Black Start from Non-Traditional Generation Technologies

Network Innovation Allowance
June 2019

Power Island Strength and Stability in support of Black Start

In partnership with:

tnei

nationalgridESO

Contents

Executive summary

TNEI Services Ltd (TNEI) was commissioned by National Grid ESO to investigate the capability of non-traditional technologies in the restoration of the GB power system in the event of a partial or total system shutdown. The project is a Network Innovation Allowance (NIA) project initiated by National Grid ESO, with support from SP Energy Networks. The overall aim of the NIA project was to provide insight into the capability of several prevalent non-traditional technologies: wind, solar, storage, demand side response (DSR) and electric vehicles (EV), to provide ancillary services to National Grid ESO in the event that the GB network requires a Black Start.

Responding to the significant changes in the energy landscape in the past decade, National Grid ESO are seeking to understand how renewable generation and distributed energy resources (DER) could facilitate the restoration of the GB power system with the decline and decommissioning of traditional Black Start providers (larger, synchronous power stations). The creation of smaller, distributed power islands is of particular interest as a result, whereby these would be initiated on distribution networks and grow to energise the transmission network. This project has considered the technical capability of the technologies, the challenges of creating and maintaining small power islands with high penetrations of renewables and DER, and how to better predict the reliability and availability of renewable generation in such a scenario.

The project has three distinct deliverables.

- **Report 1:** Overview of the capability of non-traditional technologies to provide Black Start and restoration services;
- **Report 2:** Investigation of the challenges around power system strength and stability specifically in relation to power islands with high penetrations of renewables and converter-based technology; and
- **Report 3:** A sophisticated planning tool specifically designed to simulate distributions for the reliable output of wind over periods of hours to days, and how these distributions vary on timescales of months and years.

This report is Report 2, one of the three deliverables from the “Black Start from Non-Traditional Technologies” project.

Power islands, also known as non-isolated microgrids, can improve the supply security and reliability of parts of the distribution network. The upfront planning and design of microgrids need to consider not only the main components (such as microgrid controller, distributed energy resources (DERs), controllable load, and a communication system), electrical boundaries and Point of Connection (POC), but also a range of technical requirements which include DER and storage, voltage and frequency response, mode transfer and stability, protection systems and settings, power quality, earthing, control and communications. These and other requirements are addressed in IEC 62898-1:2017.

National Grid ESO’s Black Start System Operability Framework (SOF) envisages the application of non-isolated microgrids for Black Start restoration services by means of a number of progression steps. Growing a microgrid or power island to energise larger parts of the distribution network could be achieved through the clustering of different microgrids, provided robust communication and control systems are in place to co-ordinate the interaction between the different microgrids.

Due to their size microgrids have different electrical characteristics compared to the larger power grid. Furthermore, they tend to have a much higher share of renewable and converter connected resources. This results in distinct technical characteristics which directly impact the strength and stability of microgrids, namely:

- high variability of load and generation;
- low system inertia;
- low short circuit level;
- greater voltage-frequency coupling; and
- a loss of earth reference.

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These technical attributes result in a number of operational challenges including voltage and frequency stability, converter stability, protection reliability, fault ride through capability and electrical safety.

This report summarises the learnings from a number of research papers and case studies to show how the above-mentioned operational challenges could be addressed using a number of different techniques to ensure the stable and reliable operation of microgrids. Solutions include:

- increasing system inertia using synchronous compensators, exchanging kinetic energy from wind farms, or using the synthetic inertia capability of energy storage systems.
- adaptive tuning of the convertor responses based on the mode of microgrid operation.
- adding energy storage systems, wind-turbine de-loading and/or demand response for low frequency support.
- changes to protection relay settings to ensure faults can be correctly detected in low short circuit level scenarios.
- installation of dedicated earthing.

The report examines the practical application of some of these solutions through two microgrid case studies – one located in the Azores and the other in the Caribbean. Both MV microgrids have a peak load of just over 2MW and contain traditional synchronous generators, high shares of renewable energy resources and energy storage systems.

The learning points from these case studies include:

- 100% inverter-based grids can be operated at megawatt-scale
- grid forming or voltage-control-mode inverters, used in conjunction with battery energy storage systems (BESS) can be used successfully to establish and maintain the voltage and frequency on a microgrid without the support of synchronous machines
- system frequency stability can be improved by introducing energy storage systems which can provide a fast frequency response to arrest frequency drops and oscillations during network disturbances
- inverters can provide sufficiently high current during faults to trigger the protection devices on the MV system
- microgrid controllers can dynamically control all the generation and demand in a microgrid system.

The report concludes that the operational challenges traditionally associated with MV microgrids can be successfully mitigated through the application of modern-day microgrid controllers, energy storage systems, and the adaptive adjustment and finetuning of convertors and protection systems. This suggests that microgrids/power islands can be operated reliably, and have sufficient strength and stability to play an important role in supporting Black Start of the distribution and transmission power grid.

1 Introduction

The "Black Start from Distributed Sources" System Operability Framework (SOF) [1] proposes two possible methods of Black Starting the power grid using DER technologies. The first method proposes the use of large embedded generation, typically connected on the 132kV distribution network, that is able to self-start and re-energise the transmission network. The second involves the establishment and operation of small self-contained distribution-level microgrids or power islands at medium voltage (MV) levels.

In the context of this report a microgrid and power island is understood to describe the same concept, namely a part of the MV distribution network that is electrically disconnected from the larger grid and operated in an islanded mode during a partial or total power system shutdown. The microgrid has self-forming capability or Black Start capability and is able to synchronise to the rest of the distribution network once the grid has been restored.

This report focuses on the establishment and operation of distribution level microgrids and investigates the technical and operational challenges associated with running power islands or microgrids with a large share of DER.

Firstly, an overview is provided of microgrids looking at typical components, topology, technical requirements, roles and responsibilities, and possible Black Start progression scenarios. This is followed by an assessment of typical operating characteristics of microgrids, the operational challenges it presents, and possible mitigation strategies. Two microgrid case studies are reviewed to illustrate how some of the challenges have been addressed in commercial projects. Lastly the learning points are summarised, drawing out findings and conclusions of particular interest to both NIA project and the "Distributed ReStart" Network Innovation Competition (NIC) project which aims to test and demonstrate the use of distributed power islands in a Black Start.

2 Microgrids – A technical overview

2.1 Microgrid definition and application

The IEC 62898-1:2017 guidelines for microgrid project planning and specification [2] defines a microgrid as a "group of interconnected loads and distributed energy resources with defined electrical boundaries that acts as single controllable entity and is able to operate in both grid-connected and island mode".

A power island is defined as "part of an electric power system, that is disconnected from the remainder of the interconnected system, but remains energised". Microgrids can exist at any voltage level between LV and HV, but the "Distributed ReStart" NIC project will focus only on microgrids operated at MV (11kV–66kV) or HV ($\geq$ 132kV) level.

The IEC specification distinguishes between isolated and non-isolated microgrids. Isolated microgrids are microgrids that are isolated from a larger power system, for example the grids found on oceanic islands. Non-isolated microgrids are connected to the main power distribution system through a Point of Connection (POC), or Point of Common Coupling (PCC) and can operate in a grid-connected or islanded mode. Disconnection from the grid can either be the result of automatic protection operation for supply reliability reasons, or as a result of deliberate action, for example for maintenance work to be performed.

Microgrids can have many different applications which include:

- improving supply reliability and securing supply for all or part of their loads which could include the distribution network, campuses, facilities such hospitals, military bases etc.
- providing off-grid power supply in very remote areas e.g. rural electrification or oceanic islands.
- reducing energy costs for microgrid users in grid-connected mode by utilising energy storage, dispatchable generation and loads, and providing ancillary services to the grid.
- disaster-preparedness where microgrids may be built in natural disaster-prone areas.

In the context of Black Start and distributed restoration the main focus is on non-isolated microgrids that aim to improve supply reliability and security of supply in the event of a partial or total system shutdown.

2 Microgrids – A technical overview

2.2 Microgrid components and topology

The IEC 62898-1:2017 guidelines for microgrid project planning and specification [2] defines a microgrid as a "group of interconnected loads and distributed energy resources with defined electrical boundaries that acts as single controllable entity and is able to operate in both grid-connected and island mode".

The typical components of a microgrid include:

- microgrid controller(s);
- generation forecasting system including a weather prediction system;
- load forecasting system;
- communication system;
- energy storage systems e.g. Battery Energy Storage System (BESS);
- dispatchable generation, typically synchronous generators such as diesel/gas/biomass generators;
- non-dispatchable generation, mostly asynchronous in nature. This includes:
    - asynchronous induction wind generators (e.g. Type 1 – fixed speed induction generator or Type 2 – variable rotor resistance induction generator);
    - asynchronous converter connected generators (e.g. Type 3 – doubly-fed asynchronous wind generator, or Type 4 full converter wind generator); and
    - converter controlled Solar farms;
- point of connection (POC), typically a breaker or switch (in the case of non-isolated microgrids only); and
- controllable load. Load can be controlled via switching at substation level, or by means of Demand Side Response (DSR) where the load is isolated at the customer end.

An overview of the main components of a non-isolated microgrid is shown in figure 2.1.

Although microgrids tend to have the same components, the number and connection of these components result in different topologies. IEC 62898-1 [2] identifies 3 common microgrid topologies used in non-isolated microgrids and one for isolated grids. The topology most likely to be found on MV distribution networks and used in Black Start scenarios is presented in figure 2.2. As a general rule the complexity of the control and communication system increases with the diversity, number and geographic dispersion of DERs in the microgrid.

Figure 2.1
High level overview of the components of a non-isolated microgrid [16]

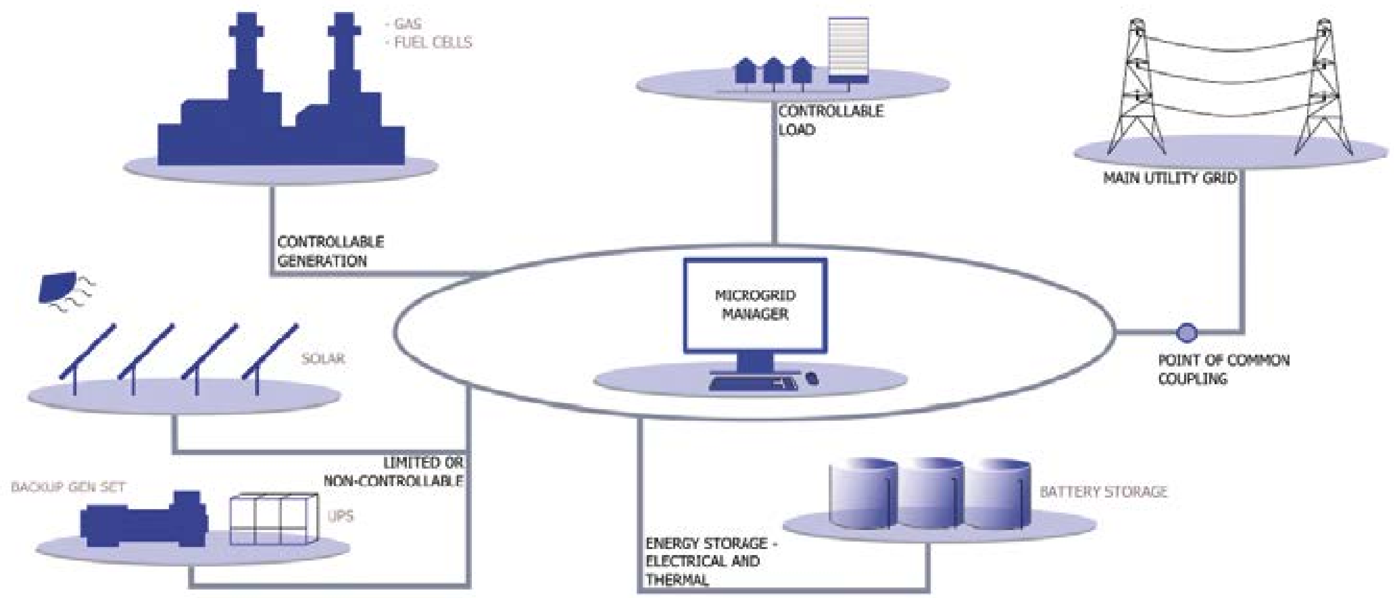

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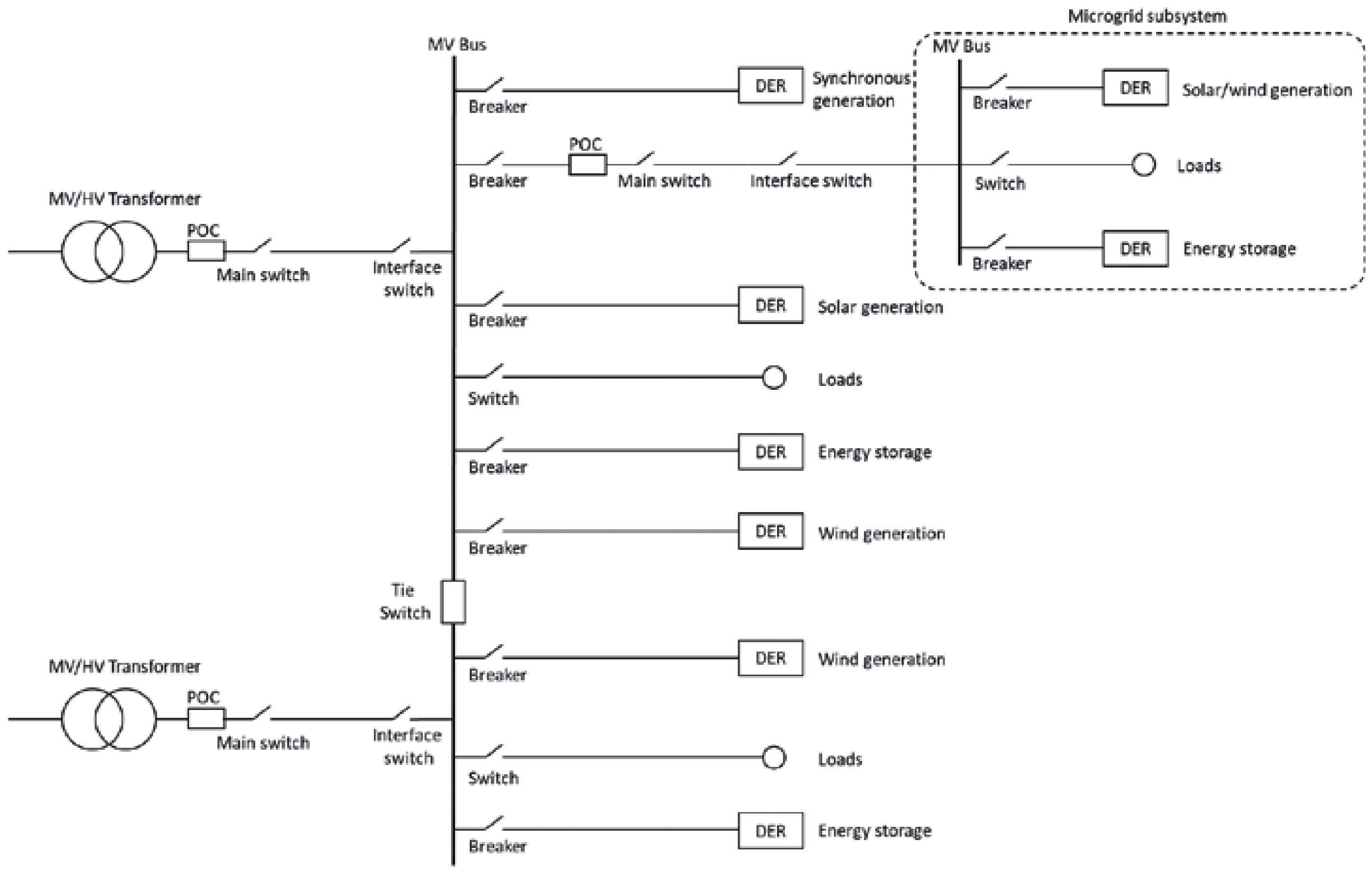
Figure 2.2
Example of a multi-bus and multi-level microgrid topology [2]



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2 Microgrids – A technical overview

2.3 High-level technical requirements

An overview of the high-level technical requirements for microgrids is provided for context with the operational issues discussed in later sections.

2.3.1 DER and Energy Storage requirements

DER generators in microgrids can be either synchronous generators or converter based. Synchronous generators are usually directly coupled to the gird, have rotating inertia and usually work in droop mode to provide primary frequency response. Converter-based DERs are usually configured to control the injection of active and reactive power, the control of voltage and frequency and droop mode (P–f, Q–V).

When the microgrid is in grid-connected mode, the DER shall comply with the same requirements as required for connection of the grid. These requirements are specified in Engineering Recommendations G98 (previously G83) [33], G99 (previously G59) [34], the Distribution Code, the Grid Code [32] and the Connection and Use of System Code. This means that the DER must be able to withstand certain voltage and frequency deviations depending on the size of the generator. Voltage in the microgrid is controlled by both the utility grid and the DER.

Energy storage systems will usually adopt the P/Q control mode and will ensure that power output of the microgrid to the rest of the grid is smooth.

In island mode, the requirements and role of the DER generators and storage systems changes as described in the following sections.

2.3.2 Voltage response requirements

In island mode the DER generators in the microgrid become fully responsible for the control of active and reactive power, and need to respond accordingly when the voltage exceeds the defined operating parameters.

Energy storage systems need to support the DER generators with voltage regulation if the DER generators cannot inject/absorb sufficient reactive power.

2.3.3 Frequency response requirements

Microgrids in island mode shall be able to perform load tracking, and the DER generators should be large enough to ensure that the predetermined critical load can be supplied. At least one or more of the DER generators should be able to provide the frequency reference for the microgrid.

