DSO ENTITY
DSOs FOR EUROPE

Grid Forming Roadmaps

Considerations for DSOs’ Risk-Assessment Input to National Roadmaps for adapting Distribution Systems to high penetrations of Grid Forming Power Park Modules

Based on the ACER draft NC RfG 2.0 published December 2023

28 July 2025

Glossary of Terms and Acronyms

Term/Acronym	Meaning
ADMS	Advanced Distribution Management System
CB	Circuit Breaker
DSO	Distribution System Operator
EU	European Union
EV	Electric Vehicle
FSM	Frequency Sensitive Mode
GFC	Grid Forming
HV	High Voltage
IGD	Implementation Guidance Document (defined in RfG 2.0)
LFDD	Low Frequency Demand Disconnection
LFSM-O	Limited Frequency Sensitive Mode - Overfrequency
LV	Low Voltage
MS	Member State
MV	Medium Voltage
NC	Network Code
NMS	Network Management System
NRA	National Regulating Authority
OH	Overhead
PGM	Power Generating Module
PPM	Power Park Module
RfG	Requirements for Generators
RoCoF	Rate of Change of Frequency
SCADA	Supervisory Control and Data Acquisition
TSO	Transmission System Operator
UG	Underground
V2G	Vehicle to Grid

Table 1 - list of definition and acronyms

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Executive summary

This document has been written by the EU DSO Entity's Expert Group on Existing Network Codes, with the aim of assisting DSOs assess the risks and issues associated with the necessary accommodation of grid forming power park modules (GFC PPM) within distribution systems. It is not intended to highlight the merits or demerits of GFC, but rather to support the decision process of implementing GFC at the national level.

The proposed update of the network code Requirements for Generators (NC RfG) is expected to enter into force in 2025, or on early 2026. Within three years of entry into force, all larger power park modules (PPM) will need to be grid forming (as opposed to grid following) in order to ensure the ongoing integrity and stability of European electricity systems. Smaller PPMs might also need to be GFC, but this will be subject to a national implementation road map.

The roadmap is necessary to provide the time for DSOs to make any necessary adaptions or modifications to the DSOs systems or to their operational practices such that the growth of GFC PPMs does not present risks to public safety and to the continuity and quality of supply.

The advice in this support document is aimed at helping DSOs identify the risks that arise from GFC PPMs, and their mitigations. The risks are currently thought to be mainly associated with GFC PPMs' capabilities to maintain unintended and unmanaged power islands within DSOs' networks (as opposed to intended and managed islands), but there are also possible risks relating to distribution network stability and to continuity of supply indexes. The aim is, to the extent possible, to establish a uniform approach to methodology that can be adopted across all DSOs. That said, DSOs are totally free to adopt their own ethos, policies and practices into the quantification of the risks discussed.

DSOs will need to identify the risks for their networks, and decide what the efficient mitigations are, as their input into the creation of the national roadmaps for GFC PPMs. Indeed, in some instances, such as embedded MV and/or LV connections, it may be agreed amongst the parties, that the cost of mitigations may be so prohibitive or impractical to implement, that GFC will not be mandated.

The EU DSO Entity believes that the draft NC RfG should require that road maps will be created for regulatory approval within two years from entry into force. In line with the DSO Entity's strategic Technical Vision, grid-forming technology will be essential in ensuring grid stability and operational control at the distribution level.

This advice is written for DSOs, however it is believed to be equally applicable to CDSOs and to the networks of large industrial installations, where compliance with the GFC requirements of the NC RfG is also required.

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Introduction and background

The advice in this support document has been written by the EU DSO Entity as a guide for DSOs and NRAs in assessing the technical considerations that will be necessary when implementing the GFC requirements of the new network code Requirements for Generators 2.0 (NC RfG 2.0), which is presently expected to enter into force sometime during 2025 or early 2026.

In Figure 1 below, which depicts the EU DSO Entity's high-level assumption of how the NC RfG 2.0 road map requirements of Article Y.5 will be implemented, this support document is intended to assist DSOs in undertaking the risk assessment which the EU DSO Entity is proposing is an essential part of roadmap creation, ie the green box in Figure 1. The EU DSO Entity's view of what the road map itself should contain is attached as Appendix B.

