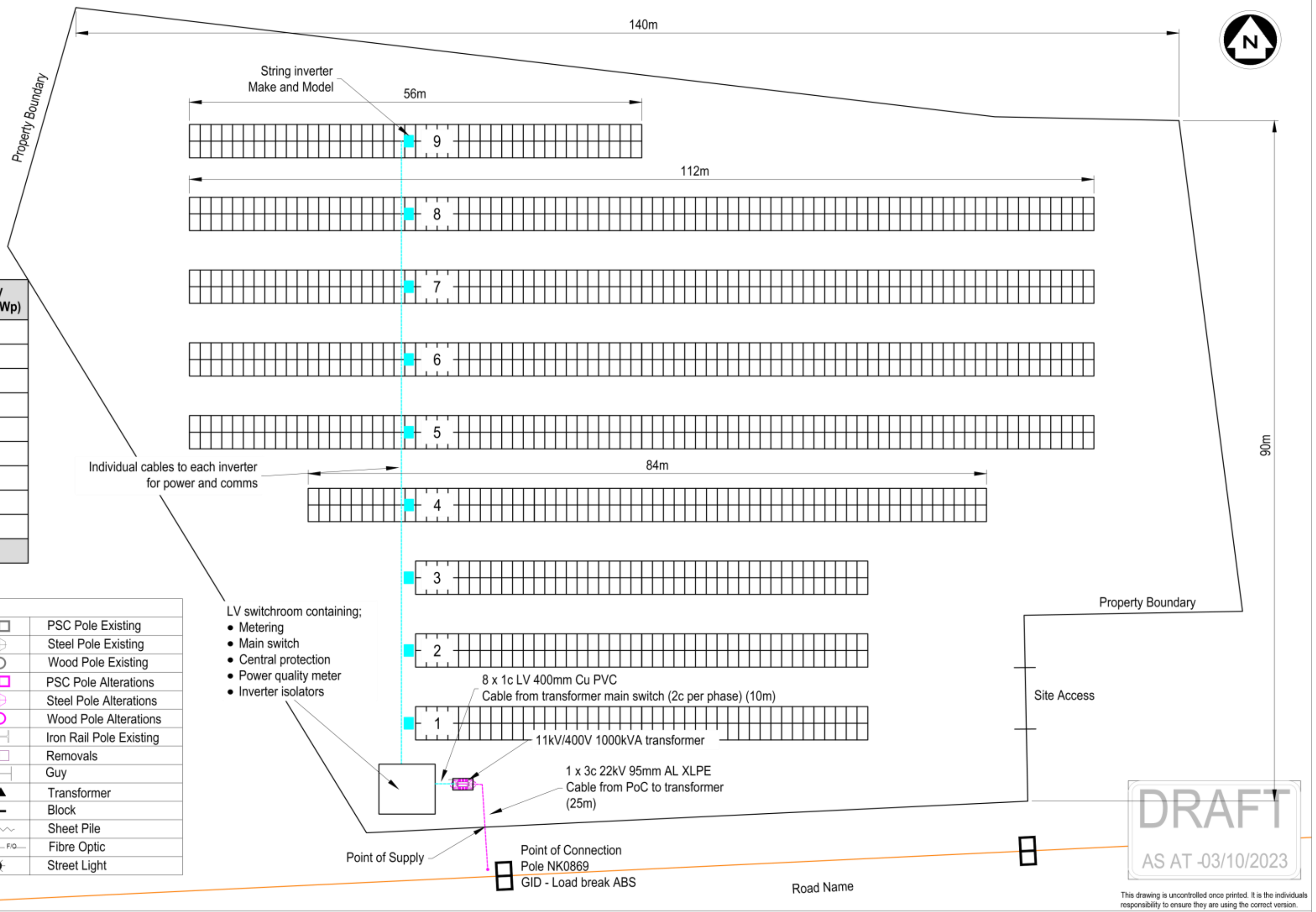
Our requirements for this are detailed in Section 4.2.

Appendix A – Site Diagram Example

Please provide a sketch (or aerial photo) of the property with the following items identified:

- Point of Connection (PoC)
- Mains cable type, route, and length.
- Meter box, main switchboard, distribution boards, sub cables.
- Inverter(s), inverter(s) isolator, PV array and central protection device location.
- EG unit locations and energy source.