Frequency regulation can be achieved through DER generator active power adjustment through frequency droop control, reduction of load through DSR, or demand disconnection. The energy storage system shall operate in generate mode if the DER generators can no longer supply the load, and in load mode if the DER generating capacity exceeds the load.

The storage system with the largest capacity should be set to control active power / frequency to establish and maintain the frequency in case the other DER generators are not available. The energy storage system will also be responsible for Black Start of the microgrid in the event that the microgrid shuts down when in island mode.

2.3.4 Microgrid mode transfer and stability requirements

The transfer of a non-isolated microgrid from grid-connected to island mode can be either intentional or unintentional, as in the case of a partial or total system shutdown.

If enough DER generation is operating at the moment of disconnection to support the load and maintain acceptable voltage continuity, considering the option of fast demand disconnection to adapt the load to the islanded generation capacity if necessary, the microgrid will island successfully. Otherwise, the microgrid will stop operation and will require a Black Start sequence to restart.

To maintain stability in island mode the microgrid shall have enough DER devices to provide voltage support through self-regulation of reactive power. The DERs operating in Q mode shall be used for voltage support. To maintain frequency stability the microgrid shall provide self-regulation of active power by using DERs operating in P mode to provide frequency support.

Synchronisation control is required for the transition from island mode back to grid-connected mode. The microgrid controller shall monitor the voltage, frequency and phase angle of the distribution network, and when the frequency and voltage are normal again, the microgrid will close the POC breaker and reconnect to the distribution grid.

2.3.5 Protection requirements

Interface protection shall be provided at the POC breaker or switch, and shall be sufficiently sized to withstand the largest possible short circuit current at the POC, either when the microgrid is in island mode, or when it is connected to the wider distribution network.

Typically, the fault current will be smaller in island mode compared to grid-connected mode due to the absence of large synchronous generation and low contribution from converter based DERs. The protection schemes and settings of equipment in the microgrid may need to be changed and adjusted to accommodate the lower fault current levels and greater frequency and voltage fluctuations that occur during system disturbances. Ideally the protection relays should have the capability to automatically switch between two operating modes with different relay settings to operate at different fault levels, although this is generally not a standard feature of MV protection schemes.

The protection scheme for the microgrid POC to distribution system should be coordinated with the existing protection in the distribution network to ensure that it does not interfere with the safe and reliable operation of the distribution system. If the microgrid is connected to the distribution system via a dedicated line, then bilateral power protection should be used to cater for bi-directional flows. A T-connected microgrid should be equipped with directional current protection, and a microgrid directly connected to a LV bus should be equipped with over-current protection [2].

Transformers and rotating generators should have reliable detection and trip immediately upon detecting short-circuit, single-phase to ground or stator phase failures.

DER units should be equipped with under-voltage and over-voltage protection. Provision for under-frequency and under-voltage protection should also be made to implement demand disconnection when the generation can no longer sustain the load.

2.3.4 Power Quality requirements

The microgrid shall have power monitoring capability at the POC. The power quality levels at the DER plant terminals shall be the same in grid-connected and island mode. The microgrid shall not cause unacceptable disturbances to users of the distribution grid, and shall not cause voltage fluctuations or unacceptable flicker during a parallel connection to the grid.

2.3.5 Earthing requirements

The earthing arrangement for the isolated microgrid is important for the reliable and safe operation of the microgrid, and needs to comply with the relevant engineering standards and IEC TS 62257-5. The earthing of DER, transformers and other electrical equipment in the microgrid needs to be compatible with the earthing system of the distribution network. Safe operation should be ensured in grid-connected, island mode and during transfer mode.

In MV microgrids the earthing system should comply with IEC 61936 and in LV microgrids the earthing system should abide by the requirements of IEC 60364.

2.3.6 Control and communication requirements

The microgrid control system is responsible for coordinating and controlling the power balance, demand side response and economic dispatch of resources in the microgrid. It is also responsible for a smooth transfer between grid-connected and island mode without impacting on the distribution network.

The control architecture of a microgrid control system can be either centralised, decentralised or hierarchical. In a microgrid with decentralised control each DER controller relies on local voltage and frequency measurements to self-regulate. In a centralised system a central controller takes all the decisions based on information received from the DER units and measurement points. Based on the measurement data received, the central controller can control one of the DERs as a master generator responsible for determining the voltage and frequency in the microgrid.

2 Microgrids – A technical overview

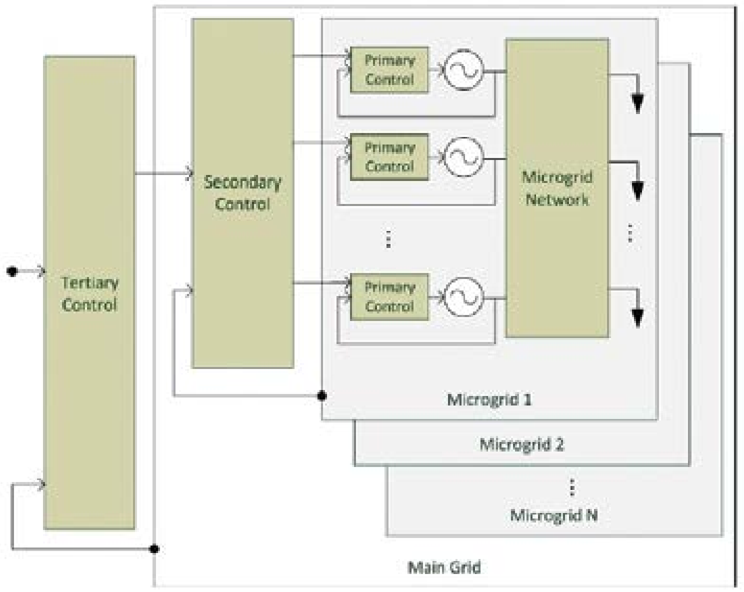
A centralised control system requires reliable communication between the central controller and the rest of the units. This is not always feasible due to the geographic dispersion of the DER units in the microgrid. At the same time a decentralised approach may not be possible due to the strong coupling in operations of the various units in the system which requires a level of coordination which cannot be achieved using only local measurements.

A compromise between a fully decentralised and fully centralised control system can be achieved by means of a hierarchical control scheme consisting of three control levels: primary, secondary, and tertiary as shown in figure 2.3 [5].

- **Primary control** – is the local, or internal control at the DER and is usually the fastest. It is based only on local measurement and requires no communication. Applications include islanding detection, output control, and power sharing and balance control.
- **Secondary control** – is performed by the microgrid Energy Management System (EMS), or microgrid controller, and is responsible for dispatching generation and load to ensure grid stability. It also restores permanent frequency or voltage deviations produced by the primary control.
- **Tertiary control** – coordinates the operation of multiple microgrids interacting with one another and sets optimal set points. Response time is in the order of minutes. This control level is often regarded as part of the distribution grid control system, and not part of the microgrid itself.

Figure 2.3

Hierarchical control levels found in microgrid systems [5]



The three control levels differ in their speed of response and the time frame in which they operate, and infrastructure requirements (e.g. communication requirements) [5]. IEC 62264 is an enterprise-control system integration standard originally designed for an application in the manufacturing industry. However, it is also being promoted for the hierarchical control of microgrids [7].

Besides the requirement for effective and robust communications between the different microgrid components, reliable data communication between the microgrid controller and the distribution system operator (DSO) is also essential. The following information needs to be exchanged with the system operator [2] to enable the system operator to monitor and manage the microgrid as part of the process to restore the distribution network during the Black Start process:

- the status of the POC breaker/switch;
- voltage, frequency and current measurements at the POC;
- active and reactive power at the POC; and
- the state of charge of any energy storage systems.

2.4 Planning and design of microgrids

Non-isolated microgrids have to be planned and designed upfront. The planning and design are beyond the scope of this report, but it is relevant to point out that consideration should be given for the following before implementation and operation of the microgrid. In other words, these are pre-determined rather than operational adjustments.

1. A defined isolation point, called the Point of Connection (POC), which is typically a circuit breaker with/without synchronisation capability.
2. Pre-determined number and size of local embedded synchronous generation contracted by means of a Connection Agreement. The contracted generation would normally have self-starting and grid-forming capability and have a high degree of dispatchability e.g. hydro, waste-to-energy plants, gas or diesel generators.
3. Number and size of non-dispatchable converter-based DER generators such as solar and wind.
4. Number and size of dispatchable converter-based energy storage systems.
5. Demarcation of the power island in terms of the buses and feeders included, based on matching the expected generation and load.
6. Configuration of protection systems to continue operating reliability when the microgrid is in island mode.
7. Active energy management system or control system e.g. microgrid controller(s) to monitor the power island as well as the grid, and ensure optimal voltage and frequency stability of the microgrid.
8. Communication system to enable communication between the DNO, DSO/TSO, embedded generation and equipment in the power island.
9. Systems studies and simulations to verify the stability of the island under different load and generation conditions.
10. Seamless transfer between grid-connected and islanded modes, and synchronisation with the grid during reconnection.
11. Self/Black Starting the microgrid if required after unsuccessful islanding.

2.5 Microgrid demarcation

The boundaries and POC of the power island with the rest of the grid is pre-defined during the planning stage of the power island. The geographical and electrical boundary of the power islands is based on the connection and quantum of expected generation and load and is verified through power system simulations.

The island demarcations should be reviewed from time to time to ensure that the island sizing and boundaries take account of any changes in generation and load over time.

Various controlled islanding methodologies are evaluated in [18]. One of the strategies involves splitting the power network into microgrids across the weak areas of the network, for example the transmission lines where the lowest power is normally exchanged, in order to create strong connected islands. The power islands are created with at least one Black Start unit in each island and sufficient generation capacity to match the load in each island to enable parallel power system restoration. Parallel power system restoration (PPSR) is already used by National Grid ESO [19] and involves sectionalising a power system into several sub-systems and restoring these sub-systems simultaneously in order to speed up the system restoration process.

Each created power island needs to meet the following criteria:

- each island must have its own Black Start capability;
- each island should have the capability to match its generation and load within prescribed frequency limits;
- each island shall have adequate voltage controls to maintain a suitable voltage profile;
- each island shall have the ability to create and maintain a frequency reference;
- all tie points must be capable of synchronisation with the adjacent power islands; and
- all islands should be able to exchange information with the other islands.

2.6 Islanding use case

IEC TS 62898-2: 2018 [4] defines a use case for operating a non-isolated microgrid in island mode after unintentional islanding as would happen in a partial or total shutdown scenario.

The unplanned outage on the main grid would be detected by the microgrid controller, which would then immediately take control over the operating modes of the different DER generators, storage systems, controllable loads and other flexible resources, and switch them to island mode while simultaneously disconnecting from the grid at the POC.

After the microgrid controller has taken control it would inform the DSO about the microgrid's islanding state. If islanding was successful, it would determine the estimated duration of the island mode based on the renewable energy resource forecast, level of diesel or gas, and state of charge of the batteries. It would monitor and regularly update the DSO about the remaining duration. If, due to a lack of production, consumption or flexibility, the island can no longer be sustained, the microgrid controller would safely power off the microgrid and await reconnection to the main grid when possible.

2 Microgrids – A technical overview

2.7 Power Island progression for Black Start

National Grid ESO's Black Start SOF[1] envisages the establishment of distribution-level microgrids (power islands) at 33kV or 11kV level that could eventually restore power to a part of the distribution network as shown in figure 2.4.

The generation sources in the power islands are envisaged to include dispatchable DER such as standby diesel generators and BESS as well as non-dispatchable generation such as small wind farms and commercial and industrial PV systems. The size of the power islands is expected to be tens of MW's and will typically consist of one or more 33kV feeders at a distribution substation.

Figure 2.4 illustrates the position of the power island in relation to the rest of the distribution network. As shown some DER generators and BESS could be outside the planned microgrid.

Once the power island has been established the SOF defines 3 possible progression steps.

- **Stage 1** – The power island remains a self-contained system for the duration of the black-out and waits until supply has been restored from the main transmission network. At that stage, if the POC has a synchronising breaker, the island could be connected to the main supply without interruption. Alternatively, the island would need to be de-energised before reconnection to the rest of the grid. The size of the power island at this stage is expected to be between 1MVA–20MVA in size.
- **Stage 2** – The power island could be expanded by switching in more load and DERs at 33kV level, as shown in figure 2.5, to energise a larger part of the distribution network, provided it had excess generation capacity. It would still remain isolated from the main grid. The size of the power island would grow to become 20MVA–50 MVA in size for example. Growing a power island through clustering is discussed in a following section.
- **Stage 3** – The power island has excess generation capacity which can be exported to the rest of the network to act as a Virtual Power Plant (VPP). At this stage the power island would become connected to the 132kV or even the transmission network. Realistically this scenario would only be feasible if the microgrid had generating capacity of 50 MVA or more, and it could manage the non-critical load on the microgrid so that it had sufficient excess generation capacity to connect load outside the microgrid.

Whereas a power island typically has a confined network boundary, VPPs can stretch over a much wider geographical area which can grow or shrink depending on the power system requirements.

This report predominately focuses on Stage 1 of the progression, and aims to identify and explore the operational challenges with regards to maintaining microgrid strength and stability in presence of high shares of converter connected DERs.

Figure 2.4
Power Island in relation to the rest of the network [1]

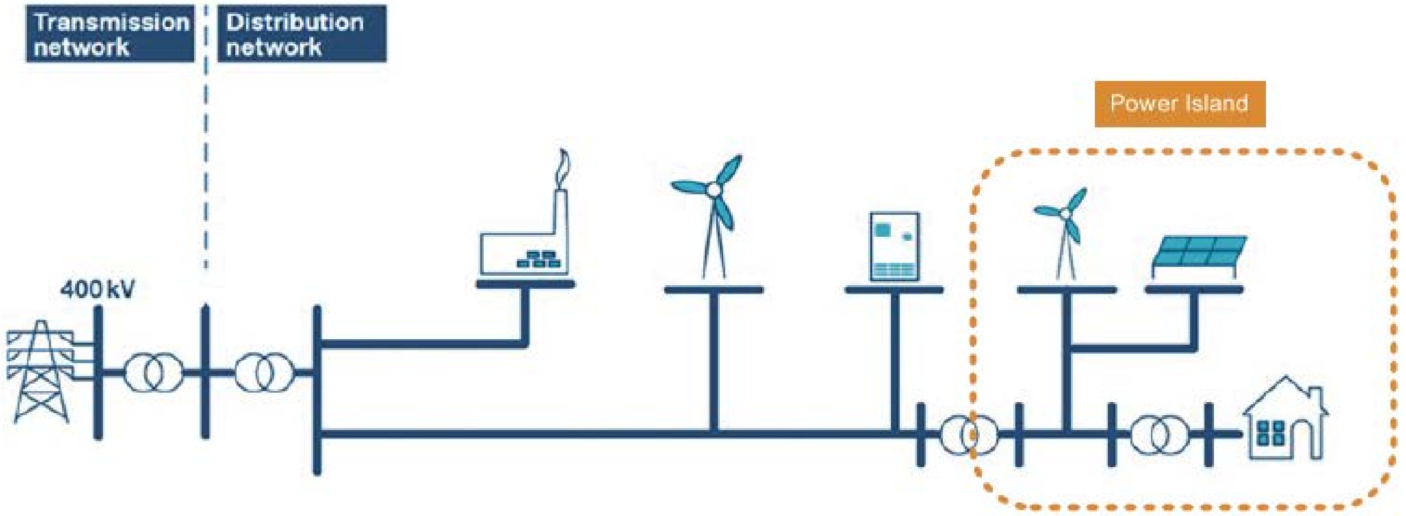


Figure 2.5
Expansion of the Power Island [1]