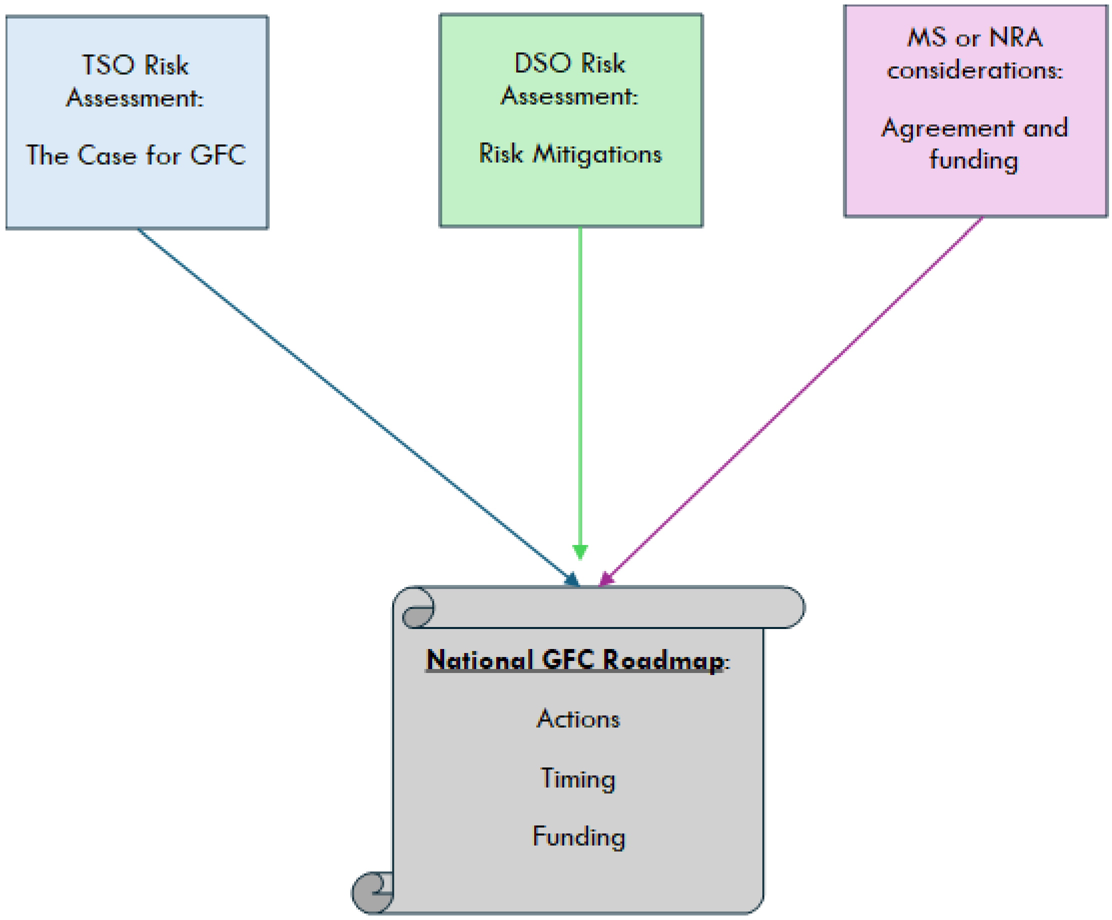

Figure 1 – Assumed roadmap creation process

The key focus of this support document is the several risks associated with the introduction of GFC power park modules (GFC PPM) or GFC EV3 V2G electric vehicles into distribution systems. These risks are a product of the necessary introduction of GFC PPMs into the European power systems and of GFCs' essential contribution to overall system stability and integrity. But these desirable and necessary features at the overall power system level also increase the likelihood of unintended and unmanaged power islands being formed within distribution systems. These are relatively well conceptually understood. The historic incidence is very low due to measures that have been put in place to prevent them, but the future incidence is one of the key risk factors to be evaluated.

By contrast, intended and managed islands are not considered an issue for the secure and stable management of (public) grids as they have been designed and are being managed to ensure safety as well

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as avoiding unnecessary and avoidable damages to installations. Thus, for example, closed distribution systems, industrial grid users, or designated sections of distribution network that have been explicitly engineered for island operation, are out of scope of this document.

There are other risks, less well understood and even less well observed in history, associated with GFC technology such as the stability of GFC PPMs[1] when interacting with other plant and equipment in a DSO network environment. As these are less well covered at this point in time DSOs will need to be aware of future developments in understanding the risks and mitigations.

The aim is that, to the extent possible, a uniform approach to methodology is adopted across DSOs. That said DSOs are, of course, totally free to adopt their individual ethos, policies and practices into the quantification of the risks discussed. This support document is composed of two main parts: Part 1 is advice on the establishment of the likelihood of a power island sustaining for any longer than a very few cycles (ie a few tens of millisecond) and Part 2 is advice on the mitigations which might be needed or taken to keep the overall risk from islanding at or below the tolerable level.

Target Audience

There are two broad categories of target audience for this document. The document endeavours to speak to both depending on the context.

The first are those charged with the management and progression of a roadmap. The more general and process related content will be of relevance to this cohort.

The second are the technical and protection experts who will find themselves making judgements on the technical merits of the assessments and the feasible mitigations. There are large sections of this document that are necessarily very technical in nature which will be relevant and speak to this second cohort.

Scope

This work addresses all GFC generation that may be connected to DSOs' distribution systems. It encompasses the range of typical public distribution systems in the EU, as the EU DSO Entity understands them. It is designed to be comprehensive and applicable to any public distribution system in Europe, with the appropriate selection of characteristics within the document. As such it is also expected to be applicable to closed DSO systems, and to the networks of large industrial users, where the NC RfG also necessarily applies, although these are not the focus of the document. Both closed distribution systems, and particularly large industrial systems, can have existing large penetrations of synchronous machines, and so are already facing, and will have designed for, the risks identified in this document. But for those networks without significant historic synchronous generation, the risks and mitigations outlined in this document are expected to be useful should such networks have GFC generation introduced into them in the future.

Status of this support document

This advice has been written based on the current knowledge of the relevant experts within the EU DSO Entity at the time of writing. As noted above, GFC technology is still nascent, and DSOs' consideration of the risks and issues associated with accommodating GFC technologies within DSOs' networks will need to be continually updated. As knowledge of GFC technology, and its interaction with distribution systems,

[1] And also V2G EVs

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improves it is likely that the features of GFC can be harnessed by DSOs as useful resources for distribution system management.

Many strands of research are planned in the areas discussed, such as but not limited to, inter PPM oscillations, small signal stability, new and enhanced methods of island detection. This document will need to take any outcomes from such research, analysis, study and so on, into account, up to the publication of the roadmaps. Further, the roadmaps themselves will thereafter, necessarily need evolve and adapt to take account of such outcomes.

There are plans for an ENTSO-E IGD on GFC converters targeted at manufacturers, and there is work underway on a technical report (at the time of writing of this support document) to feed into that IGD. This support document might need to be updated in the light of the technical report, or subsequently the IGD.

The EU DSO Entity is aware of recent studies into aspects of GFC. Historically much research has taken place into island detection and management of islands, but not so much into stability issues. A good example of recent research is that undertaken by RWTH Aachen University[2] which focussed on the viability of existing and conceptual methods of detecting islands. This research confirms the significant concerns of this support document, namely that the increasing penetration of GFC converters will increase the risk of unintended islanding and make detecting islands more challenging as the penetration of GFC converters grows. The research concludes that new techniques for island detection are required, so it is crucial to continue with study and investigation, not only for an understanding increase but also for a better definition of solutions.

Where such outcomes are relevant and sufficiently material to drive a major revision to existing published the document, the EU DSO Entity shall endeavour to do so as quickly as practicable. It is not possible at this point in time to specify the frequency or timings of such revisions. However, where they arise, they will be socialized through the membership of the European Stakeholder Committee – Grid Connection.

Methods of island detection

Given the clearest risk is that of unwanted/unmanaged islands it is worth understanding the abilities of DSOs to detect islands. Managing an island once detected is an important consideration, but that pre-supposes that the island can actually be detected.

DSOs have insisted that generation connected to their systems is equipped with anti-islanding detection systems. In some cases, the generation owner must install the equipment, whereas in other jurisdictions it is the DSO that supplies the equipment.

There are three main types of island detection strategies: passive detectors, active methods and those that depend on communication, as well as combinations of these methods.