An example is provided on the next page



Inverter Number	Inverter Size (kVA)	Energy Source (kWp)
1	100	100
2	100	100
3	100	100
4	100	170
5	100	200
6	100	200
7	100	200
8	100	200
9	100	100
9	**900**	**1370**

LEGEND

	33kV Line Existing		PSC Pole Existing
	33kV U/G Cable Existing		Steel Pole Existing
	33kV Alterations		Wood Pole Existing
	11kV Line Existing		PSC Pole Alterations
	11kV U/G Cable Existing		Steel Pole Alterations
	11kV Alterations		Wood Pole Alterations
	LV Line Existing		Iron Rail Pole Existing
	LV U/G Cable Existing		Removals
	LV Alterations		Guy
	S.F.B.		Transformer
	Oil Switch Ring Main Unit		Block
	SF6 Ring Main Unit		Sheet Pile
	SF6 Control Unit	FO FO	Fibre Optic
	Fibre Pit		Street Light

Revision History

Revision	Drawn	Design	Checked	Approved	Date	Amendments
A	BJS	BJS			03/10/2023	Layout proposal

Project: **Random PV Site**

Title: Project Overview

Marlborough Lines Ltd.
1-3 Alfred Street
Blenheim, New Zealand
Tel: 03 577 7007

Designed:	BJS
Drawn:	BJS
Checked:	
Approved:	
Status:	Draft
Date:	03/10/2023
Sheet:	1 of 1
Scale:	1:50
A3 Drawing No.	PV1234
Rev	A

Appendix B – System SLD Examples

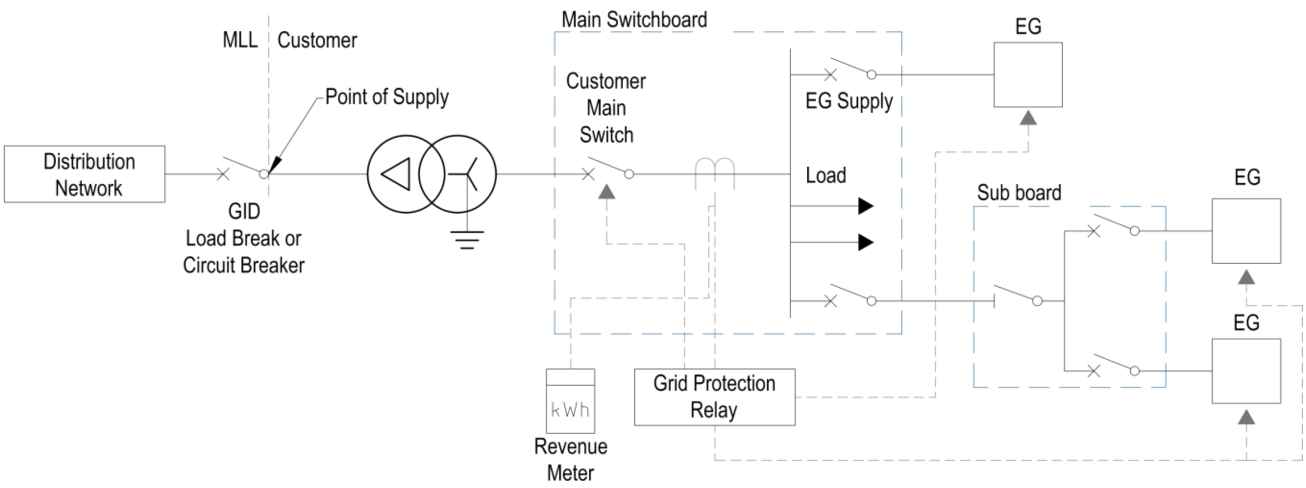
A single line diagram (SLD) needs to contain information on the installation wiring from the point of connection off the Marlborough Lines network, through to all the EG on site, including where the customer's load is connected.

It shall contain information on all protection devices and switches, as well as any communications required to achieve the desired operation of the system (i.e. export limit, central protection etc.).

SLDs must use correct symbols (referenced from AS/NZS 3000:2018) and shall contain at least the following information:

- Point of Connection (PoC)
- Revenue Meter
- Main switch/CB
- Main switchboard and any distribution boards
- Load(s)
- Generating Units i.e. Inverter(s)
- Equipment ratings
- Maximum output rating
- EG isolators and/or protective devices
- Energy Source, i.e. PV array, battery, Wind, Hydro
- Communication paths i.e. export limit, central protection
- Monitoring equipment i.e. current transformers
- MLL SCADA connection
- Grid Isolation Device location

<u>Example 1 – Single Step up transformer</u>



Example 2 – Embedded HV Switchgear