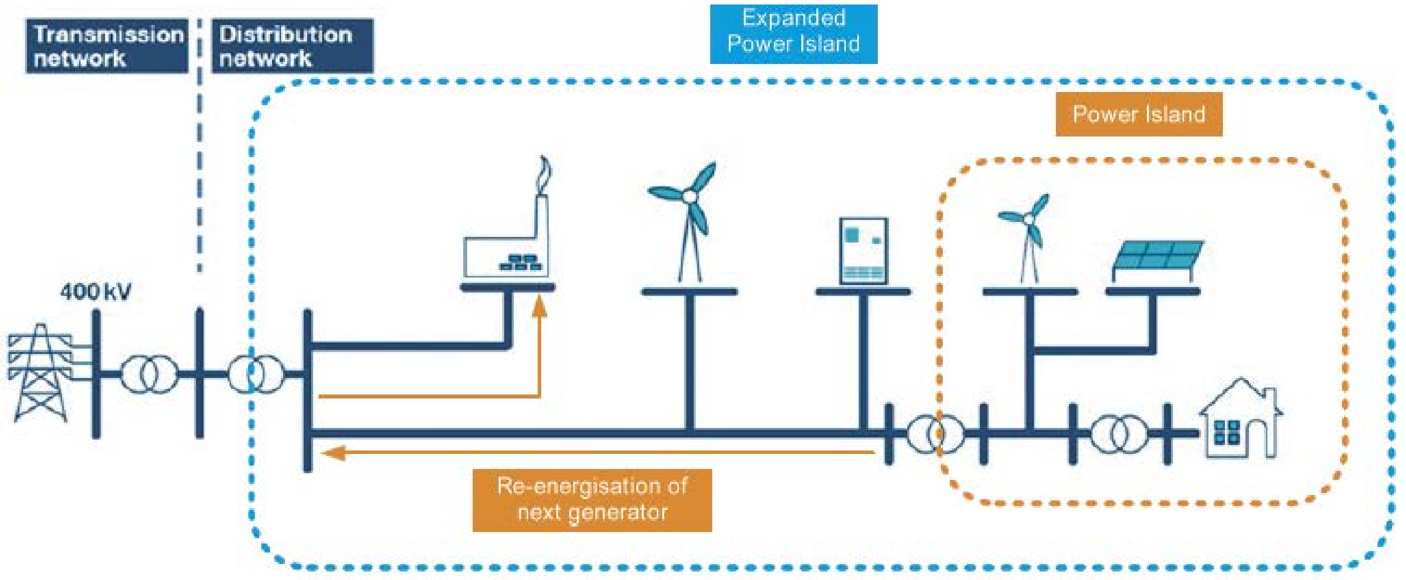
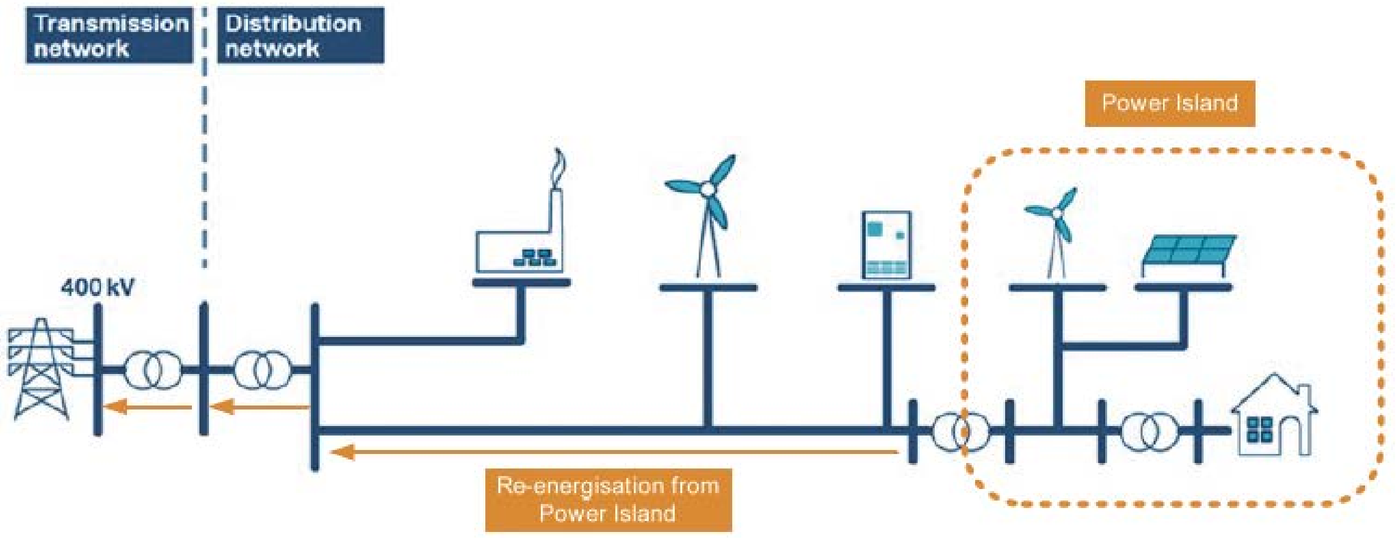


Figure 2.6
Re-energisation the rest of the network from the power island [1]



2 Microgrids – A technical overview

2.8 Clustering of microgrids

During a partial or total shutdown scenario, independent microgrids/power islands may fail to support their own loads due to the intermittency of renewable energy sources affected by variable wind or sun, or sudden changes in load.

The sensitivity of such power islands can be mitigated by interconnecting several microgrids to form a larger power island [17]. Practically this could be done by switching distribution feeders at different substations to electrically connect the microgrids.

In a cluster of microgrids, one microgrid needs to act as a slack bus to regulate the frequency. Ideally, in order to ensure stability of the group of interconnected microgrids the slack bus should have a large synchronous generator (e.g. diesel generator) with high inertia and excess energy. The other microgrids connected at the different buses shall act as 'PV' (generation) or 'PQ' (load) buses based on the type of resources they have.

The interconnection of microgrids requires reliable communication and control systems. When the microgrids are established, either through automatic islanding from the grid, or by means of grid-formation following the shutdown, they should be able to communicate with each other to confirm that all of them detected the shutdown.

Through pre-configuration one of the microgrids would act as the slack bus or the master microgrid. Its microgrid controller would act as the master controller and determine which of the other microgrids has the most available energy to make the cluster of microgrids more stable. Through fully functional smart grid functionality and communication the microgrids then determine how to share or disconnect load between them based on available energy. Strong co-ordination between the DNO/DSO and the master microgrid controller will be essential.

Different microgrid control hierarchies and control sequences exist, but their discussion is beyond the scope of this report. Essentially, microgrids can grow in size through clustering of individual microgrids, however a reliable and resilient control and communication system is a pre-requisite for its functioning.

3 Microgrid operating challenges

3.1 Microgrid characteristics

Microgrids have several characteristics which distinguish them from the larger power grid. The main characteristic differences include [15]:

- A higher share of renewable energy resources (RES), in particular wind and solar, on microgrids compared to the main transmission and distribution grid. This is a result of the ongoing proliferation of renewable energy resources connecting on the MV and LV grid by plant owners to decarbonise, reduce energy costs and provide network ancillary services. At the same time the number of dispatchable diesel or gas generators on MV/LV networks which are typically used for standby capacity are remaining constant. Renewable resources such as wind and solar are highly intermittent, which results in the generation on microgrids having a high intermittency and low dispatchability.
- The share of converter-connected DERs on microgrids can be very high with penetration levels up to 100%, as evident in one the case studies reviewed in a later section. The majority of wind and solar converters are current-limited voltage source converters that are typically configured to produce maximum power without contributing to frequency or voltage regulation. BESS are usually interfaced to the grid using voltage-controlled voltage source converters, which has the ability to set frequency and voltage at its output [6]. The synchronous generation on a power island is usually provided by one or more thermal generators which could be diesel, gas, biomass or waste-to-energy plants.
- A microgrid/power island network is a lot smaller size compared to a distribution network, and the 11kV and 33kV circuits are relatively short compared to the longer higher voltage lines on the distribution and transmission network. The short microgrid feeders have a much lower reactance to resistance (X/R) ratio compared to the main power grid.

3 Microgrid operating challenges

3.2 System consequences

The above-mentioned characteristics have a number of technical consequences for the strength and stability of microgrid power systems.

3.2.1 High variability of load and generation

For a power system to be stable, generation and demand (active and reactive power) have to be closely matched and balanced. Large power systems have the benefits of customer load diversity which smooths customer load, large dispatchable generation which can be called upon when a generator falls away, and geographic diversity which leads to a higher availability of wind / solar generation.

Microgrids tend to have one or more synchronous diesel or gas generators as anchor generators which can provide a stable voltage and frequency source. These need to be run at a certain minimum power output level to prevent long-term damage to the machines, which can make for costly operation.

The balance of the generation tends to be increasingly supplied by renewable energy sources such as wind and solar, the output of which are dependent on climate and weather factors such as wind speed and cloud cover. A large share of the power generated on a microgrid is therefore highly variable.

Furthermore, customer loads on a microgrid tend to be more variable than on a larger grid due to the small numbers and lack of diversity. A microgrid power system typically consists of a few MV feeders, and the loss of a single feeder can result in a loss of a large share of the load.

Other factors that can contribute to the variability of generation and demand include:

- loss of generating units;
- poor power sharing between DERs resulting in unbalanced loads;
- incorrect selection of slack resources; and
- incorrect no-fault load tripping due to incorrect protection settings.

3.2.2 Low system inertia

System inertia is a function of the number of operating synchronous generators and the inertia of the generators and can be described as the amount of kinetic energy stored in the rotating parts of the machines connected to the power system. The inertia constant for various synchronous machines is provided in table 3.1.

Table 3.1

Inertia constant for different synchronous machines types [40]

Machine	*H* (s)	Machine	*H* (s)
Turbine generator	3–9	Synchronous motor	2.0
Hydraulic unit	2–4	Synchronous condenser	1.0–1.25

Synchronous generators inherently provide immediate fault level and inertia without the need to measure the electrical grid. When a frequency event occurs, the synchronous machines will inject or absorb kinetic energy into or from the grid to counteract the frequency drop/rise. The inertia in the rotating masses of synchronous generator and turbines therefore determine the immediate frequency response of the power system. The lower the system inertia, the more the system frequency will react on sudden changes in generation and load.

Non-synchronous generators, such as wind turbines or PV plants, are decoupled from the grid via a converter and contribute nothing or very little to the system inertia. Wind turbines have a lot of kinetic energy stored in the blades due to the large rotating mass, and in theory could provide inertia comparable to most synchronous generators [39]. However, contribution to inertia is not a Grid Code requirement for wind turbines, and there are currently no commercial incentives for wind farm operators to sacrifice the wind turbine output power to provide a frequency response to mimic inertia. Therefore, the inertia contribution from wind turbines on most grids is very little. Because solar plants have no moving parts their contribution to system inertia is zero.

According to [39], for a penetration of x % of wind turbines or solar plants, the new power system inertia can be calculated as: Hsystem, new = (1 – x)Hsystem. This implies that if the wind / solar penetration increases by x % the microgrid system inertia will be reduced by the same amount.

Inertia can be particularly low on networks with high renewable penetration when the demand is low, e.g. during the night. With solar plants the generation generally corresponds to periods of high demand, resulting in the solar having less of an impact on inertia than wind, which can occur during periods of both low and high wind. The end result is that microgrids tend to have a much lower inertia than the main power grid. The inertia is dependent on the amount of generation/load on the system and tends to reach its lowest level when the amount of generation and demand is at the lowest levels.

3.2.3 Low Short Circuit Level

The National Grid ESO SOF – Impact of declining short circuit levels report [28] defines Short Circuit Level (SCL) as the amount of current that will flow on the system during fault. The SCL is necessary to maintain a stable voltage during a fault period, which in turn is necessary to inform the Phase-Lock Loop (PLL) of any converter connected generation, so that it knows what is happening on the system, and can adjust its voltage and current output accordingly.

If the SCL is low, the voltage waveform will be more distorted and oscillatory during a fault which can result in the converter PLL not measuring the voltage waveform correctly and potentially disconnecting from the network. The relationship between different levels of SCL and voltage waveform during a network fault is illustrated in figure 3.1 below. It is estimated that the level of voltage distortion will double if the fault level is halved [13].

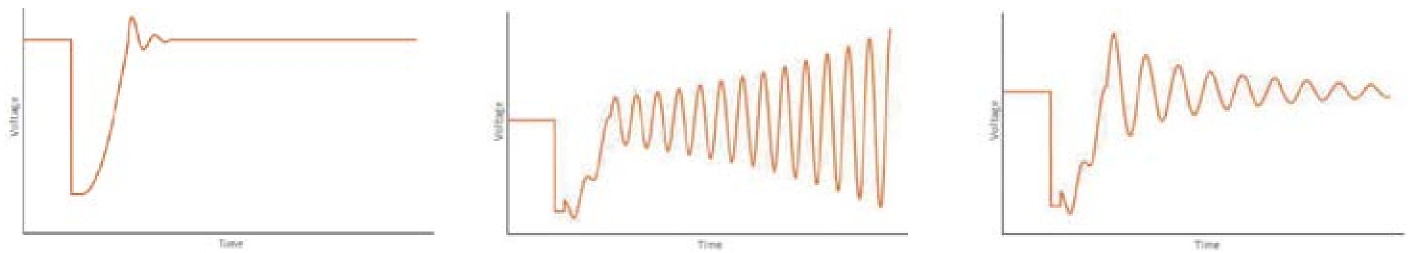
Synchronous generators are a major source of SCL and can typically supply fault currents in the order of 4 to 10 times nominal current [30]. Inverter “impedance” is a function of control, not a physical characteristic.

Fault current is determined by the specifications of the converter module and limited to prevent damage to the power electronic components from the high currents and fast transients. The fault current produced by RES convertors is typically in the range of 1.1–1.5 times the nominal current [29]. The short circuit contribution from converter-connected DERs is therefore insignificant. The result is that the SCL can be quite low on microgrids with high degrees of DERs. A low SCL impacts operability of a microgrid in the following way:

- **Protection** – Lower SCL means that the protection devices (e.g. overcurrent and earth fault protection) may not recognise the current as a fault current and therefore not operate correctly.
- **Voltage** – A lower SCL results in greater and faster voltage variations during a disturbance on the system.
- **Stability** – A lower SCL reduces the “strength” of the system, and it may not return to its normal stable operation following a disturbance.
- **Converter stability** – Increased voltage instability may lead to converter PLLs not measuring the grid correctly resulting in multiple DERs disconnecting from the grid.

Figure 3.1

Impact of different short circuit levels (SCL) on the voltage waveform [28]



3 Microgrid operating challenges

3.2.4 Greater Voltage-Frequency coupling

On distribution and transmission networks with long lines and cables, active power flow and voltage is decoupled due to the reactance of the network. The effect is that long lines/cables are capacitive when power flow is low, resulting in voltage rise. The increase in reactive power would be absorbed through switching in shunt reactors and/or utilising inverter-based VAR control systems such as SVCs, STATCOMs or wind farm inverters.

The same lines/cables would become inductive when the power flow is high, absorbing reactive power from the network and resulting in the voltage reducing. The system operator would respond by switching in capacitor banks and/or instructing SVCs, STATCOMs or inverter-based wind farm to generate the reactive power.

Microgrids by their nature are very small size compared to distribution grids and typically consist of relatively short MV underground cables or overhead lines. These feeders are mostly resistive in nature translating to a low X/R ratio. As a result, active power flow and voltage magnitude are more closely coupled. Furthermore, because of the small size of the network, voltage changes at the DER terminals are almost instantaneously reflected at the load side, resulting in the system demand changing, which in turn impacts the frequency [15].

There is therefore greater voltage-frequency coupling compared to large distribution networks, which can result in strong oscillations between power, voltage and frequency. Microgrids therefore require dynamic and fast voltage and frequency responses to quickly damp such oscillations.

3.2.5 Loss of earth reference

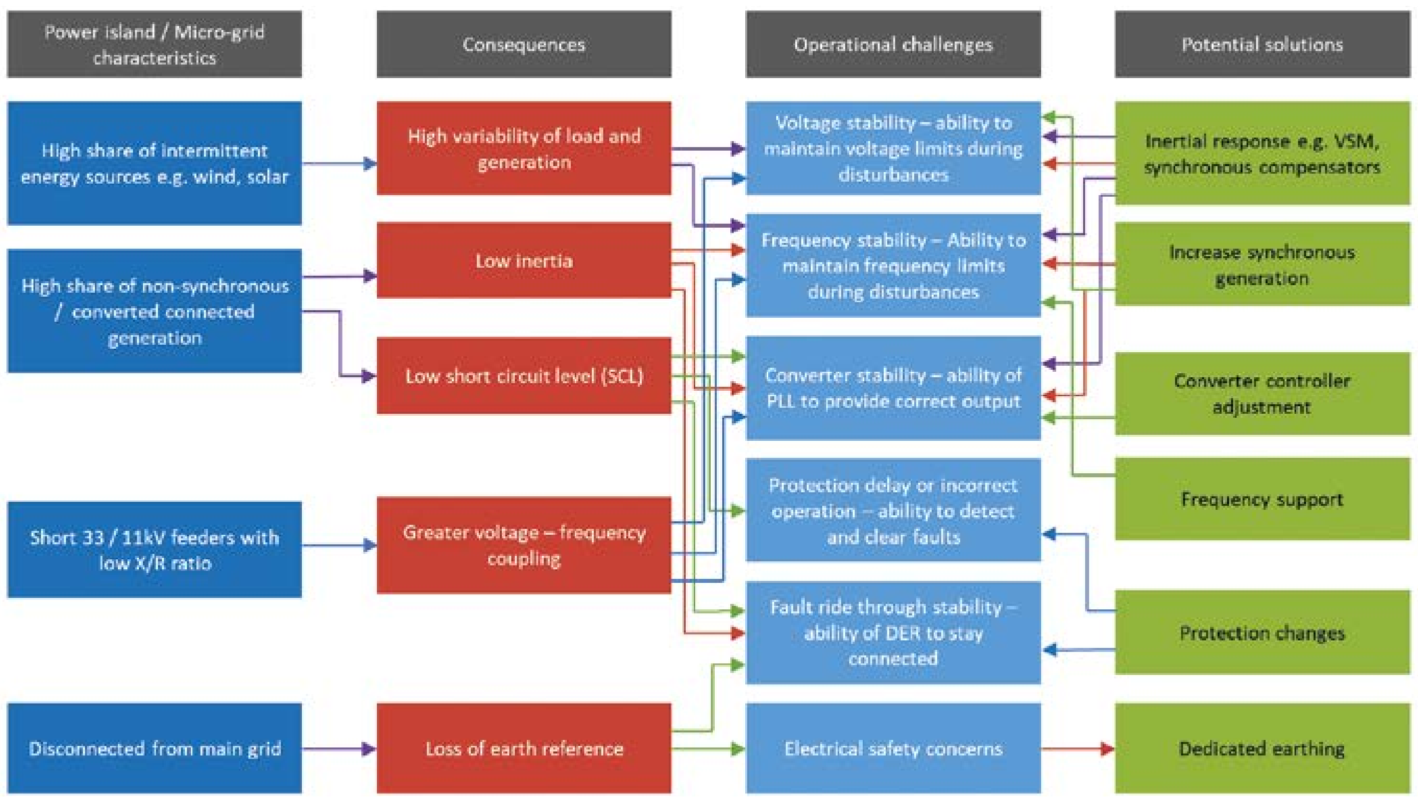
In the UK, MV networks are usually earthed only at the source. This means that 33kV and 11kV feeders would be earthed only at the supply substation on the main grid. If these feeders are disconnected from the substation during a microgrid/power islands scenario, it would result in the microgrid earth being disconnected from the main grid which impacts negatively on the reliable and safe operation of the microgrid.