[2] https://publications.rwth-aachen.de/record/985500

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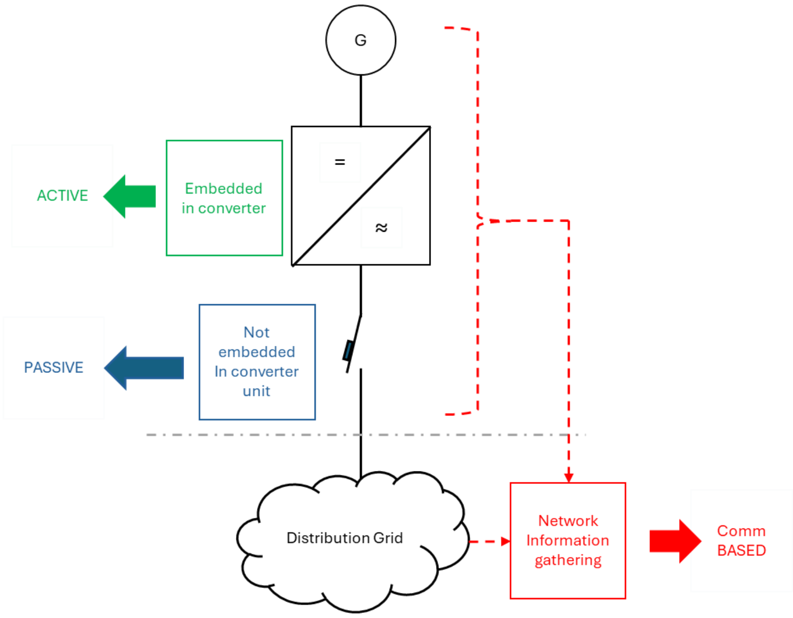

Figure 2 – schematic of three different classes of islanding detection techniques

Passive detectors

All passive detection methods work by observing the local voltage waveform. The simplest forms are just measurements of frequency and voltage, and when either of these move outside the prescribed upper or lower limit, it is assumed that this is likely because of an island formation. Although effective in many cases of potential islanding with existing grid following inverters, it is likely to be far less so where the control reaction of GFC generation will able be to maintain voltage and frequency within the prescribed limits. In such cases these techniques become ineffective.

Two more sophisticated approaches are RoCoF and vector shift. RoCoF, which is an abbreviation for rate of change of frequency, observes the rate of change of frequency on the system, and on the presumption that in the absence of an island, the grid frequency can only change slowly, a rate of change above a given threshold will indicate that the local network has become part of an island and its frequency is no longer tied to the grid frequency. To establish the rate of change threshold, it is usually necessary to observe signals over several cycles, and to filter out waveform distortions which could affect the accuracy of the measurements. Furthermore, there are no standards for the algorithms and filter methods.

Vector shift or vector jump works by assessing if there has been a sudden temporal shift in the voltage waveform. The switching of any reactive load will have this effect, but it is generally small compared to that which is expected to occur at the formation of an island. Vector jump can also occur during faults that don't lead to island formation. As with RoCoF there are no standards for what vector shift actually is, nor how it is measured, giving rise to further uncertainty over this protection method's performance in any specific implementation.

Both these techniques have drawbacks which may make them unsuitable in future. The changes in the mix of generation and demand overall on the system means that for some emergency events, such as a split of the central European transmission system, the rate of change of frequency which generation needs to withstand is greater than in the past. The draft NC RfG 2.0 has new RoCoF withstand requirements of 2Hzs-^{1} or even 4Hzs^{-1} for generation. Either of these values is beyond where RoCoF is effective as a method of detecting islands, where a setting of 1Hzs^{-1} is believed by DSOs to be the maximum that is effective; ie settings above this do not detect islands. Therefore the underlying assumption on which RoCoF protection is based, that the synchronous system rate of change of frequency is much smaller than when in a distribution island, may not hold in the future.

Similarly it is now realised that faults, and even switching operations (ie normal system operation like maintenance, load operation, energization of different types of assets etc), on the transmission system often give rise to phase shifts (ie vector jump) of more than the standard settings of vector shift devices – ie such devices are susceptible to maloperation due to normal transmission switching operations and faults. This is now an incompatibility with the NC RfG 1.0 requirement for generation to ride through transmission faults, and had been banned as an anti islanding protection in some countries.

Hence the likelihood of these passive methods being capable of detecting islands in future is questionable at best, and DSOs are unlikely to be able to rely on them for new GFC generation.

Active Methods

These methods rely on the generation equipment itself trying to operate in a way that is not possible when connected to the grid, but which are possible when islanded. The techniques broadly divide between the generation trying to change the system frequency (ie not possible when connected to the grid), or the generation trying to operate at an unnatural power factor which is only possible when connected to the grid. The latter reactive power/power factor set of techniques is not believed to be widely used, but the frequency shift technique is believed to be built into the majority of grid following solar PV inverters manufactured and sold worldwide.

There is no standard for these active methods, but there is a standard for assessing the effectiveness of any implementation – EN 62116. Some DSOs insist on PPMs[3] meeting the 62116 standard, whereas other DSOs do not recognize it as a valid test approach and do not accept active methods of detection. All these methods rely either on detecting a low short-circuit power in the grid or in their relative importance for the load/generation balance. However, there is the possibility that islands may form with some characteristics such that active detection methods are ineffective. There is also the unquantified risk that the non-standardised different active methods may influence each other, resulting in instability and/or ineffective protection performance.

It is also not clear at the time of writing this advice whether such active methods are compatible with GFC technologies. For example, frequency shifting techniques may be incompatible with the frequency support requirements for GFC inverters.

Methods involving communication

A number of other theoretical or developing methods do exist. Historically research has been undertaken into the identification of an island by phase comparison using satellites communications or other high precision sources of timings. It is not thought that there are any commercial implementations of these techniques.

Another developing method is for the monitoring of switching points and network voltage using DSOs' supervisory control systems. In this approach, the DSO's supervisory system (aka SCADA, ADMS, NMS or similar) monitors the key switches where islanding is expected to be possible and also monitors the system voltage downstream of the switch. If the switch is open (and all other relevant switches to the downstream network are open) and if there is system voltage present, that part of the network must be a power island. Historically DSOs' supervisory systems were not conceived with this application in mind and, therefore, inadequate for any kind of role like this. However, the increasing digitalization of DSOs' businesses means that this technique is viable for HV and most MV networks, subject to the installation of both the necessary additional system monitoring devices, including voltage and frequency measurements, and the

[3] And V2G EVs.

sophistication of the DSO's system management software. Other techniques, such as frequency comparison between several points of the grid, or a central reference point, may be also employed.

As a concept, use of a signal conveyed over power line carrier (PLC) has some attractive properties. Disruption of the PLC healthy status, as seen at the generator site, would be a good, in not completely foolproof indicator of the occurrence of an island. However, availability of a relatively inexpensive and reliable PLC implementation that was designed for MV or LV, would be a prerequisite, for this option to be even considered.

Time criticality of island detection

Where an island has given rise to an unsafe condition, it is clearly important to remove the hazard as quickly as is reasonably possible. In this context, as fast as reasonably possible is often taken practically to be a few seconds, say less than 5s. However, where a DSO has employed fast acting protection and auto-switching arrangements to minimise short duration interruptions to customers, the detection and tripping time for the generation supporting the island needs to be sub 1s. This is a challenging timescale for some anti-islanding protection; for example the default operating time requirement of EN2116 is 2s, which is incompatible with some DSOs auto switching schemes.

Inverters which do and do not possess all GFM functionality.

Manufacturers may develop power electronic converters which may deactivate their GFC capabilities or reduce them such as to behave as conventional converters (ie behaviour close to that of a current source as opposed to a voltage source behind an impedance). It is possible that some customers and/or some RSOs may request that manufacturers provide converters with these capabilities.

As part of the progressive introduction of GFM converters defined in the national road maps required by NC RfG 2.0, some RSOs may determine that it will be helpful to be able to change the operation of the converters in some power generating facilities, as described above at some future point, at some future point. The facility to deactivate the grid forming functionality may also be useful for provisional connections, the management and control of unwanted power islands, and where an otherwise GFC converter has to be connected to a LV network (for example in member states where Type B PPMs are connected at LV).

Where manufacturers do provide such capabilities, the deactivation of GFM functionality and vice versa may be effected by a simple toggle to modify the converter behaviour, or the manufacturer may provide the provision for various control parameters to be varied such that the converter behaviour changes.

The ability to effect the behaviour change described here may be only be possible at the power generating facility by the setting of specific parameters during the commissioning of the converter, or may be activated remotely while the converter is running. In this latter situation the elapsed time for deactivation of GFM capabilities and vice versa will need to be stated by the manufacturer so as to allow the RSO to include any implications in the connection agreement and in the RSO's operational rules.

Where GFM deactivation capability exists in a single converter or generating unit, it will be necessary that full compliance with the NC RfG 2.0 requirements is demonstrated for both operating modes.

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Part 1: Risk Analysis of the formation and maintaining of islands

General

This section gives a range of examples of a methodology to quantify, in a relative fashion, the risk of islands being formed in various categories of distribution network. This is further broken down into various scenarios. It is expected that the categories will cover the full spectrum of distribution networks and that those applying this section to their own roadmap, should be able to find categories to match those on their system and select them accordingly.

Initial high-level screening and baselining

DSOs will need to review the risks suggested by this advice and analyse the extent of how the risks are manifest in their own networks. In turn the analysis will need to inform if mitigations are necessary, and what those mitigations might be. It will then be necessary to consider how the mitigations will be deployed and what are all the other implications of doing so.

Assessment of future high penetration scenario using Network Development Plans

The volume of mitigations necessary will largely be driven by the anticipated growth of GFC PPMs in the DSO's network. From the draft NC RfG 2.0 it is assumed that most or all "directly connected"[4] GFC PPMs of type B and larger will be GFC from 3 years after entry into force of the NC RfG 2.0. The application of GFC to PPMs of type B and C which are not "directly connected" will depend on the national road map, although subject to the timescales in the road map, all such PPMs shall be GFC by the termination of the road map's timeline unless otherwise agreed as part of the roadma**p.**

It is noted that "directly connected" Type B, C and D PPMs tend to be connected at higher distribution voltages and therefore that these connections tend to have more real-time visibility and monitoring. This significantly reduces, though not eliminates, many of the risks described in this document and renders them more amenable to the types of solution described in row 8 in Table 5 below.

It is further noted that how the relative volumes of Type A GFC PPMs in particular, evolve post entry into force, will be informed by many variable factors such as;

- The extent to which TSO require GFC capabilities in Type A PPMs.
- The extent to which GFC capabilities may become attractive to customers in the context of resilience and self-supply, ie to cater for network outages etc.
- The fact that many Type B installations may be built up from multiple Type A units and commercial decisions that OEMs may make with this in mind, ie to only supply GFC units which would be stand alone type A or combined into a Type B PPM.

[4] "directly connected" in this context refers to interpretation of Article 20.4 which states that grid forming is mandatory for Type B PPMs connected at 110kV or above, or to a dedicated feeder (of any voltage) which is connected to a substation which operates at 110kV.

Hence, the growth of PPMs within a DSO's network over the coming decades is a key input into establishing the economic basis for the roadmap. There will be a trade-off between the costs of implementing mitigation measures in the DSO's system versus the benefits of PPMs being GFC. DSOs should be prepared to use, and if necessary, improve, their network development plans to provide the best defensible view of the growth of PPMs in their networks.

As part of planning and managing their networks, DSOs should implement ways to track the volumes and locations of GFC PPMs as an addition to their normal record keeping.

Relative risk of a stable island being formed

For the purpose of this support document the illustrative scenarios described have been developed which are intended to cover many of the topological variations of distribution networks at various voltages. In each scenario, and in reality, an island is formed following the operation of specific circuit breakers or switching devices. Each DSO will have to use the knowledge of their own grid to assess how likely or not such an occurrence would be in the context of their networks, accounting for variations in topology, protection schemes etc. The switching actions in consideration here will generally be the tripping of automatic circuit breakers associated with a fault, but switching for any reason, such as preplanned network reconfiguration, could potentially result in an island.

For networks which operate in a radial configuration, any switching action could leave the downstream network potentially operating as an island, if there is generation operating downstream of the switch.

For more complex or meshed systems, such as are common at MV and HV, where the system is in its normal (ie intact) state, a single switching is unlikely to lead to the formation of an uncontrolled island.

It is also possible, although much less likely, that an island may form for reasons other than switchgear operation, for example the operation of MV fuses, or even an open circuit fault on the DSO's system which is not initially identified as a fault. DSOs should evaluate these risks for their own networks.