3.3 Operational and stability challenges

The system consequences present a number of operational challenges that need to be addressed to ensure microgrid stability. The relationship between the microgrid characteristics, consequences and operational challenges are summarised in figure 3.2.

Figure 3.2

Power island/microgrid operational challenges



Each of the challenges in figure 3.1 are explored in detail below.

3.3.1 Voltage stability challenges

Unlike large power systems, where power transfer and voltage stability are influenced by long transmission lines, power islands tend to see relatively small voltage drops between the generators and loads. Weak and old distribution networks may however experience current limitations and voltage drops.

Voltage instability could occur on power islands due to the following:

- sensitivity of load power consumption to supplied voltages;
- poor reactive power sharing between DERs. Any changes in DER terminal voltages are immediately reflected in the rest of the system. Small voltage differences, which if not co-ordinated, could result in circular reactive power flows which could result in large voltage oscillations. It could also result in generator pole slipping in extreme cases;
- sudden large changes in generation due to generation variability; and
- large and sudden changes in demand due to reduced customer load diversity.

Short-term voltage instabilities could result from poor control co-ordination or fast dynamic active/reactive power mismatches. Long-term voltage stability problems could result from DER output limits being gradually reached by a steady increase in demand.

3.3.2 Frequency stability challenges

Potential causes for frequency instability include:

- Large load increases/generator losses followed by an inadequate system response in the absence of low inertia, can lead to rapid frequency decline and protection operation.
- Poor co-ordination between different frequency controllers and power sharing between DER could result in small frequency perturbations which could lead to large frequency oscillations lasting up to several minutes depending on the protection schemes.
- Insufficient generation reserve may lead to steady-state frequency being outside the normal range resulting in Low Frequency Demand Disconnection (LFDD) relays operating and tripping of load.

Frequency stability is a major concern in power islands due to the low system inertia resulting from the high ratio of convertor-connected DERs compared to synchronous generators, and the high share of intermittent DERs. Also, the low number of generators in the power island can easily result in large disturbances when generators are disconnected.

Network disturbances on microgrids are therefore likely to result in rapid frequency changes or high Rate of Change of Frequency (ROCOF) events. Wind and solar plants have ROCOF protection to protect against islanding, and a ROCOF event on the system could result in a cascading effect of DERs disconnecting. Conventional frequency control techniques may not be fast enough to respond to the fast frequency change, even if sufficient generation reserve exists.

Low system inertia does not only contribute to a high ROCOF, but also to higher and lower frequencies during the frequency disturbance, i.e. larger frequency deviation. With a high DER share, the minimum frequency could trigger demand disconnection or a black-out of the power island.

Frequency regulation is also complicated by the voltage – frequency coupling characteristic discussed in 3.2.4.

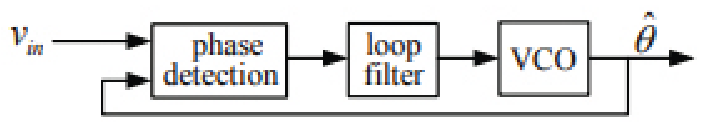
3.3.3 Converter controller stability challenges

Conventional converter controllers are current controlled – voltage source converters which follow the existing system voltage and are usually operated in maximum power point tracking mode so power production from the renewable resource is optimised. The converters use a Phase-locked Loop (PLL) process to synchronise with the system voltage.

The basic structure and operation of a close loop PLL is shown in figure 3.3. In simplistic terms it measures the difference in phase angle between the network voltage waveform (the input) and the converter output signal. This is passed through a loop filter which drives the voltage-controlled oscillator (VCO) to generate the converter output voltage to follow the input signal.

Figure 3.3

Functional diagram of a basic PLL [11]



Up to 13 different PLL techniques are identified in [11] each with unique attributes in terms of complexity of design, response speed, distortion insensitivity and unbalance sensitivity.

3 Microgrid operating challenges

Traditional PLL operation assumes connection of the inverter controller to a strong distribution or transmission network with lots of synchronous generation with high inertia and a stable system voltage during disturbances. However, on microgrids with a low share of synchronous generation and high share of intermittent converter-connected generators, network voltage is more dynamic. During network disturbances the voltage waveform is also a lot less stable which can lead to the PLL losing track of the voltage and its output becoming unstable. The risk is damage to equipment and loss of the generator.

The potential instability of converter controllers in weak transmission networks is well documented in the System Operability Framework "Performance of Phase-Locked Loop Based Converters" [9]. The relevant conclusions which can be drawn for microgrids are that:

- conventional PLL inverter controllers are prone to instability on weak power networks because the voltage waveform can be highly variable during disturbances as a result of low SCL and low system inertia.
- the exact response of converter controllers to disturbances is difficult to predict beforehand as most converter models used in power system simulations are only generic. As mentioned above there are numerous PLL methodologies and the design and detail are unique to each manufacturer resulting in distinctive behaviour.
- a minimum SCL is required for the normal operation of converter connected non-synchronous generators. The minimum level would need to be determined through power system analysis with the specific converter controller model.
- the distance of the fault from the converter influences the converter response. For a fault at the converter terminals the reference voltage drops to zero, and the PLL continues following its phase position and remains stable. However, for a fault at a remote location, a small retained voltage remains at the DER terminals which the PLL continues to track as the system voltage. When the fault is cleared, and the system voltage is re-established, the PLL fails to track the network phase across the phase jump, and the converter controller becomes unstable (as per the example in figure 3.4. The fault ride-through capability of a PLL converter is determined by the magnitude of the retained voltage as well as the range of phase change required to recover the voltage. The Grid Code compliance tests for converters focus only on the magnitude of the voltage change, and not the phase change required, which is a shortcoming.

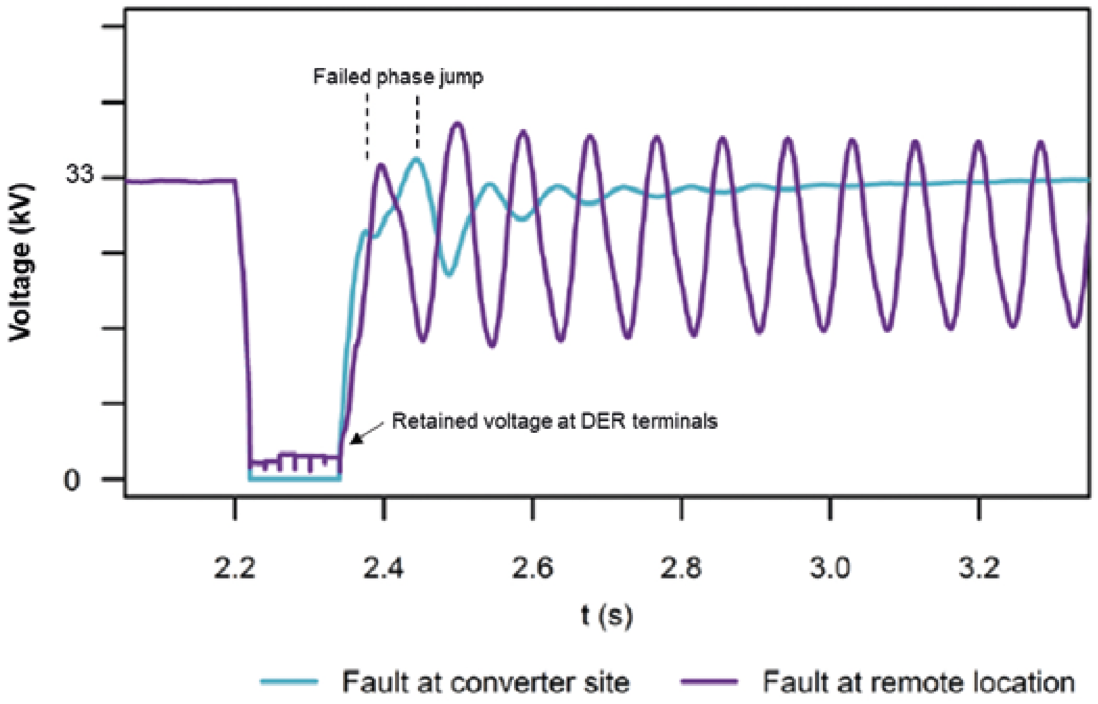
In addition to the above challenges, [15] also highlights conditions which could lead to harmonic instability of the converters. This includes:

- converter inner voltage and control loops which are not tuned correctly can result in high harmonic-frequency oscillations
- several inverters in close distance could generate interaction problems resulting in multi-resonance peaks
- high frequency switching could trigger the resonance of the inverter LCL filter.

Harmonic stability can be mitigated by active damping strategies [15].

Figure 3.4

Failure to track the phase jump due to retained voltage at converter terminals [9]



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3.3.4 Protection operation challenges

The 2016 version of the European "Network Code on Requirements for Grid Connection Applicable to All Generators" [31] and the Great Britain "Grid Code" published by National Grid ESO in April 2019 [32] state that all generating units should be capable of providing fast symmetrical fault current during a symmetrical network fault. However, the fault response for converter units is not specified in detail and left open to be specified and agreed between the system operator and the plant owner.

Usually fault currents in the range of 5 p.u.–10 p.u. are required to trigger overcurrent fault protection. As mentioned earlier the short circuit current contribution from converter connected DERs generators is typically limited by design to between 1 p.u–1.2 p.u. of the rated load current to protect the power electronics.

The fault response of converter-based generators is directly influenced by the control strategies adopted in the converter. Most converters are current-controlled voltage source converters (VSCs), which means that the converter will act as a constant current source during faults.

The fault current consists of two components:

- an initial inception current which can be as high as 2.5 p.u., but which lasts only from a quarter to two cycles
- low magnitude fault (1 p.u.–1.2 p.u.) lasting only 100ms.

Furthermore, the fault current is programmed to be mostly positive sequence with negligible negative or zero-sequence components.

The challenges experienced by protection systems on microgrids include the following: [36]

- directional protection relays may not perform reliably due to the low magnitude of the negative sequence current and voltages being too low
- phase and ground overcurrent relays need to be set sensitive enough to detect faults (due to the lack of fault current contributions by converters), but not too low that it trips during normal conditions
- phase distance protection may not operate reliably because the minimum available fault current may be outside the minimum detection range of the relay
- Low Frequency Demand Disconnection (LFDD). Due to lower system inertia, frequency decay is more rapid following loss of generation resulting in a high ROCOF, which could result in LFDD being activated and the unintended disconnection of generators from the microgrid.

3.3.5 Fault ride-through stability challenges

G99 and the Grid Code [42] provides the fault ride-through requirements for generators greater than 1 MW (i.e. Type B–D generators) for faults on the transmission network. However, due to low short circuit levels on microgrids, the frequency change and extent of frequency deviation will be more severe than on strong networks. The magnitude of voltage dips following a fault will also be severe and the ability of DERs to ride through low/high voltage transients and to properly disconnect during unintentional islanding scenarios will be more challenging.

The overall objective is that the DERs should not disconnect from the microgrid, unless there is a material disturbance on the microgrid, as disconnecting generation will only tend to make an under-voltage situation worse. Detailed system studies using accurate convertor models are required to determine the expected magnitude of voltage dips on a particular microgrid, which should then be used to determine the fault-ride through protection settings.

3.3.6 Electrical safety concerns

The main electrical safety concern relates to disconnection of the main grid earth when the micro-grid is operated in island mode, and the requirement for a suitable earth arrangement to be made.

3 Microgrid operating challenges

3.4 Improving microgrid strength and stability

3.4.1 Inertial responses

As discussed previously, microgrids tend to have low inertia which increases risk of voltage and frequency instability during disturbances and also leads to deeper frequency dips compared to (normal) power grids with higher shares of synchronous generators.

Low inertia can be mitigated in one of 3 ways:

1. addition of synchronous compensators;
2. exchanging kinetic energy from wind turbines; and
3. synthetic inertia from BESS.

3.4.1.1 Synchronous compensators

Inertia could be improved by adding synchronous compensators which increase SCL on networks. A typical synchronous condenser could provide 5 p.u. fault current compared to a maximum fault current of a wind farm of 1.5 p.u. In the case of a 30MW wind farm, the fault current contribution from the wind turbine generators would be 45 MVA. Another 105 MVA would be needed to reach 5 p.u. fault current. This could be provided by a synchronous condenser of 105/5 = 21 MVA in size. However, synchronous condensers are expensive and installing them on microgrids is unlikely to be feasible.

3.4.1.2 Synthetic inertia provided by wind turbines

The effects of low inertia can also be mitigated by implementing advanced control strategies to make converter-controlled energy systems behave in ways that are similar to synchronous generators by using system frequency as one of the inputs and controlled variables. This is known as synthetic inertia. Converter-connected generators operating to provide synthetic inertia are known as virtual synchronous machines (VSM).

Wind turbines have a lot of kinetic energy stored in the blades due to the large rotating mass, and in theory can provide inertia comparable to most synchronous generators [39]. However, there are some differences with respect to how their kinetic energy can be used for frequency control.

- The kinetic energy stored in a wind turbine is not constant, and changes with wind speed, compared to a conventional generator where kinetic energy remains almost constant.
- The release of energy from a wind turbine can be controlled independent of the ROCOF, meaning that in principle it could provide a larger inertial response than a conventional generator which has a strong coupling between the rotor speed and the frequency resulting in a proportional relationship between kinetic energy released and ROCOF.

Many inertia control methods have been developed for wind turbines to enable inertial response [37]. The main methods include:

1. Including df/dt into the power control. A supplementary control signal associated with the grid frequency variation measurement is applied to the torque/power control. As grid frequency drops, the modified set point torque is increased, slowing the rotor and extracting the stored kinetic energy.
2. Virtual synchronous control. The magnitude and phase of the converter's output voltage is determined based on the active and reactive power errors. The PLL is effectively removed, which means that the wind turbines can operate more stably in weak grids. However, very large disturbances can result in very sharp inertial responses which can negatively impact wind turbine safety and stability.

Several other control methods also exist and are summarised in table 3.2 for information. As shown each method has its own advantages and disadvantages and the method finally selected should be influenced by an assessment of the following considerations [37]:

- impact of mechanical loading and stress placed on the wind turbine when it is electromagnetically coupled with the grid;
- co-ordination between inertia control and turbine control to avoid a secondary frequency decline when the turbine needs to speed up again;
- the wind turbine's inertial response should be studied to determine suitability for the microgrid before final selection;
- the interaction between fault ride-through and inertia control should be analysed and coordinated; and
- the inertial response from multiple wind turbines should be studied and evaluated to avoid clashing and competition between plant.

Table 3.2

Major characteristics of main inertia control methods for wind turbines [37]

Control Methods	Response Delay	Response Characteristics	Implemented Complexity	Additional Sensed Variables	Main Technical Barriers and Potential Risks
df/dt method	Inevitable	Close-loop feedback control	Medium	Grid frequency	Complicated parameters setting Easy to cause the power fluctuations
Δf method	Inevitable	Close-loop feedback control	Simple	Grid frequency	Excessive inertial response of the wind turbine Conflict with primary frequency regulation of power system
Enercon IE	Inevitable	Close-loop feedback control	Very simple	Grid frequency	Conflict with primary frequency regulation of power system
Frequency deviation trigger	Inevitable	Open-loop feedback control	Very simple	Grid frequency	Excessive power support with large-scale integration of wind turbines Conflict with primary frequency regulation of power system
Optimizing *PLL*	No	Open-loop natural response	No modification	No	Easy to cause the power fluctuations Influence the response of the other control loops Excessive inertial response of the wind turbine
Virtual synchronous control	No	Open-loop natural response	Complexity	No	Altering the control structure of the wind turbine Fault tolerance Excessive inertial response of the wind turbine

3.4.1.3 Synthetic inertia from battery energy storage systems

BESS are able to provide synthetic (or "digital") inertia by very fast active control (milliseconds or tens of milliseconds) to replace the inertia traditionally supplied by synchronous generators. BESS reaction times to faults are approaching 0.1 seconds. Although slower than synchronous generators which can respond within 0.05 seconds, BESS can respond dynamically with very high ramp rates. For example, batteries can delivery full output in less than 0.2 seconds and can sustain this for minutes to hours depending on the size of the battery [41].

Through a two-year research project, funded by the UK Government, Northern Ireland's Queens University Belfast (QUB) studied operating data from a 10MW Energy Storage Array in Carrickfergus, Northern Ireland. By modelling the energy storage array's impact at scale, the QUB team found that the array's response time – approaching 0.1s – provided the same effective stabilisation as analogue inertia. This would allow just 360 MW of BESS to provide the equivalent stabilisation to Ireland's all-Island electricity system as would normally be provided by 3,000W of conventional thermal generation. The shift to batteries could potentially save up to €19 million annually and could achieve approximately 1.4 million tonnes of annual CO2 savings.

BESS therefore has the potential to effectively address the low inertia challenges microgrids with high shares of renewable penetration face.

3.4.2 Additional synchronous generation

The challenges related to maintaining voltage and frequency stability in a microgrid with low inertia and SCL could be addressed by adding more synchronous generators or synchronous condensers (discussed in section 3.4.1) to improve the microgrid stability and strength.

Synchronous generation does not necessarily imply diesel or gas generation, but could also include cleaner technologies such as biomass, landfill gas, or waste-to-energy plants. New storage technologies such as liquid-air storage systems, use liquid air stored in tanks to power expansion turbines that drive synchronous generators. This could be used to provide inertia to the system for several hours during a Black Start scenario.

3 Microgrid operating challenges

3.4.3 Converter controller adjustments

One of the challenges mentioned for converter control, is that the PLL may become unstable due to its inability to track voltage during network disturbances as a result low fault level, voltage waveform oscillation, or distance of the fault from the converter and harmonics.

The PLL proportional/integral gains can be adjusted or tuned for optimal performance on a specific network. However, in tuning a PLL there is generally a trade-off between filtering and transient response. In other words, by including filters so that the PLL can respond better to unstable voltages as found on weaker networks, its transient response is slowed down. A slower PLL effectively ignores rapid disturbances resulting in better voltage performance for all faults. The downside is that it may not may not respond very well to phase or frequency changes, and control phase-jumps can result in instability.

If a PLL is tuned for faster transient responses by increasing its bandwidth, it will respond better to fast phase or frequency changes, but will be less effective in tracking the voltage on a network with high frequency deviations [35] . On a strong power system, a faster response would enable the PLL to capture the system voltage during the disturbance improving its response and stability. On heavy loaded networks a slow PLL response may result in instability. Therefore, for the best performance the PLL response characteristic should be dynamically adjustable based on the change in network strength [9]. This is manufacturer dependent.

Traditionally converter controllers have been configured and filters installed to limit the emission of their own generated harmonics, however the converters can also be configured and tuned to actively contribute to better voltage quality. Changes in the converter design and software could be made to encourage the harmonic and imbalance currents produced by the converter to positively counter system voltage imperfections [13].

Currently planners and system operators are forced to use generic PLL models with RMS responses, as the PLL models are considered proprietary by most manufacturers. Unfortunately, generic models cannot accurately simulate the response of the converter controllers to network disturbances, which limits the ability to tune or adjust the PLLs to determine the optimum converter response for a particular network.

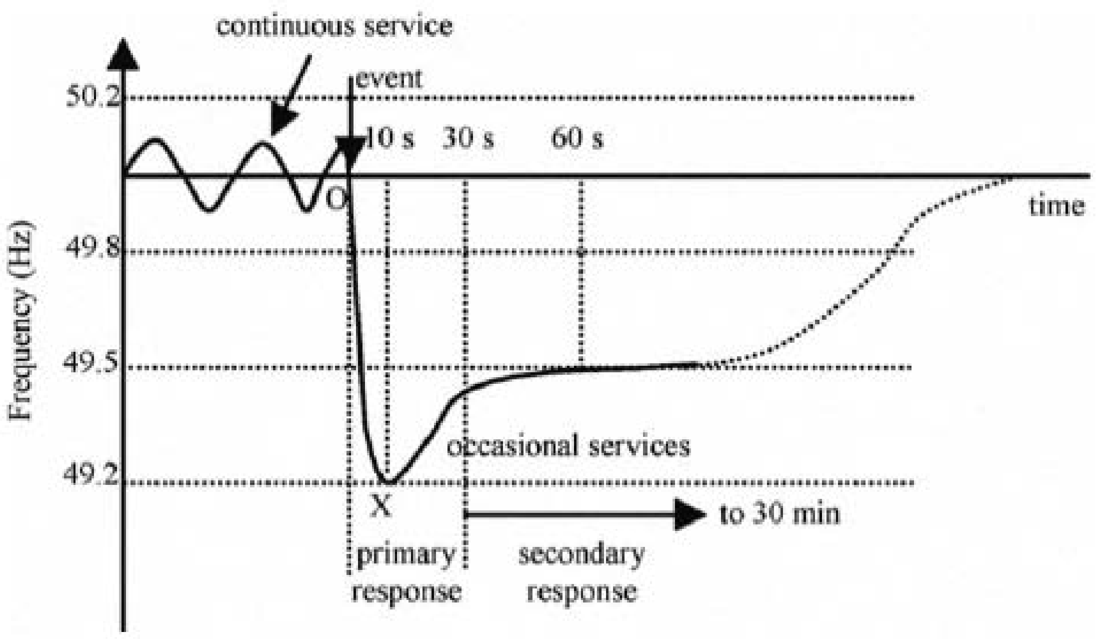
3.4.4 Frequency support

The National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) specifies that the system frequency of the GB grids should not exceed 50Hz by more than ± 1% (± 0.5 Hz) under normal operating conditions. National Grid ESO has set its own operational limits to ±0.4% (±0.2 Hz). [40] This is shown in figure 3.5.

Primary frequency control is provided within 10s–30s. Synchronous generators provide power output proportional to the deviation in frequency to stabilise the system frequency, but not restoring it to the nominal frequency. After approximately 30s generating units in the area of the imbalance contribute to secondary frequency control to restore the frequency to its set point value.

Figure 3.5

Frequency control in the GB system



Literature defines several methods to provide primary and secondary frequency support in a network with a high share of renewables. On microgrids the main methods include:

1 The addition of BESS to PV or wind farms. Coordinated control is necessary between the BESS and the PV/wind farm converters to optimise power output and frequency support. It's been demonstrated to provide both primary frequency response and fast frequency response [36].

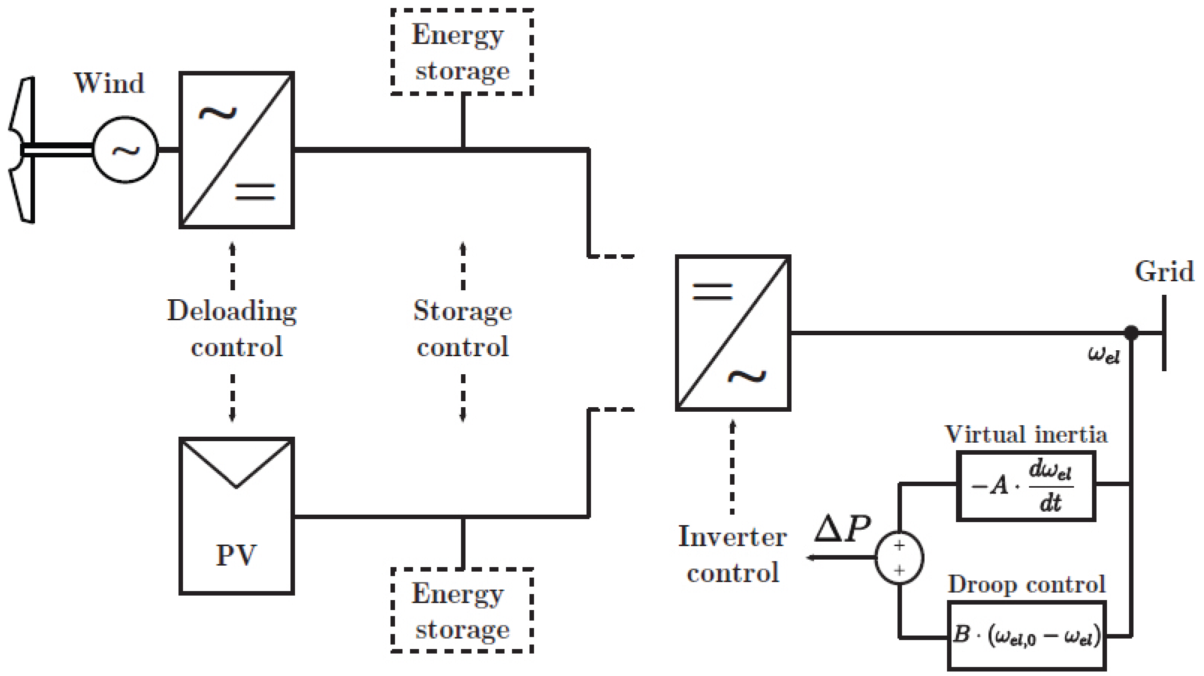
2 De-loading or curtailment of the wind turbines or PV units to provide headroom for frequency control (as in the case of Ireland). The benefit of this approach is that the frequency control can be provided over a longer period of time and the plant can therefore participate in primary and secondary frequency control like conventional generators. However, operating renewable generators at below their maximum output power points is expensive.

3 Demand side response (DSR) could be used on the load side to switch in a voltage-independent load to support the frequency.

An alternative approach to de-loading wind turbines to provide frequency control involves adding additional energy storage and co-ordinating control between the converters, the energy storage and the de-loading of the units [39] as shown in figure 3.6.

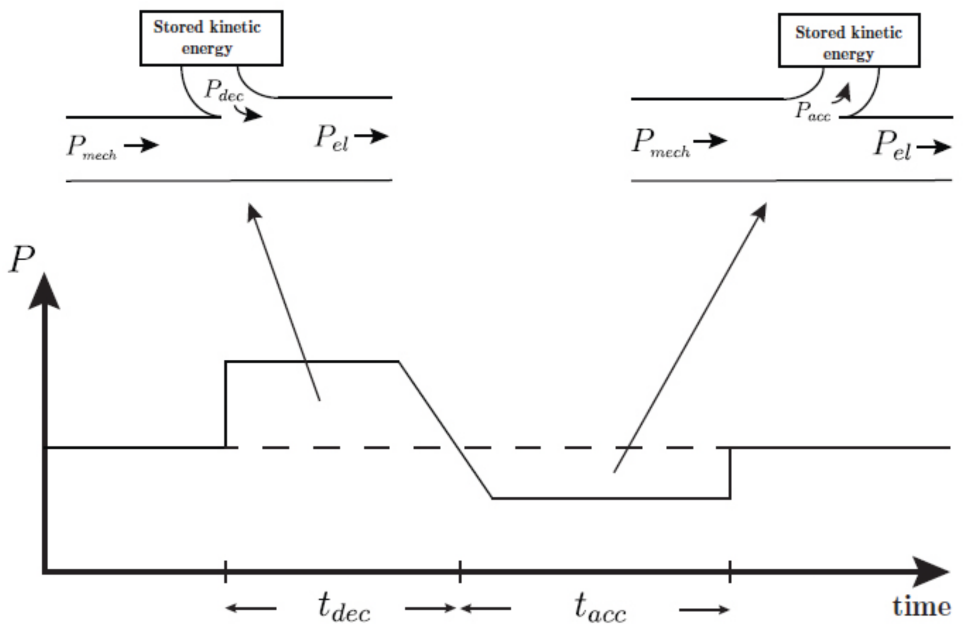
Figure 3.6

Frequency support by combining wind turbines and energy storage [39]



3 Microgrid operating challenges

Figure 3.7
Frequency control by wind farms by exchanging kinetic energy



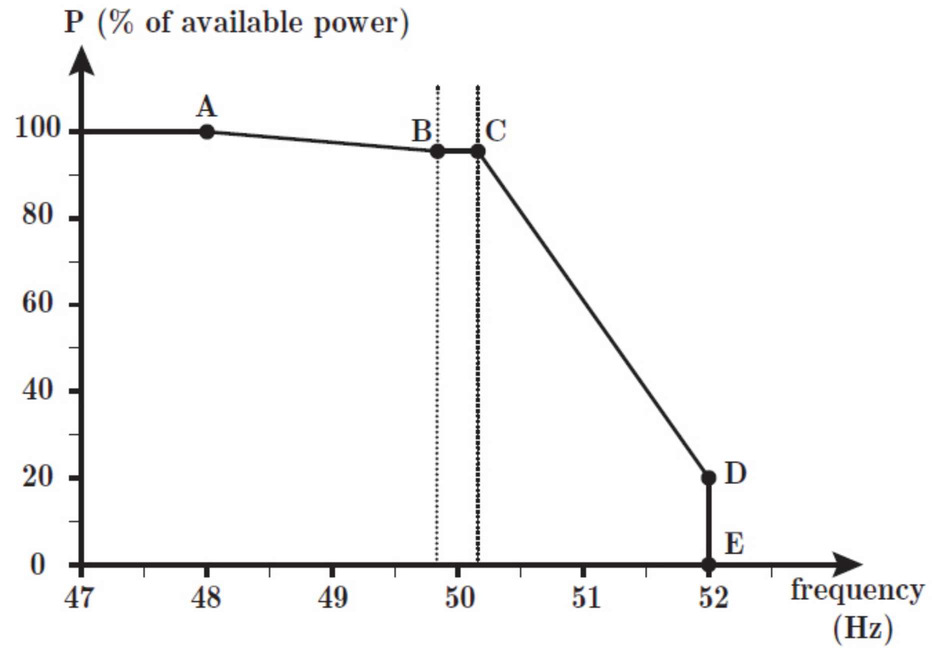
The kinetic energy of wind farms could be used to support the frequency by raising its power output during tdec to provide frequency support as shown in figure 3.7. The rotor speed would drop. To return the rotor to its normal operating speed the turbine's output power would decrease.

The benefit of this approach, compared to virtual synchronous control is that it's not necessary to permanently curtail the turbine output during normal operations. The drawback is that the frequency support can only be delivered for a short time, and a secondary frequency dip could occur during tacc when the turbine power is decreased. Furthermore, the additional mechanical stresses on the wind turbine would need to be weighed up against the frequency support benefit that is gained [39],[40].

In Ireland, the TSO requires wind power plants to behave as close as possible to conventional generators, and to de-load at nominal frequency and request a frequency response [39] in the case of low frequency. As the frequency falls below point B in figure 3.8, the turbines need to respond by ramping up the active power output in accordance with the droop characteristic defined by the line A–B.

Currently the GB Grid Code [42] only requires wind turbines to provide a high frequency response, and does not require wind turbines to provide a low frequency response, hence there is no incentive for wind farm operators to operate their plants in a frequency control mode while sacrificing output power.

Figure 3.8
Power-frequency capability chart of wind turbines in Ireland [39]



3.4.5 Protection changes

Due to low short circuit fault levels, protection problems such as tripping delays, loss of discrimination and the inability to detect unbalanced faults has been reported on grids with low SCL [13].

Mitigation solutions include new relay algorithms, the use of more differential protection schemes, and the enhancement of models used for protection studies. The use of differential protection schemes is considered a last resort strategy as it may necessitate the replacement of existing installed protection schemes, which would be costly.

The most effective short-term mitigation strategy would be to enhance converter controllers so that they contribute the fault currents required by the protection schemes. This includes [36]:

- Programming the converter controller to provide negative sequence fault current instead of just positive sequence fault current. This would improve the reliability of directional protection relays.
- Adjusting the settings in phase and ground overcurrent relays to discriminate correctly between load and fault current correctly, based on validation of the phase currents available for phase-to-phase and phase-to-ground faults. This will require an accurate model of the converter for short-circuit analysis.
- Use of distance protection which relies on voltage and current measurements and is less sensitive to a small difference between load and fault currents. However, the fault current would need to be within the minimum detection ranges of the relay, and this would need to be verified.
- Reconfiguring LFDD relays to accommodate the higher levels of ROCOF expected in microgrids. On typical power grid ROCOF relays are usually set between 0.1 and 1 Hz/s depending on the specific inertia characteristic. As the amount of renewable energy sources increases, as in the case of Ireland, the ROCOF needs to be increased to prevent large scale disconnection of DERs during frequency disturbances. Additional communication systems using fibre will be needed to inhibit LFDD tripping when the microgrid is in island mode.

It is also important that the contribution of fault current in the case of asymmetrical faults must be specified by the network operator in the connection agreement [13].

3.4.6 Dedicated earthing

A dedicated earthing arrangement is required for all microgrids to ensure the safety of persons and property. The earthing installation should conform to the applicable standards, IEC 62257-5 "Recommendations for renewable energy and hybrid systems for rural electrification – Part 5: Protection against electrical hazards." and EC 61936 "Power installations exceeding 1 kV a.c. – Part 1: Common rules" for MV microgrids.

The earthing of equipment in the microgrid should be compatible with the earthing system of the main distribution network to ensure safe operation in the grid-connected mode, island mode and during mode transferring [2]. An earthing transformer or switched star-point earth could be used.

4 Microgrid case studies

A literature review of microgrid projects with high shares of renewable energy resources found that most documented projects were laboratory-based for the purpose of testing various technologies and innovative control systems. The results from these projects were well documented, but not very useful in terms of providing learnings from real-world experience.

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Instead, commercial microgrids were identified and selected, where the experience and measurements were sufficiently publicised to address some of the questions related to the operation of microgrids. The following case studies were initially identified:

1. Flores Island, Azores – Completely isolated MV power system with a peak load of 2.2 MW. 50 per cent of the load is supplied by a combination of hydro and wind generation. A flywheel energy storage system is installed for frequency response, and the possibility of using EVs for Vehicle-2-Grid (V2G) applications is investigated.
2. Island of St. Eustatius, Caribbean – Completely isolated MV power system with a peak load of 2 MW, of 46 per cent–54 per cent is supplied by a solar-battery system.
3. Orkney island, Scotland – Grid connected microgrid run as a smart grid using an ANM (Active Network Management) system. The power grid on the island is managed by a DNO.

The first two case studies are isolated microgrids, which means that they are not connected to a larger power grid. Although there are no learnings in terms of separating and reconnecting to the main power grid, they do provide valuable lessons about the successful integration of large shares of renewable energy into a microgrid, and overcoming some of the operational challenges such as low inertia and SCL.

The Orkney Islands case study was considered relevant, seeing that it was one of the first smart grids in the UK, and because its integration of battery energy storage, community wind generation plants and ANM is well documented. However, although situated on an island, the Orkney smart grid was not designed to be operated as a power island, and that it remains connected via undersea cables to the Scottish mainland. Its contribution towards learning from the experience of microgrids was therefore minimal, and it was decided not to include the Orkney island project in the report.

4.1 Flores Island, Azores Archipelago, Portugal

(References [21], [22], [23], [24])

4.1.1 Introduction and power system overview

Flores island is one of the islands in the Azores archipelago, located in the middle of the Atlantic Ocean between Europe and North America. Its surface area is about 140 km^2, with a length of just under 17 km and a width of over 12 km. In 2003 it had 3,907 inhabitants. It is the island in the Azores archipelago with the largest penetration of renewable energy and in 2010 49 per cent of all electricity was produced either from hydro or wind power [23].

The island of Flores experienced significant economic growth from 1994 to 2010 in line with the rest of the archipelago which resulted a significant increase in electricity consumption. Around that time the government of Azores developed an ambitious strategy to achieve 50 per cent of electricity production from renewable energy in 2013 and 75 per cent in 2018 on average across the islands.