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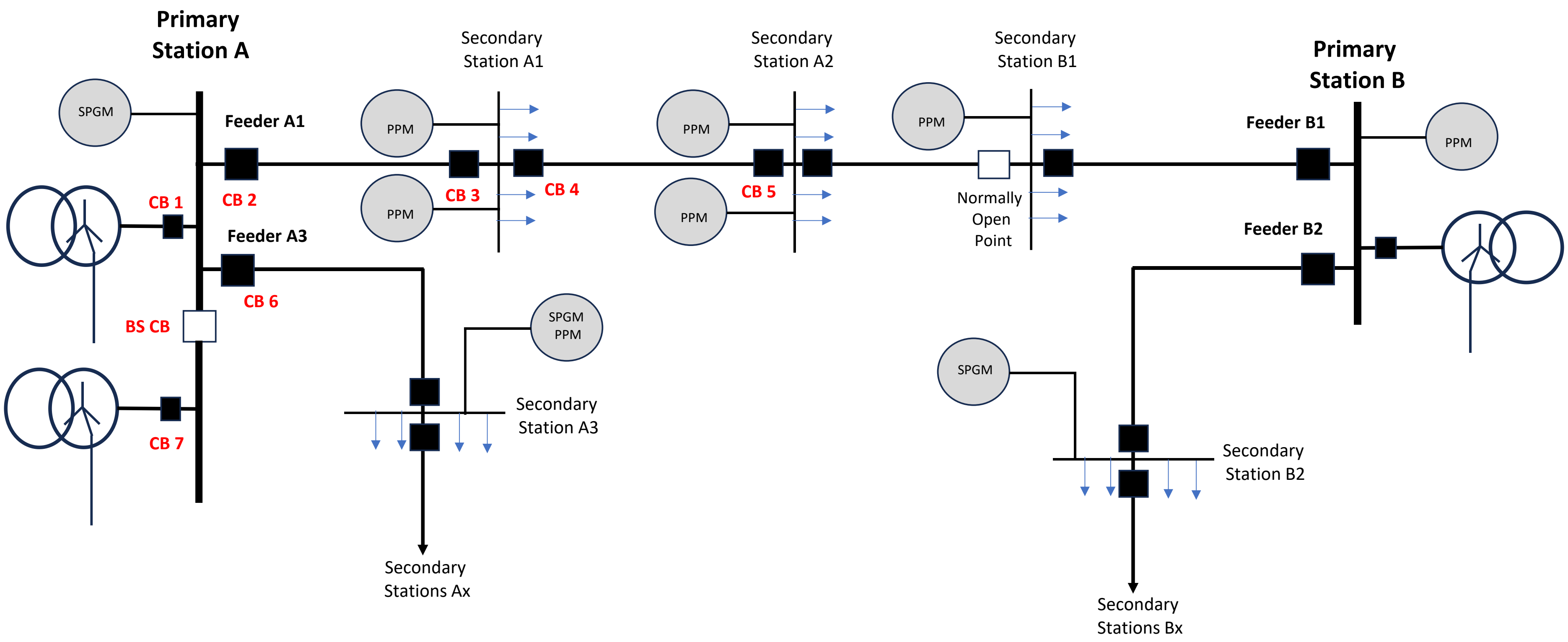

Figure 3 – Schematic of a typical radial distribution network

For example from Figure 3, consider the network supplied by Primary Substation A. For the downstream network to be completely islanded it would need both CB1 and CB7 to be opened (or CB1 and the BS CB). The possible circumstances where both might operate could include:

- A busbar fault
- Failure of feeder level protection to clear a downstream fault
- A maloperation whereby during the planned outage of one transformer, the CB of the other transformer was inadvertently opened.
- A switching error
- Etc

Conversely for the network down stream of CB4 (say) the opening of CB4 for whatever reason (typically an MV fault) would lead to an islanding of the network downstream of CB4.

Relative risk of island being maintained

In the illustrative examples developed below, for various cases, the ratio or mismatch between the level of generation and load is determined. This informs the relative risk of the island being maintained, once formed.

It is further assumed that the generation in the island includes at least one SPGM or GFC PPM which will allow other grid following PGMs to maintain generation. For this reason, where present, GFC PGMs are included in the summation figures for generation on the islands formed in the examples below.

Of course, while GFC functionality will try to maintain the island, irrespective of the governor frequency droop characteristic, if the generation is significantly less than the load, the frequency cannot be maintained and the island will collapse.

For the sub-cases where the generation capacity exceeds the trapped load on the island, it is possible that the governors will maintain the frequency by adjusting the real power output – although of course there are limits to how far generation can reduce its output and remain stable.

These relative risk categories, for the purposes of this support document are given in table 2 below.

Generation/Load mis-match [%]	Risk Category
0 % =<20%	Extremely low
>20 % =<40%	Very low
>40 % =<60%	Low
>60 % =<80%	Medium
>80 % =<100%	High
>100%	High - will need further network specific analysis.

Table 2 Relative risk categories of island being maintained.

Considering a study carried out of RWTH Aachen University[5], in the table above mentioned, beyond the generation/load mis-match [%] parameter, it is very important also to consider the ratio between capacity of GFC PPMs and the total generation capacity included in the considered island. A penetration of GFC

[5] https://publications.rwth-aachen.de/record/985500

capacity of over 20/30% of the total generation in the island produces a very strong likelihood of islanding phenomenon formation undetectable by the commonly used existing techniques.

It is also noted that for synchronous generators, even though in principle they may appear to have more generating capacity than the load of the island, there may be particular load rejection envelopes in place that may limit their ability to sustain the island.

As an illustration of this risk analysis consider the network of Figure 3 again, and assume that there is generation and load dispersed over the network as per Table 3.

Primary Substation	Feeders	Secondary substations fed	Total Load [MW][6]	Total Generation [MW]		
				Grid Following	Grid Forming	Synchronous PGMs
A	Busbar		0			9
	A1	A1	10	4	6	
		A2	8	7	1	
	A3	A3	6	3		2
		Other stations not shown [Ax]	12	4	6	
	Total		36	18	13	11
B	Busbar		8	4	4	
	B1	B1	12	5	7	
		B2	11			11
		Other stations not shown [Bx]	13	4	9	
	Total		44	13	20	11

Table 3 Normal HV feeding, generation and loads.

Note that figures in this table are arbitrary and for illustrative purposes only.

If we assume that the bus section circuit breaker (BS CB) is open, and then CB1 opens (for whatever reason), substations A1, A2 and A3 will all be islanded. Taking into account the loads and generation at these substations, the following analysis can be performed:

Total summated generation [MW]	42
Total trapped load [MW]	36
Generation/Load mis-match [%]	42/36 = 117%
Plausible risk of islanding	High - will need further network specific analysis.

[6] Load on the island at the time under consideration.

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Table 4 – Risk analysis for islanding of substations A1, A2, A3.

Appendix A includes additional details of the above analysis and further examples of islanding risk assessment for different network types/topologies/voltages

The risks of a temporary island as an influence on automatic network reconfiguration

In recent years DSOs have increased substantially the amount of remote control and automatic network management, principally aimed at reducing the duration of interruptions to customers. In general, these schemes react to a fault on the DSO network, and following the opening of the relevant circuit breaker, automatically react to reconfigure the system with the aim of restoring the greatest number of customer supplies in the shortest possible time. They range in complexity from a simple auto-reclose of the tripped circuit breaker, to complex network re-arrangement schemes, with sequence switching at multiple locations.

Such schemes generally do not take account of any island that may form, assuming that the entire network is dead downstream of the tripped circuit breaker. There are at least two undesirable consequences of an island where the scheme does not expect it. If the island is not detected, then the scheme will close up switchgear between the island and the rest of the system irrespective that two frequencies and phasing will not be aligned. This "crash synchronization" may not have any particular adverse consequences in general, although it will likely be a challenging or damaging even for any synchronous generation or electric motor running in the power island. However, the overall effects of "crash synchronizations" are not well observed or documented, so it may be unwise to create more opportunities and instances. In the case where an automatic restoration scheme does check for the presence, and/or phasing, of voltage in the downstream network, the presence of voltage, indicating a power island, will in most cases cause the scheme to cease/fail as schemes with voltage sensing are designed not to "crash sync" the network.