On Flores this resulted in the utility Electricidade dos Açores (EDA) constructing hydro stations and wind farms to reduce the consumption of diesel fuel for electricity generation. In 2002 2 x 315kW Enercon E-30 wind turbines were installed. By 2013 the generation on the island consisted of the plant shown in table 4.1.

Figure 4.1
Location of the Azores islands relative to Europe

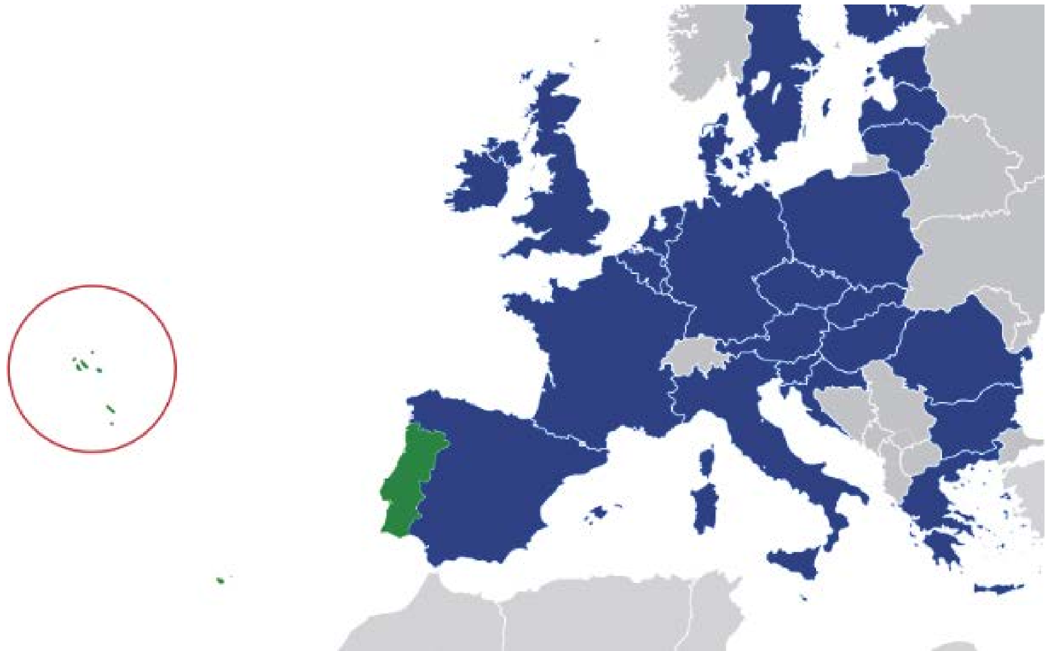


Table 4.1
Generation capacity in Flores Island [24]

Plant	Energy source	Year of installation	Size of generators (kW)	Total capacity (kW)
Além-Fazenda	Diesel	1991	3 x 550 kW + 1 x 810 kW	2,460
Boca da Vereda	Hydro	1996	3 x 250 kW + 1 x 600 kW	1,350
Além-Fazenda	Wind	2002	2 x 315 kW	630
			Total	**4,440**

4 Microgrid case studies

The 15kV electrical grid of Flores Island consists of two substations, one located at the diesel and hydro plant and the other located at the wind farm. The location of the power plants, transmission system and load centres are shown in figure 4.2 and an electrical connection diagram in figure 4.3.

Figure 4.2
Overview of the electrical network on Flores Island [22]

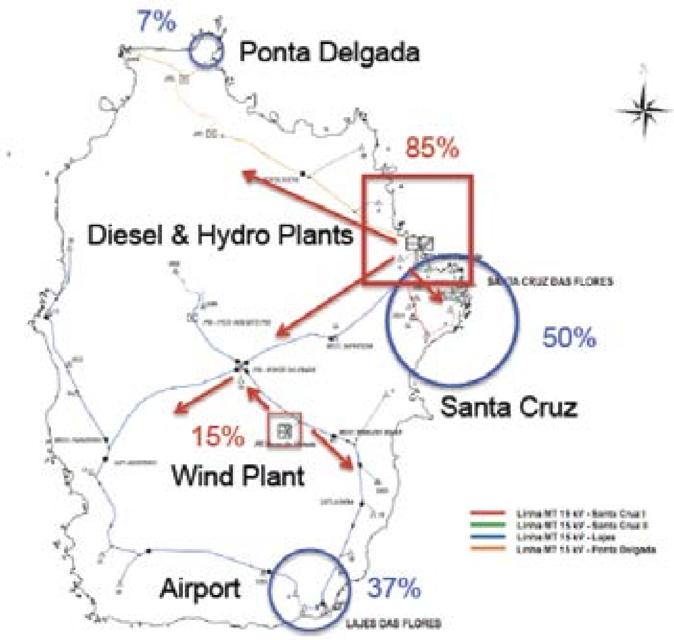
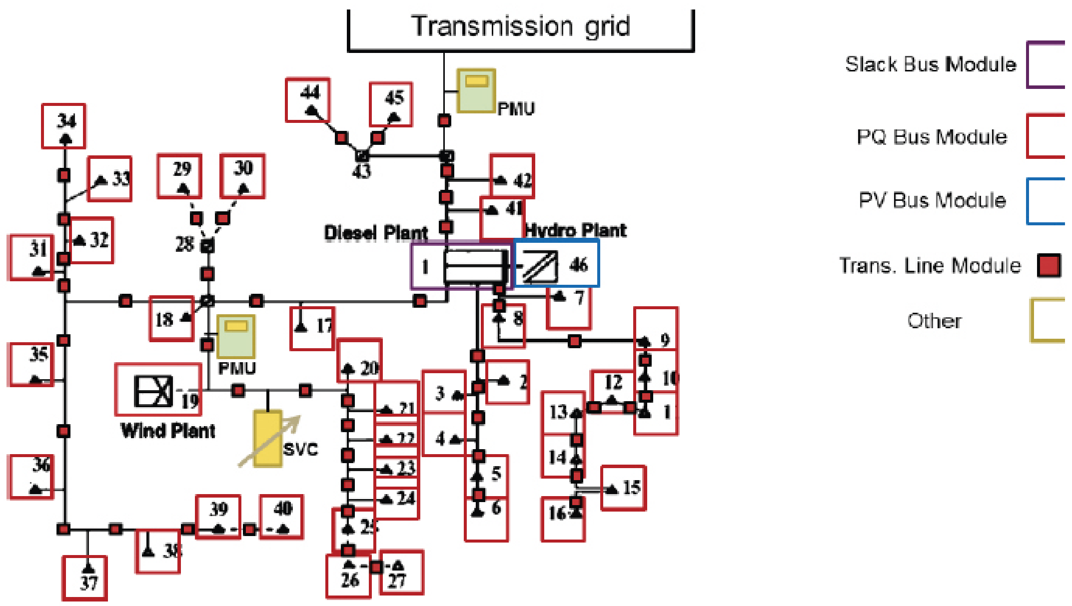


Figure 4.3
Electrical connection of the distribution system [22]



4.1.2 Power system stability challenges

The electricity production profile in figure 4.4 indicates that by 2010 approximately 50 per cent of the energy produced came from renewable sources namely wind and hydro. In 2009 the annual peak load was 2,200kW and the lowest load was 750kW [21].

Figure 4.4
Electricity Production in Flores (2001–2010) [23]

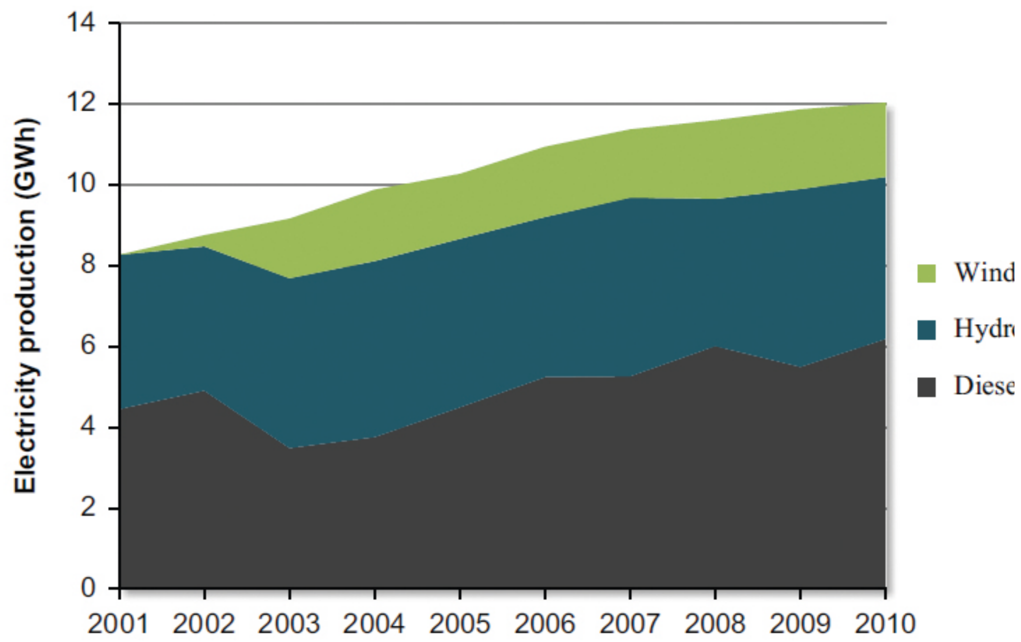
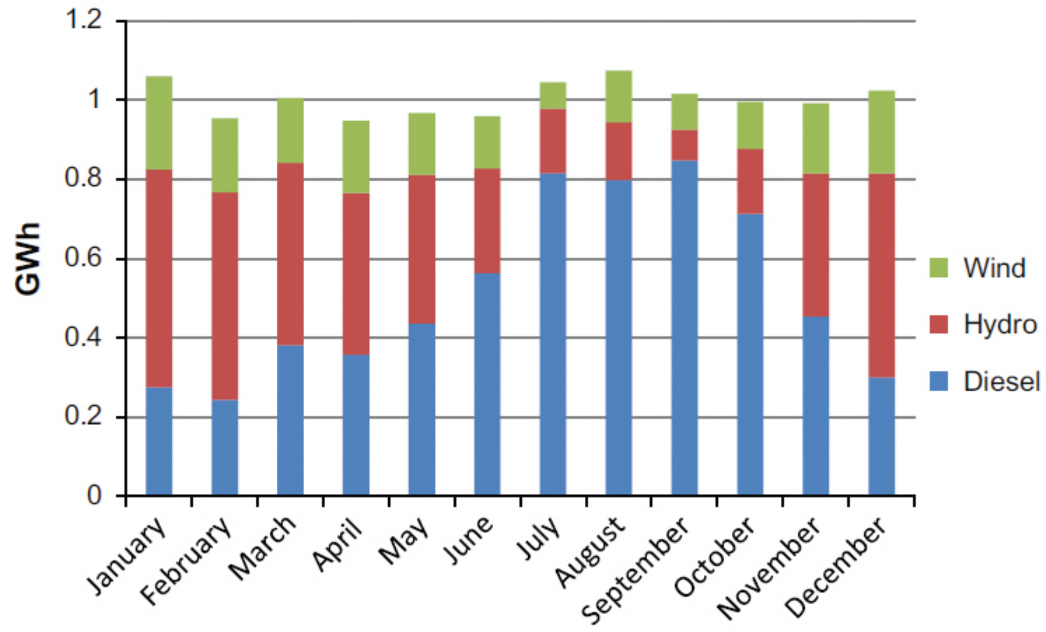


Figure 4.5
Monthly electricity production mix in Flores in 2010 [23]



4 Microgrid case studies

The production from renewable energy is however, highly seasonal with autumn and winter months achieving high shares of renewable energy (50 per cent–70 per cent) dropping to between 10 per cent–40 per cent during spring and summer as shown in figure 4.5.

After installation of the wind turbines in 2002, EDA found that they had to curtail the amount of wind power injected on the power system to avoid frequency fluctuations and blackouts. This was mainly as a result of the intermittency of the wind resource combined with the weakness of the power grid during low load conditions. A particular problem was the cascading tripping of the wind turbine generators during gusty wind conditions, or power line faults. The most critical operation period was the load valley when the low load led to a generation dispatch of a reduced number of hydro and diesel generation units.

On an isolated island power system, such as Flores, the ability to increase renewable generation is limited by amongst others the following [24]:

- Spinning reserve requirements. Spinning reserve is the amount of generation capacity that is immediately available, but not yet committed to the production of energy. Traditionally, on smaller power systems, this is usually provided by diesel or gas generators. Maintaining spinning reserve means that the generators are not operated close to their rate output power where fuel economy is usually the highest for base-load generators.
- Synchronous generator minimum loading. Diesel generators in particular experience unnecessary wear and tear when operated for extended periods below a certain percentage of their nominal rating. Typically, the minimum load requirement is 40 per cent. This means that the diesel generator should be run at a minimum loading of 40 per cent.
- Synchronous generator step load response. The step load capability of a generator is its ability to accept a sudden increase in load without the frequency dropping below a minimum value. This is usually determined by the dynamics of the generation system such as the response time of the primer mover's control system and the turbo lag of the diesel generator. For diesel generators the step load capability is typically 50 pr cent–75 per cent of the remaining capacity. For gas engines it can be as low as 10 per cent.
- Power system stability. Diesel generators have sufficient control bandwidth and inertia to ensure system stability during disturbances, but other sources have poor frequency control. Even through hydro generators have large amounts of inertia due to their synchronous nature, there is usually a significant delay between opening the penstock valve and the generator producing power.
- Renewable resources such as wind and solar (and some hydro generators) are typically configured to operate with a fixed power output (power set-point mode) to maximise the amount of energy produced from the primary source. As a result, they do not contribute to frequency control and therefore system stability. As the percentage of renewable energy sources increases on a grid the system stability decreases with increasing persistent frequency oscillations following disturbances.
- Reactive power and voltage control requirements. As renewable energy sources increase on the grid the remaining synchronous generators become increasingly responsible for reactive power management and voltage control of the entire system. High variability in wind (or solar) generation therefore contribute to poorer voltage regulation, increased flicker and generator overcurrent trips even at light loads.

4.1.3 Limits to renewable energy penetration

As a result of the intermittency of the wind resource, a certain minimum amount of spinning reserve needs to be available to cover events where the renewable energy falls away. The combination of spinning reserve requirements and the requirement for 40 per cent minimum loading of the diesel generators limits the amount of renewable energy penetration.

For the Flores system, the maximum renewable energy penetration was calculated to be 50 per cent [24] prior to the addition of any voltage control mechanisms such as SVCs, STATCOMs or storage systems.

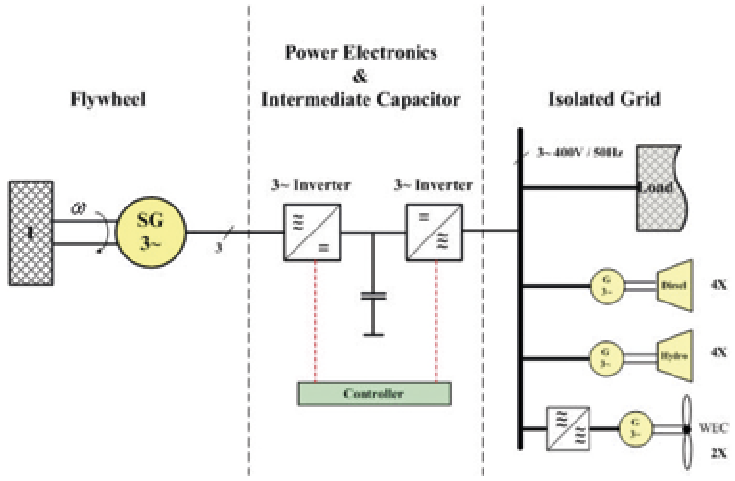
4.1.4 Improving system stability

Current operational practices in Flores recommend the use of at least one diesel generator to perform load following and frequency control. Although the hydro generators are also synchronous machines, the high penstock head height and conduit length result in a delay in generation starting time, which means that it cannot perform frequency control without the diesel generation. The mechanical wear and tear of the fast-governing actions also restrict the use of the hydro generators for primary frequency control.

The type of control used on the hydro and diesel generators in Flores limited the renewable energy penetration mainly due to power system stability issues. Load step response, spinning reserve and reactive power requirements were not the limiting factors.

To improve the stability of the Flores power system and to maximise the amount of power produced from wind and hydro, a flywheel energy storage system (FESS) was installed in 2005. The primary objective was to improve frequency and voltage stability and in doing so reduce the number of blackouts. A 350kW/5kWh FESS was connected on the 400V system bus as shown in figure 4.6.

Figure 4.6
Overview of the flywheel system connected the Flores grid [24]



A secondary objective of the FESS was to supply the entire island from renewable energy during light load conditions typically during the winter months.

The following characteristics of the FESS made it suitable for the particular application on Flores:

- high power density (the unit and power electronics fitted inside a 20-foot shipping container);
- short recharge time;
- state of charge is easily measurable (i.e. it is related to the rotational speed);
- charge and discharge have the same power rating;
- no capacity degradation over time (unlike batteries);
- long life time (unlike batteries); and
- operates equally well on shallow and deep discharges (unlike batteries).

The flywheel is configured for dynamic frequency support as well as dynamic voltage support. A frequency reduction in the system load resulting from a load change or reduction in renewable generation is countered by the flywheel supplying energy to the grid. During a frequency increase the power set point on the flywheel is made negative and the surplus energy is stored in the flywheel.

The dynamic voltage support operates in a similar way to the frequency support in that reactive power is fed into the grid when the measured system voltage is low, and absorbed from the grid when the measure voltage is too high.

The power system response to disturbances before the FESS is shown in figure 4.7. The 350kW step change in load is representative of a single wind turbine or hydro generator tripping. The system frequency displayed an underdamped frequency response with an oscillation frequency of approximately 3 Hz, a minimum frequency of 48.6 Hz and a maximum frequency of 50.4 Hz.

Figure 4.7
Measured power system response to a 350kW step increase in load with no FESS [24]

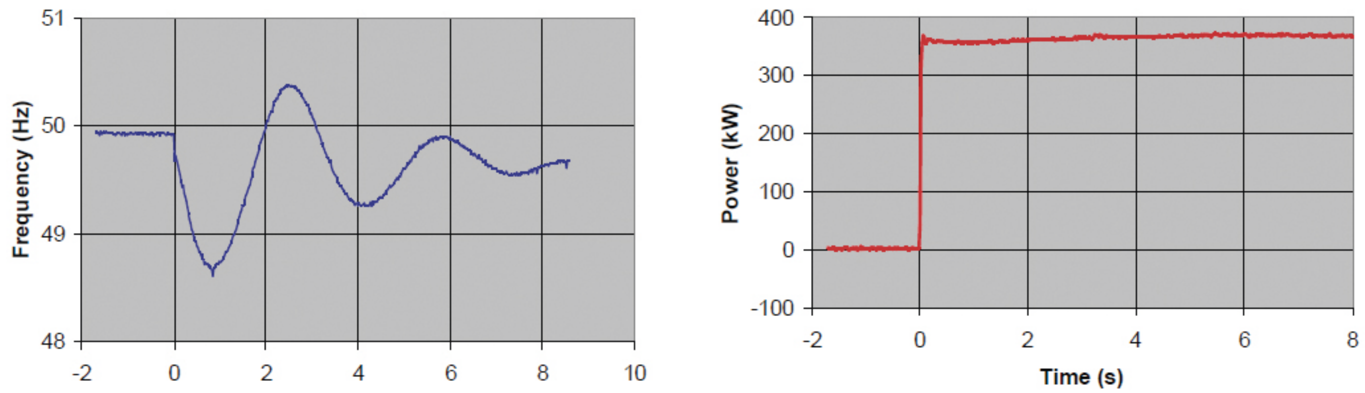


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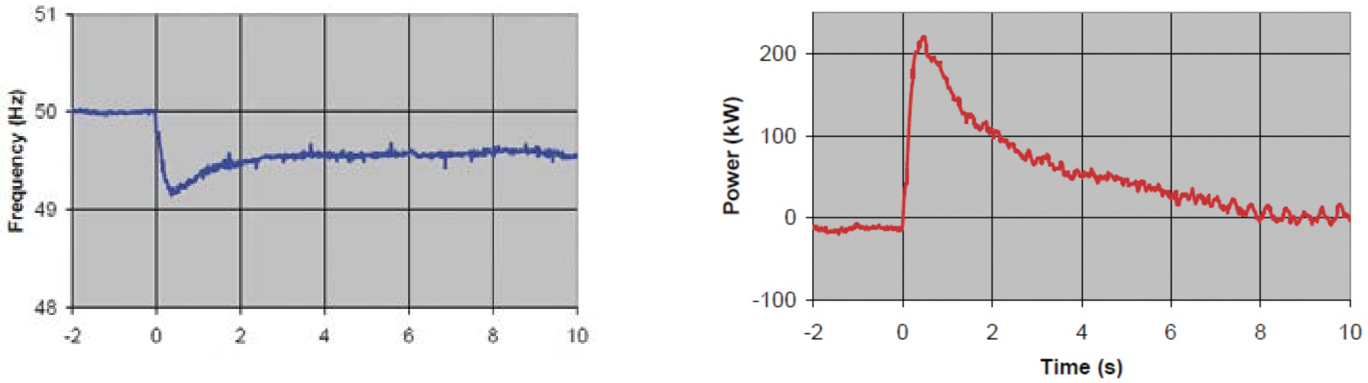
Figure 4.8

Measured power system response to a 350kW step increase in load with the FESS enabled [24]



The measured results with the same step load, but this time with the FESS connected is shown in figure 4.8. In this instance the frequency was found to be well damped with no oscillation and settled to the steady state after about 4 seconds. The minimum frequency was recorded as 49.2 Hz.

The measured results suggest that the FESS considerably improved the system stability by reducing system voltage and frequency fluctuations during normal operation (as well as during line faults). Since the FESS was introduced on the island the cascading of wind turbine trips ceased. The inclusion of the FESS also enabled the wind turbines to be operating without power restrictions i.e. at maximum power output. This resulted in the energy generated from wind potentially increasing by 33 per cent from 1,580 MWh to 2,100 MWh per year resulting in significant diesel fuel savings.

4.1.5 Leveraging Electric Vehicles (EVS) for further stability improvements

In keeping with the Government of Azores's objective to reduce diesel as a primary fuel source on the island, it adopted the electrification of transportation as a strategy. The introduction of Electric Vehicles (EVs) on the island presents both a risk and an opportunity for the operation of the power system. Several studies about the integration of EVs on the Flores grid have been undertaken [21], [23], with the conclusion that flexibility must be introduced in the EV charging process to mitigate possible load related problems.

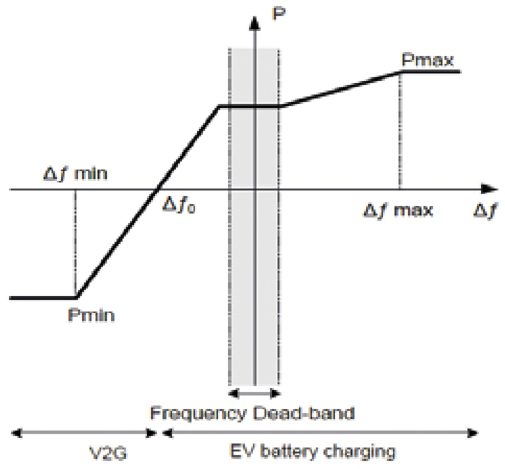
The introduction of a sophisticated, flexible EV charging structure is considered an enabler for further wind and solar integration as it could help to smooth large load/generation imbalances resulting from wind / solar resource fluctuations.

EV flexibility is considered particularly useful for primary frequency control on networks where highly variable renewable generation is available. The primary frequency control could be achieved by including a P-f droop control strategy in the EV coupling converter as shown in figure 23 that would enable the EV to actively adapt to the power exchanged with the grid based on the local frequency measurement. For frequencies around the nominal 50 Hz, the EV will charge the battery at a pre-defined charging rate.

If the system frequency drops below the dead-band minimum as a result of a disturbance or reduced wind generation, the EV will reduce its power consumption and loading on the system. For very large disturbances which result in the frequency dropping below the zero-crossing frequency (fo) the EVs will start to inject active power into the grid, operating in Vehicle-to-Grid (V2G) mode.

Figure 4.9

EV charger power-frequency droop characteristic [21]



The participation of EVs in regulating frequency on the island of Flores would be limited to a pre-defined frequency range. The grid operator would need to set the EV control parameters in order to coordinate the frequency control of EVs with other mechanisms such as load shedding, the flywheel energy storage system, other storage devices and their state of charge. The amount of power absorbed/injected for out of range frequencies would also need to be defined.

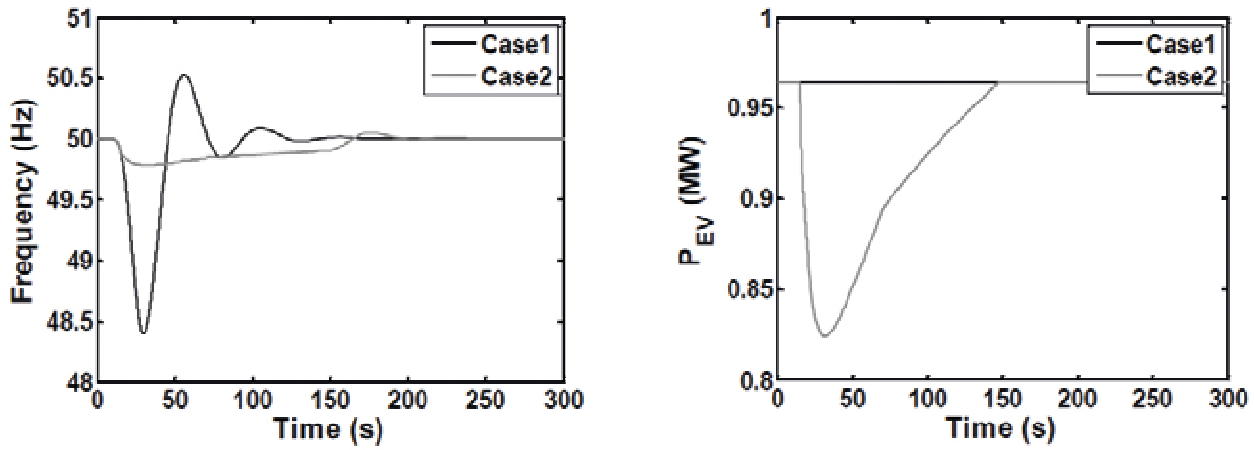
To illustrate the potential benefits of EVs in primary frequency regulation, a power valley scenario of conventional load of 730 kW was considered, with generation and frequency control only provided by the wind and hydro generators, i.e. no diesel generation. For the analysis, in [21] it was assumed that 25 per cent of the island's 2,000 vehicle population was replaced with EVs and all of them adhered to the smart charging scheme such that they would all concentrate their load on the valley periods. In such a scenario the EV charging load would be around 965kW. To accommodate the additional load an expansion scenario was assumed of three additional 315 kW wind turbines. Frequency regulation was assumed to be done only by the hydro power station. A wind gust was then simulated resulting in the wind generation dropping from 500kW–300kW. The simulation results are shown as Case 1 (no EV contribution) and Case 2 (EV primary frequency regulation) in figure 4.10.

Under a full renewable energy-based generation scenario, and without EV contribution to primary frequency control, the system frequency dropped to 48.4 Hz and oscillated for some minutes. When the EV frequency response was included the frequency was much more stable and did not fall below 49.8Hz. During this event the EV charging power temporarily changed from the original 965kW to 824kW resulting in a reduction of 3.6 per cent of the energy absorbed by the batteries during the 300s simulation.

The results confirm that EVs could be successfully used to limit frequency drops as well as frequency oscillations, thereby positively contributing to system stability.

Figure 4.10

Contribution of EVs to frequency regulation: Frequency and EV active power



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4.1.6 Learning points from Flores

The island of Flores generates 50 per cent of its energy from renewable energy sources, of which about half is supplied from intermittent wind. To maintain a stable system, at least one synchronous diesel generator is necessary at all times and it needs to operate at a minimum of 40 per cent load. The installation of a 315 kW FESS has helped to improve system voltage and frequency control and make it less susceptible to variations in the energy generated from renewable sources. It has also been determined that the introduction of EVs with smart charging could further improve the frequency stability of the network, leading to an increased penetration of renewable energy sources.

The following lessons can be learned from operating the power island on Flores:

- a synchronous generator is required for basic system stability and providing spinning reserve for system stability
- system stability can be improved by introducing energy storage systems such as FESS, batteries or EVs, which can provide a fast frequency response to arrest frequency drops and oscillations during network disturbances
- energy storage systems could potentially be used to replace the voltage and frequency stability functions provided by the synchronous diesel generator
- the particular wind turbine model used on the island was discontinued several years ago and no mention is made of the turbine controller's ability to be programmed for voltage and frequency support. If this was the case, then the turbines could have actively contributed to power system stability.

Figure 4.11

Location of St. Eustatius island

4.2 Island of St. Eustatius, Netherlands, Caribbean

(Reference [20])

4.2.1 Introduction and power system overview

The island of St. Eustatius is part of the Antilles in the Caribbean Sea. It has an area of 21km² and close to 4,000 inhabitants. It became a special municipality within the Netherlands in 2010.

The electrical grid consists of a 12.45 kV MV network with a peak demand of about 2 MW. Until 2016, electricity was entirely generated by the following diesel generators:

- Three x generators = 3, 350kW total capacity (automatic operation)
- Five x 350 kW = 1,750 kW total capacity (manual operation), resulting in a total diesel generating capacity of 5.1 MW.

4.2.2 Installation of Solar and Battery Storage System – Phase 1

In 2016 and 2017 the Dutch Government in collaboration with STUCO (Statia Utility Company) implemented a solar PV and storage system in two phases.

During Phase 1, a hybrid plant controller was installed and connected to the 8 diesel generators. The main functions of the plant controller included:

- monitoring the diesel generators;
- controlling PV ramp rate;
- energy shifting between batteries, solar system and diesel generators;
- maintaining dynamic diesel generator spinning reserve;
- maintaining minimum loading for the diesel generators;
- providing generator reverse power protection; and
- reactive power control for voltage stability.

The operation of the Phase 1 system over a 24-hour period including a sunny day with typical cloud movement is shown in figure 4.12.

The figure shows that the load demand varied between 1500 and 2200 kW during the day. During the day the solar power generation provides most of the power with the diesel generators operating at their minimum load level. The battery system covered the variation in solar power resulting from passing clouds. The PV system contributed 23 per cent to the island's energy requirements.

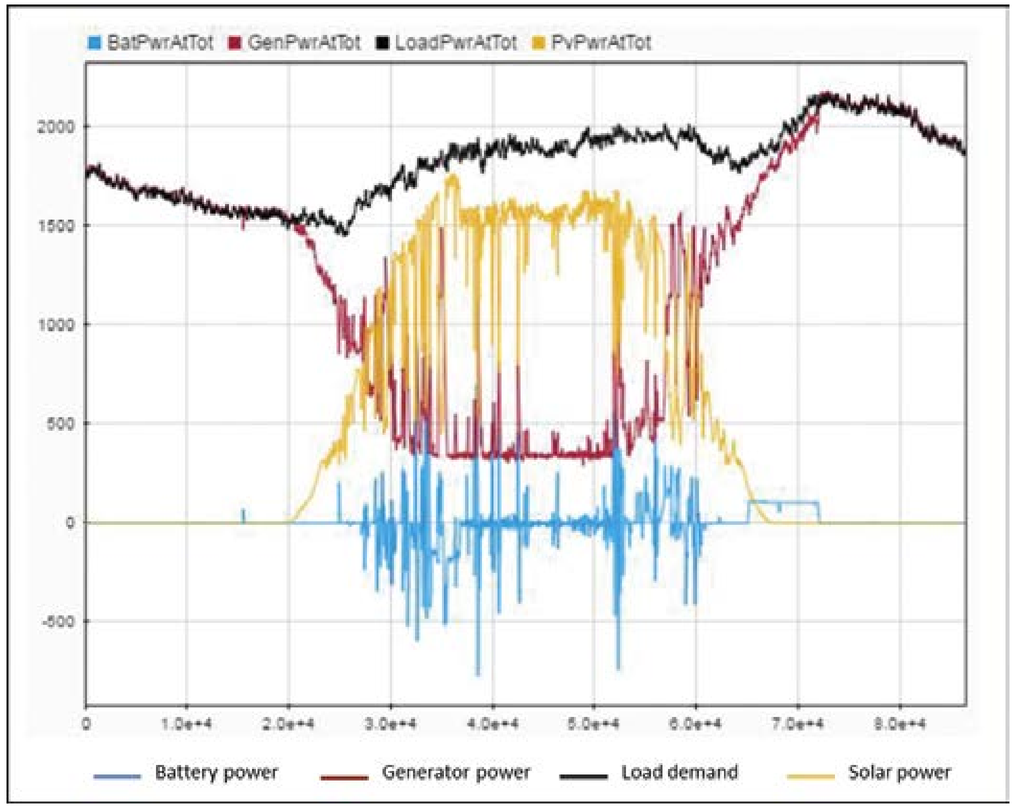
Table 4.2

Solar and battery storage installation

Project phase	Year commissioned	Solar system	Battery system	% generation share
Phase 1	2016	1.89 MWp, 1.8 MVA	1 x 1 MVA, 0.6 MWh	23%
Phase 2	2017	2.25 MWp, 2.0 MVA	2 x 2.2 MVA, 2.6 MWh	23%
	Total	4.14 MWp, 3.8 MVA	5.4 MVA, 5.8 MWh	46%

Figure 4.12

Phase 1 operation on a sunny day with typical cloud movement (June 2017) [20]



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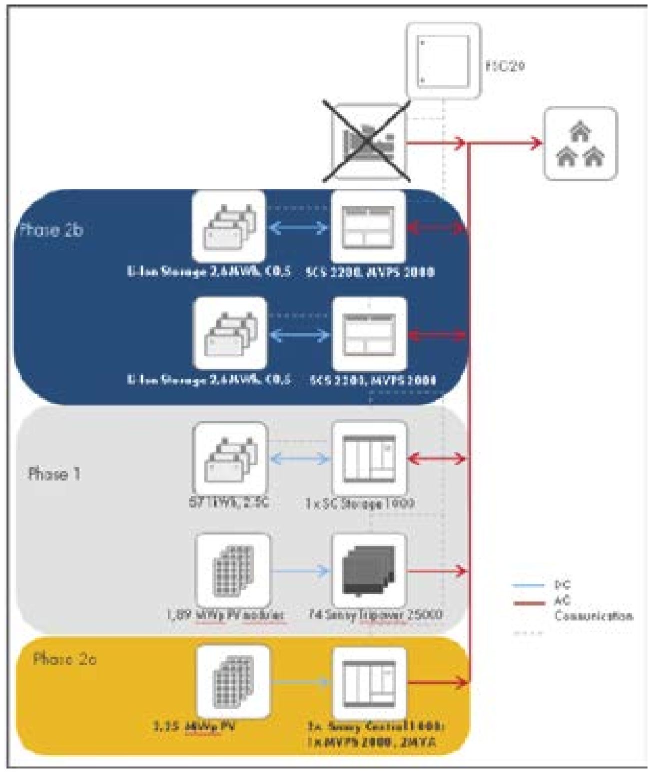
4.2.3 Enhancement of microgrid

Phase 2 of the project aimed to increase the energy contribution from solar to 46 per cent, but also the operational flexibility of the system to reduce the dependence on the diesel generators. Extension to the PV and battery system were added as shown in table 4.2 to increase capacity.