DSOs' analysis of the risks of GFC PPMs will need to specifically consider these issues.

Influence of frequency based automatic load/generation shedding on the mismatch between generation and load

One issue for DSOs to be aware of is the effect of frequency-based shedding on islanding risk, such as LFDD as defined in the European Network code for Emergency and Restoration (Commission Regulation (EU) 2017/2196). There have already been cases where islands have formed and survived despite there being a considerable and unsustainable excess of load over generation. However, in these cases the network has included low frequency demand shedding arrangements designed to help protect the overall intact system from frequency excursions. In the island situations observed here, as the frequency falls after the island formation, the low frequency demand shedding scheme has operated and disconnected sufficient demand such that the generation in the island is able to stabilise and support the remaining loads. DSOs should consider the presence and effect of such schemes when analysing the islanding risks.

Note also, that these examples represent snapshots of what, in reality, would be an evolving situation. In practice, the quantum of load and/or total generation, will likely change as the event develops. A statistical analysis or a max/min assessment could be used.

Appendix D illustrates a real case of temporary unwanted islanding where an initially decreasing frequency caused LFDD to operate which removed a significant amount of load, and, consequently, led the frequency to increase. If the generation within the island had frequency adapting characteristics, such as FSM (where it is enabled for market purposes), it could easily have sustained the island.

In addition to LFDD schemes, the draft NC Demand Connection Code submitted by ACER to the European Commission includes the new functionality LFSM-UC (ie limited frequency sensitive mode – underfrequency consumption). This new and necessary functionality, for overall stability purposes, is meant to decrease the consumption of certain types of loads (specifically heat pumps and EVs) in underfrequency events before the frequency reaches the LFDD levels. For distribution islanding probability assessment this new feature must also be considered by DSOs when using the load generation mismatch criterion.

Impact of summated LV connected generation on MV network

Introduction

This category of scenario is considered worthy of particular mention and warrants detailed discussion. Two characteristics of MV to LV transformers are particularly relevant to the discussions and deliberations below with regard to mitigations.

1. Three phase transformers for many DSOs' networks tend to be designed with a delta connected MV winding, and star connected LV winding.
2. The very large numbers of them.

General single transformer arrangement

Figure 4 below depicts a single transformer instance. In case an island has been formed it will operate with an isolated neutral, since whatever neutral treatment was in place at the primary substation in the intact network, it is no longer connected.

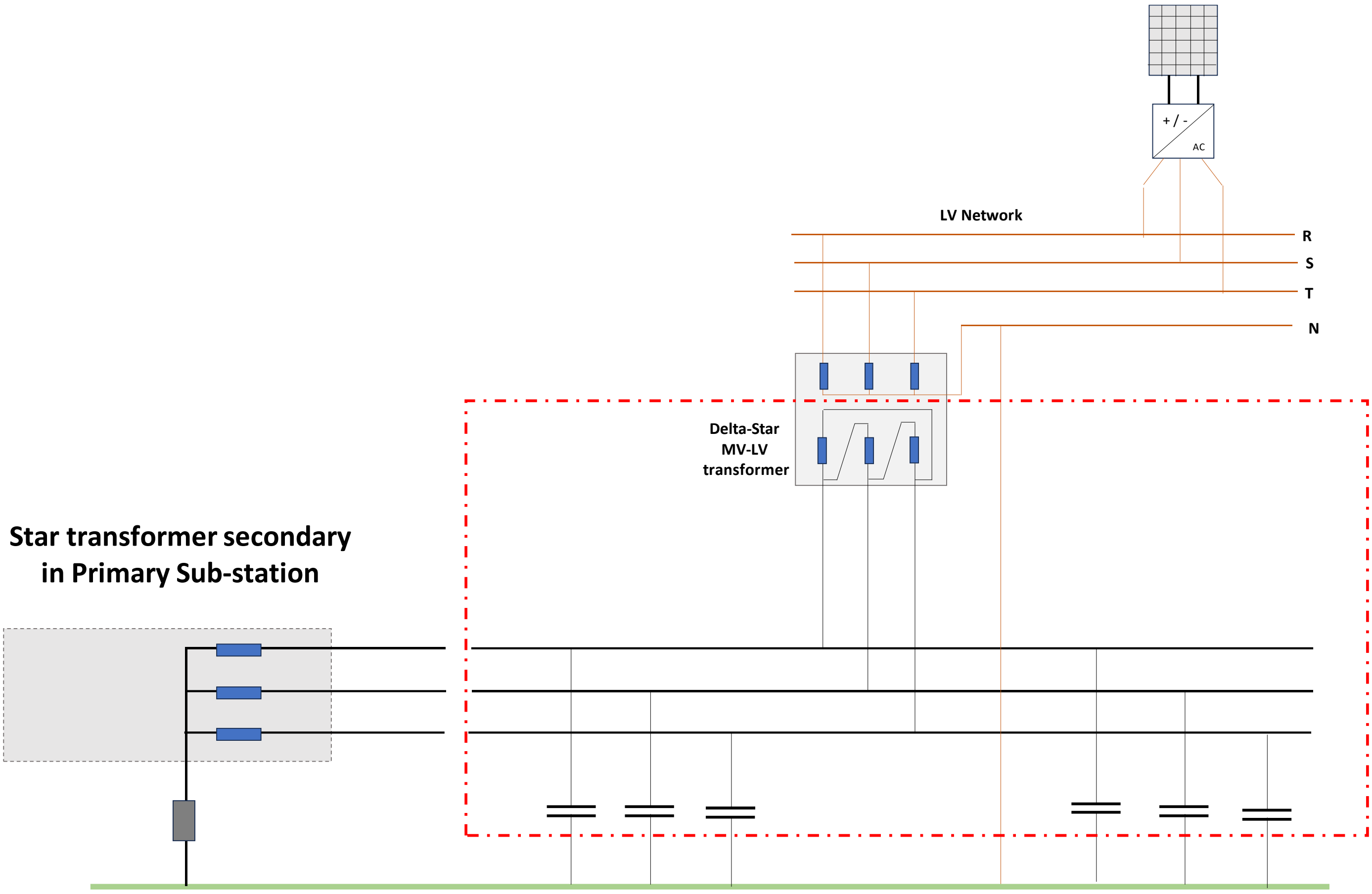

Figure 4 Schematic representation of MV/LV transformer and GFC generator on isolated neutral MV island (distributed line capacitance is represented by a capacitor for illustration purposes)

A GFC invertor is shown connected to the LV network which in turn is connected to the delta-star MV-LV transformer. Load is assumed to be present on the LV and MV networks but not shown.

As stated earlier, there is no intentional neutral earthing on the isolated MV island. Phase to earth capacitances are shown. The quantum of capacitance will be a function of the size (in km) of the network and its nature (overhead line versus underground cable).

It is assumed that when the islanded network is disconnected from the primary sub-station, the GFC invertor will keep the network live and will attempt to feed the load, subject to there being an appropriate and manageable load/generation balance.

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Single phase to earth fault on the MV network island

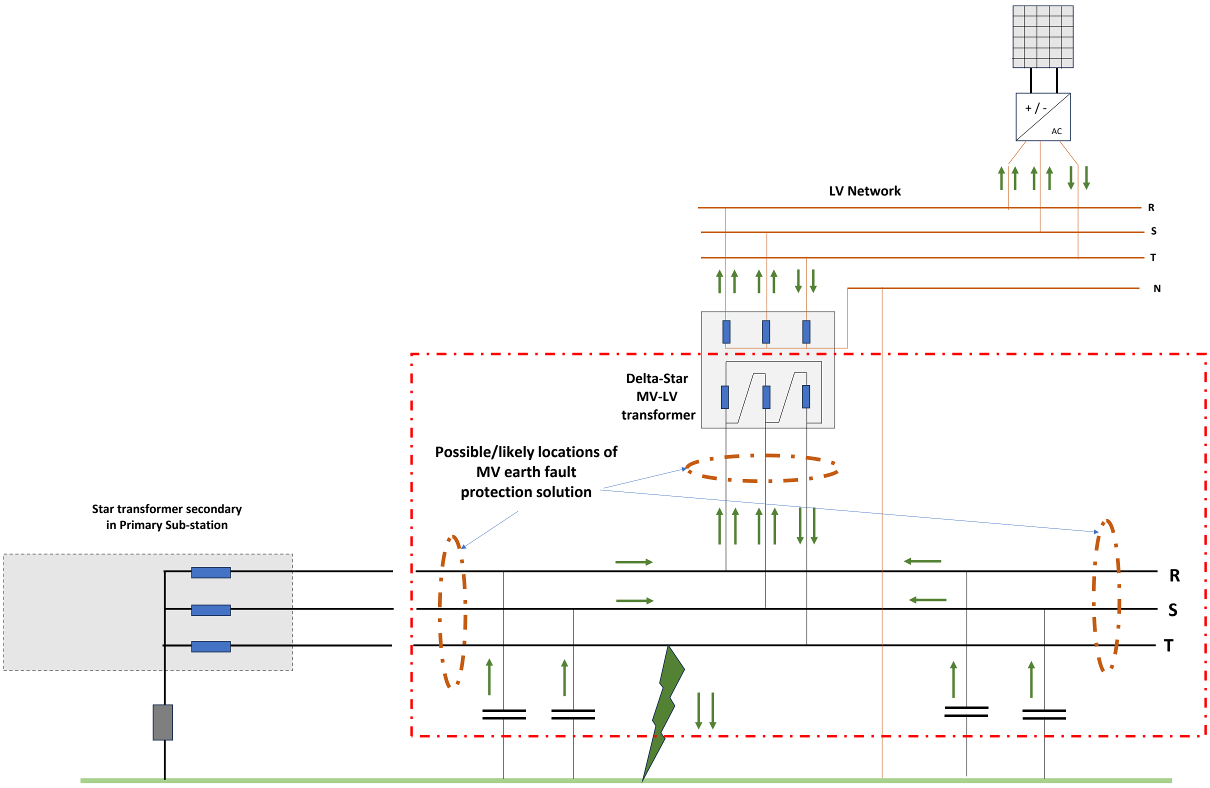

Figure 5 Single phase to earth MV fault

Figure 5 shows the situation when a single phase to earth fault occurs on the MV network. The fault (and associated public safety risk) is being maintained or fed by the GFC invertor connected to the low voltage network.

This situation could exist when the fault causes the islanding, ie the earth fault current triggers the MV protection, disconnecting the MV network at the primary sub-station or other downstream device. Or it could also be the case that following an inadvertent islanding of the MV network, for example by a circuit breaker opened in error, the earth fault occurs subsequently. In either case the safety issues are the same.

The flow of current (excluding any load current) is depicted by the green arrows. The amount of earth fault current at the fault site is a function of the capacitance of the other two healthy phases – R and S in the case shown.

The important point here is that this MV fault cannot be directly detected on the LV network, including by any generator interface protection at the generation connection point. The MV fault needs to be detected by non-traditional means. These could include.

- Neutral voltage displacement
- SCADA indications and measurements

There is no single point to deploy such protection. An obvious place might be at the LV/MV transformation point, but neutral voltage displacement can be measured anywhere on the MV system. In some cases it can be hard to find a neutral voltage displacement setting that works, taking

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into account the nature of the network and its inherent unbalance. Even if these techniques can detect the island and the fault, there is then the question of how to control the island such that the dangers of the earth fault are addressed. If the detection is undertaken at the LV/MV transformation point, then separating the MV system from the LV system here would solve the safety issues – but this would depend on there being suitable switchgear[7] at this site as well as the detection equipment. Another option would be for the detection of the MV fault to initiate a trip of all the LV (and MV) connected generation – although this would require significant communication infrastructure and backup plans for communication failure events.

Islands on LV networks

In general, it is assumed that the neutral in distribution LV networks is multiple earthed, which is believed to be common in most member states. An island could occur any time that a DSO low voltage switching point is opened, or a set of LV fuses operate.

The former case here could pertain either because of a fault which has been detected and the switchgear operated automatically, or it could be a planned action to disconnect the downstream network. In the latter case, this will usually be associated with a fault on the LV network that, at least at the time of the fault, affects all three phases.

Where there is an operation of switchgear with no fault on the network, the island may form with the connected loads being supplied by the connected generation. If there is a reasonable load/generation balance this situation may persist for some time. On its own, this situation does not present an unsafe situation, but it would do so should there be any fault on the network at that time or subsequently.

Where this is a fault on the LV network, and the network is disconnected by the operation of the DSO's switchgear or fuses, generation connected to the faulted part of the network may be able to sustain an island if there is a load/generation balance. However, if the fault persists this may or may not operate the protection of individual generation. A low impedance short circuit phase to phase or phase to earth may operate the overcurrent protection of individual generators, but this will depend on several factors. Three phase generators may or may not be able to detect earth faults, depending on their earthing arrangements. Single phase generators will be unaffected by phase-phase faults, but may detect earth faults as overload or overcurrent. In all these cases the public safety issues are real but somewhat less than those at MV.