Figure 4.13

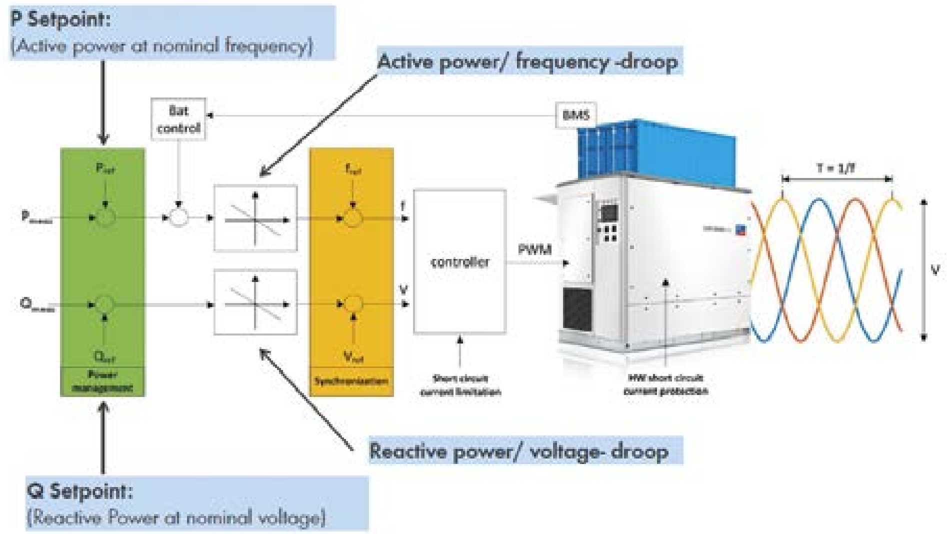
Setup of the Solar and Storage System after Stage 2 [20]



Two battery storage inverters were added with grid-forming capability. The mode of operation of the hybrid system was also changed to include grid voltage and frequency control and to include start/stop control over the diesel generators. The final setup of the system is shown in figure 4.13.

Figure 4.14

Overview of the grid forming inverter



The configuration of the grid-forming inverter is shown in figure 4.14.

The grid-forming control unit of the battery inverter was designed to perform the following grid management functions:

- allow parallel operation of the PV system with the diesel generators;
- same grid control mode with/without the diesel generators;
- automatic active/reactive load sharing between all generating units (without communications);
- adjustable load dispatching via the communication system to the grid-forming inverters;
- accept nominal power load steps within one cycle of the grid frequency; and
- supply fault current during short-circuit conditions both with/without the diesel generators in parallel.

The hybrid system controller was designed to performing the following services:

- automatic energy management by matching solar generation and demand;
- automatic control over the diesel generators in terms of start/stop commands;
- ensuring smooth power transitions when the diesel generators where switched on or off;
- perform secondary frequency and voltage control when the diesel generators are off; and
- immediate take-over of grid control in the event of a diesel generator failure.

Phase 2 of the St. Eustatius solar and battery storage system was commissioned in November 2017.

4.2.4 Resilience of the microgrid

The site acceptance test process of the system verified the resilience of the microgrid system for different failure scenarios. The following scenarios are of particular interest:

- provision of sufficient fault current in the event of a short circuit fault;
- resilience to loss of system communications; and
- power quality during disturbance events.

Provision of fault current during short-circuit faults

The following real faults were created on the St. Eustatius grid to verify that the system was able to provide sufficient fault current to trigger the protection devices on the network without the diesel generators being connected:

- single phase-to-ground;
- Two-phase short circuit; and
- Three-phase short circuit.

The voltage measurement results for the 3-phase short circuit fault with the diesel generators disconnected is shown figure 4.15. Short circuit current was provided by the battery and solar inverters only and successfully tripped the 30A MV fuses before the fault. Figure 4.15 shows that the fuses were tripped within 100ms, and that the system was able to recover the voltage within 20ms.

Resilience to loss of system communications

The solar-storage system is essentially a distributed system with redundant communication between the grid-controller, the diesel generators, battery systems, and solar inverters being essential for steady-state voltage and frequency control (Refer to figure 4.13 for an overview of the communication system.) A test was performed in which communications was disrupted while the solar system was generating without the diesel generators.

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Without communications the hybrid controller disabled its secondary frequency control function which resulted in some higher frequency fluctuations from the 60 Hz nominal frequency (max 60.1 Hz, min 59.6 Hz). However, it maintained its demand/supply balance function, and automatically started and synchronised the diesel generators. When communications were restored, the controller automatically switched off the diesel generators and resumed normal operating mode.

Resilience to synchronous generator failing

A test was performed to determine the response of the system to the loss of all diesel generation during the night. At the time of the test, two diesel generators supplied a load of 2 MW. Both generators were disconnected at the same time. The active power and frequency response of the system is shown in figure 4.16, together with the set points of the inverters.

The system responded to the disturbance in the following way: the grid-forming inverters took over the load immediately and shared the load equally between them. After about 500ms the hybrid plant controller detected that the diesel generators were off, and modified the battery inverter's active power set points to enable secondary frequency control response. The frequency was restored back at 60Hz within 2.5 seconds after the generators were disconnected. During this time the frequency dipped to 59.38Hz, which aligned with the inverter's droop settings of -1.8Hz/Pnom.

Figure 4.15

Voltages (L-N) during the 3-phase short circuit fault

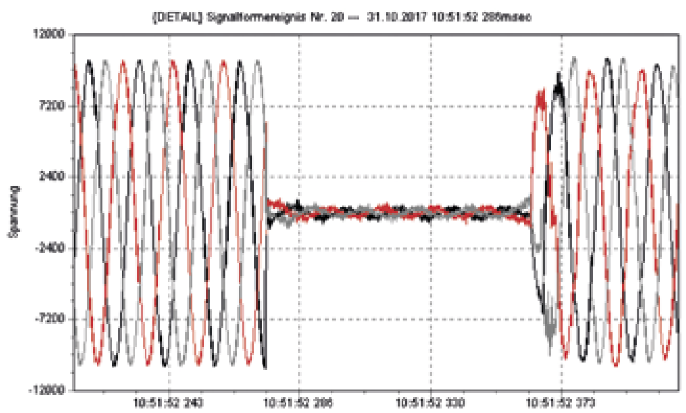
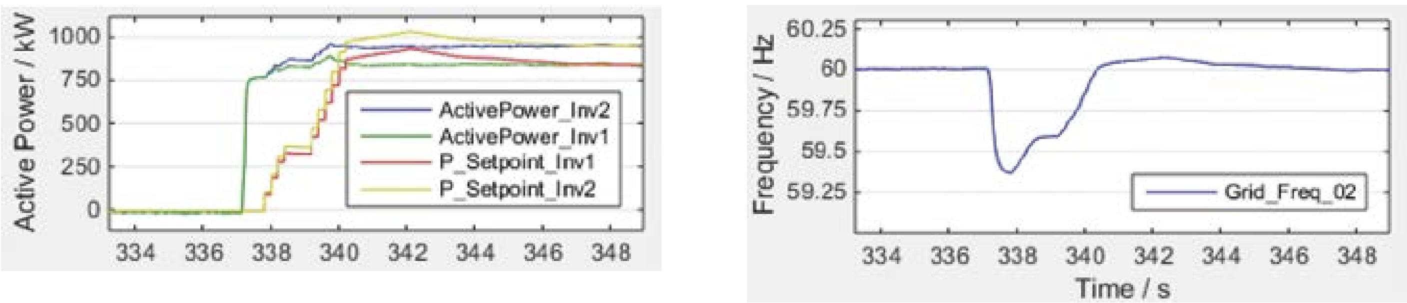


Figure 4.16

Active power and system frequency response to generator failure, with inverter set points



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4.2.5 Power Quality Management and Operation

Measurements taken during the first 9 months of the system's operation verified that the system was able to maintain a stable voltage and frequency during levels of solar intermittency without the support from the diesel generators.

During a 1-hour measurement test in October 2017, there were solar power variations between 2.8 MW and 0.5 MW with ramps of > 1MW/20s. During this time:

- Grid frequency varied by no more than 13mHz;
- The phase-to-phase voltages remained between 99.36 per cent and 99.84 per cent of nominal voltage; and
- Total harmonic distortion remained in the range between 0.8 per cent and 1.3 per cent for all three phases.

Figure 4.17 shows a 24-hour overview of the power outputs on a typical day. This shows some improvement from those in Phase 1 (figure 4.12). In the morning, the solar system is first used to reduce the power coming from the diesel generators. Once the generators reach their minimum load level, the batteries are charged until the generators can be switched off. In the evening, the power from the batteries is gradually increased, and once depleted the generators are switched on again to provide power during the night.

The solar energy share increased to between 46 per cent–54 per cent on a daily basis. An average of 10 hours of diesel off time was achieved per day. Even though several generator failures occurred during this time, the voltage-controlled battery inverters were able to maintain grid stability.

Black-starting the St. Eustatius grid using only non-synchronous generation has been identified as the next stage of development and testing for this microgrid.

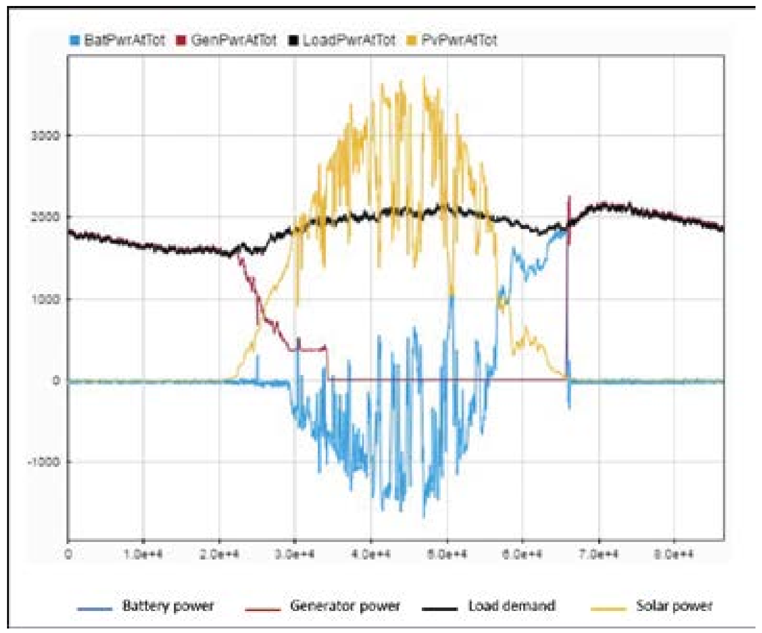
4.2.6 Lessons learned from St. Eustatius

The following lessons can be learned from the St. Eustatius island project:

- 100 per cent inverter-based grids can be operated at Megawatt-scale
- grid forming or voltage-control-mode inverters can be used successfully to establish and maintain the voltage and frequency on a microgrid without the support of synchronous machines
- the inverters can successfully perform automatic load sharing and accept load steps of nominal power
- the inverters can provide sufficient high current during faults to trigger the protection devices on the MV system
- microgrid controllers can dynamically control all the generation and demand on the system
- microgrid systems with battery storage systems can maintain stable voltage and frequency even when losing all generation
- microgrids can be designed to be resilient against communications and other plant failures.

Figure 4.17

Phase 2 operation on a sunny day with typical cloud movement (June 2018) [20]



4 Microgrid case studies

4.3 Portability towards a distribution grid

Most grid codes currently inhibit the implementation of grid-forming inverter capability at DER facilities. However, DER grid-forming capability can contribute to system stability in a grid with high shares of renewable energy. The same grid-forming inverter used in the St. Eustatius project could be operated in parallel with a distribution grid and assist with voltage and frequency stabilisation to meet the latest requirements of ENTSO-E for the connection of generators [31].

Current-controlled inverters can provide primary frequency response, but their ability to control system stability is limited on networks with high-impedance levels due to long lines or high levels of DER. On these networks however, voltage-controlled inverters can function as a reliable voltage source as well as having some other benefits. The current and power flow to the grid depends on the transient difference between the voltage vector of the inverter, the deviating vector of the grid's voltage and the coupling impedances. If the grid's voltage changes suddenly in amplitude, phase or frequency, the inverter injects a stabilising current causing an "inertial" behaviour and advantageous high current from inverters connected to the grid. [20]

To control the current flow and keep it within a stable operating region, the inverter voltage needs to remain synchronised with the grid voltage and the current needs to be limited. This behaviour needs to be specified in the relevant grid code.

Current grid codes for inverter-connected generators specify current infeed behaviour that is based on a simple model of a synchronous machine in a way that can be fulfilled by current-controlled inverters. Applying the same requirements to voltage-controlled inverters neglects the inherently positive behaviour of these inverters with respect to maintaining grid stability in the event of a fault. The grid-forming capability of voltage-controlled inverters is generally not required for inverter connected DER. Traditionally inverter-connected DER are configured to provide maximum power and in normal operation don't provide headroom for supplying additional active power for grid stability. However, battery systems could provide this as an additional service to the grid.

DERs with voltage-controlled inverters at MV and HV levels could help to effectively stabilise a power grid with renewable energy sources in the event of faults, system splits or load steps. Battery-equipped DERs could replace the must-run synchronous units in the grid to allow for 100 per cent inverter-based grid operation, while voltage control mode inverters could improve the operating ability of power islands and could play a role in grid restoration. Diesel or gas synchronous generators would only be required in emergency situations when insufficient renewable energy is available.

5 Conclusions

Microgrids are finding increasing application on LV and MV networks, and in most cases tend to have a high share of renewable energy sources. This report focused specifically on non-isolated MV microgrids that could operate in an island mode during an outage on the main power grid.

5.1 Microgrid specifications

From the literature review, as well as the case studies, it is clear that microgrids need to be well planned and designed. Their boundaries need to be determined upfront based on expected generation and demand, flexibility of load and energy storage capacity. Each microgrid should have a dedicated microgrid controller and communication system to monitor and take control of all the DER generation, energy storage systems and controllable load during island mode and communicate the status and expected duration to the DSO. The microgrid controller is responsible for facilitating disconnection from the grid, operation of the island, and reconnection to the grid under control from the DSO once voltage and frequency on the distribution grid has been restored.

5.2 Main operational challenges

The main challenges likely to be experienced by microgrids in island mode include:

- voltage stability;
- frequency stability;
- convertor stability;
- protection reliability of operation;
- fault ride-through stability; and
- electrical safety due to earthing.

5.3 Strategies to overcome challenges

The operational challenges can be addressed though inertial responses provided by synchronous compensators, wind turbine controllers operating as virtual synchronous machines, or BESS. BESS appear to offer the most flexibility and is also likely to be the most cost effective.

Convertors can be tuned/programmed to overcome potential PLL instability as a result of the low SCL. It is important that system planners and operators utilise manufacturer specific PLL models in their simulations rather than generic PLL models to study the performance of microgrid in order to gain an accurate result.

Frequency stability in the microgrid can be improved by utilising wind turbines and/or BESS for frequency control. DSR could also be used to provide frequency support by disconnecting controllable load.

Protection reliability issues could be addressed in a number of ways. This includes programming the convertor controllers to provide negative sequence fault current, adjusting protection relay settings, or considering alternative protection schemes that are less sensitive to small differences between the load and fault levels.

Dedicated earthing should be provided to all microgrids to ensure the safety of plant and people.

5.4 Learning points from case studies

The two case studies produced several learning points, with the following being the most significant:

- 100 per cent inverter-based grids can be operated at Megawatt-scale
- grid forming or voltage-control-mode inverters, used in conjunction with BESS can be used successfully to establish and maintain the voltage and frequency on a microgrid without the support of synchronous machines
- system frequency stability can be improved by introducing energy storage systems which can provide a fast frequency response to arrest frequency drops and oscillations during network disturbances
- Inverters can provide sufficiently high current during faults to trigger the protection devices on the MV system
- microgrid controllers can dynamically control all the generation and demand in a microgrid system.

Currently, converter-connected generation such as wind and solar operate in a maximum power output mode. There are currently no incentives for them to operate in a voltage or low frequency control mode. The GB Grid code [42] would need to make provision for these alternative control modes, and/or special commercial arrangements would need to be made between the DSO and the microgrid owner if the microgrid is required to operate as an island during a partial or total shutdown event.

Technically there is no reason why microgrids with a high share of convertor connected resources could not be operated reliably. Microgrids/power islands therefore have sufficient strength and stability to play an important role in supporting Black Start of the distribution and transmission power grid as envisaged in the National Grid ESO System Operability Framework [1].

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Abbreviations

Acronym	Description	Acronym	Description
ANM	Active network management	PLL	Phase locked loop
BESS	Battery energy storage system	POC	Point of connection
DER	Distributed energy resources	p.u.	Per unit
DNO	Distribution network operator	PV	Photo voltaic
DSO	Distribution system operator	Q	Reactive power
DSR	Demand side response	ROCOF	Rate of change of frequency
WTG	Wind turbine generator	SCADA	Supervisory control and data acquisition system
EREC	Ena engineering recommendation	SCL	Short circuit level
ESO	Electricity system operator	SOF	System operability framework
EV	Electric vehicle	SGU	Significant grid user
FESS	Flywheel energy storage system	SVC	Static var compensator
kV	Kilovolt	TNO	Transmission network owner
LFDD	Low frequency demand disconnection	TRL	Technology readiness level
LV	Low voltage	TSO	Transmission system operator
MV	Medium voltage	V2G	Vehicle-2-grid
MW	Megawatt	VPP	Virtual power plant
NG	National Grid	VSC	Voltage source converter
P	Active power	VSM	Virtual synchronous machine
PCC	Point of common coupling	WTG	Wind turbine generator

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