It is also worth noting that should an LV island be present, fed by inverter based generation, it is highly unlikely that there will be enough fault current from even multiple inverters to operate any of the existing standard DSO protection, such as fuses.

Customers with GFC generation on their premises, for example domestic PV, may wish to go into island mode themselves, either during a network fault or outage. A key requirement though, is that the interface protection and the isolating device that the interface protection trips or customer elects to operate, is designed and installed to a technical standard agreed by the DSO. In such a scenario, this is a positive outcome for the customer and the GFC device is no longer adding to the risks considered here.

[7] In isolated neutral situations the earth fault currents are small and even in the case of three-phase faults the inverter limits the current to a value close to the rated power which means the switch gear sizing can, potentially, be carried out for the load current.

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Part 2: Analysis: Consequences of, and potential mitigations for, island formation

Introduction

In the preceding sections the risk of islands forming and being maintained was discussed, with some illustrative examples in a high GFC penetration scenario. In this section, the consequences of island formation and potential mitigation measures are discussed.

In the analysis below an important consideration is the earthing, or otherwise, of the neutral. Another consideration is the cause of the separation of the islanded network from the rest of the intact network – specifically whether this was due to the occurrence of a network fault. Furthermore, whether that fault was a single phase to earth fault or a phase-to-phase fault. For this reason, several permutations are depicted and discussed.

It is also noted that irrespective of the neutral treatment in place for intact distribution network, once the island is formed and the islanded network is separated from the normal primary feeding primary substation[8], then it will by default operate as an isolated neutral network.

General Format of discussions

General format will be as follows:

- Risk
- Impact
- Mitigation
- Post Mitigation Risk
- Concluding Remarks.
- Order of magnitude costs (where relevant).

[8] ie no longer interconnected with the rest of system.

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Risk 1

- For an intact network, earth fault protection is current based using a resistance or directly earthed neutral.
- Islanded network operates as an isolated neutral network. No earth fault protection available in the island, in the event of a single phase to earth fault.

No.	Possible Mitigation	Where?	Ref.	Discussion	Conclusion	Order of magnitude cost [€k/instance]
1	To maintain the use of current based protection, form a neutral and earth it.	• At all grid-forming PPMs and SPGMs connected. • At all transformers that have generation [single or summated] connected to its lower voltage side.	A1	Apart from the physical difficulties in forming a star-point and costs etc., there is a fundamental issue with this approach is that if left permanently in place, they would provide multiple parallel paths for fault current in the event of a fault on the intact network. This would severely compromise the effectiveness and operation of current based protection at the primary substation.	This mitigation not considered further.	
2	Form a neutral and earth it via a switch.		A2	The idea here is that the neutral earth switch is normally in the open position and that by some means, the switch would be closed in the event of the island formed. Whilst this would solve the earth fault current splitting issue above, it raises several other issues. It is not clear how it would be known at the site, that the islanding has occurred. An effective island detection system would still be required at each site. Also not clear if there would be sufficient fault current to operate protection reliably.	Technically possible but impractical and extremely expensive for large volumes.	
3	Install residual voltage-based protection.			This would require many components that would normally be associated with a primary HV sub-station, such as; - An earthing transformer with a Voltage Transformer [VT]on the neutral. - A Voltage Transformer [VT] arrangement capable of generating an open delta voltage - Residual voltage relaying	Technically possible but impractical and extremely expensive for large volumes.	€50k[9]

[9] See costs breakdown in Appendix C

No.	Possible Mitigation	Where?	Ref.	Discussion	Conclusion	Order of magnitude cost [€k/instance]
				- A device to trip		
5	Install self-contained MV reclosers with capacitive VT bushings and a form of earth fault protection.		A2	A separate undervoltage element per phase on voltage to earth could provide reasonably good earth fault protection.	For MV/LV sites, this could be a viable solution.	
6	Install residual voltage-based protection and a fault throw switch.	Strategic locations such as to maximise the possibility of at least one such instance being on any island formed.	B1	The idea here is that on the occurrence of an earth fault, the fault-throw switch would cause a bolted short-circuit and force normal overcurrent protection to operate. Big downside, operation on an intact network would be very undesirable, complicate and confuse restoration operations.	This could be an effective albeit, extremely crude solution. Not considered any further.	
7	Install residual voltage-based protection and a fault throw switch plus a blocking signal.		B2	Would eliminate system intact operation.	Challenge would be to find a reliable means of providing a blocking signal for system intact conditions. Not considered any further.	
8	Centralised intelligence with logic to determine situations where a section of modelled network is isolated from the rest but the presence of voltage and/or current is still indicated.	In the connected model of an Advanced Distribution Management System [ADMS].	C1	Most Operations Technology [OT] vendors would have such functionality, or it could be configured to do so, relatively easily.	If the DSO concerned has or is investing in ADMS, very small incremental costs. In case of a [smaller] DSO who has no such intentions, the costs would be very high but other benefits could realised from the increased visibility arising.	Very DSO and project specific
9	Install residual voltage-based protection and intertrip all/relevant generation	Strategic locations such as to maximise the possibility of at least one such instance being on any island formed.	C2	This would be an extension of the approach already planned or taken in some DSOs. However the wide application of this, ie thousands and thousands of LV networks and LV connected generators, suggest this would a challenge and possibly uneconomic cf other solutions.	Further exploration of the costs and implications needed. Not considered any further.	

Table 5: Mitigation for Risk

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Risk 2:

- For an intact network, earth fault protection is based on a Petersen coil on the neutral
- Islanded network operates as an isolated neutral network.

Impact	No.	Possible Mitigation	Where?	Ref.	Discussion	Conclusion
Plant damage - over-voltages due to the absence of the Petersen coil to limit the magnitude of voltage to earth during a single phase-earth fault, and insulation levels are not adequate	D1	Increase insulation level	On all network plant		Absolutely prohibitive cost	Not considered further
	D2	Investigate if lightning arrester MOV levels could be tweaked.	On all OH/UG transitions		Still may be very costly	Might be possible

Table 6: Mitigation for Risk 2t

Conclusion

Table 5 and Table 6 above explore the various technical mitigating solutions, that are known to the authors at the time of writing. Most are impractical to implement for the reasons stated.

For MV networks, the most viable and readily implementable solutions are A1 and A2 (for all kinds of neutral earthing technic adopted). For small numbers, this is probably viable. However, it should be noted that the outcome of this analysis is that this solution has to be installed at every MV/LV transformer site, then the total cost and effort may be judged to be disproportionate.

For HV networks, the C1 mitigation is very attractive, particularly where DSOs are already moving towards ADMS implementation. In such cases, the incremental costs would be minimal.

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Appendix A

Examples of islanding risk assessment for different network types/topologies/voltage

High Penetration HV connected illustrative scenarios

Scenario 1: CB 1 opens

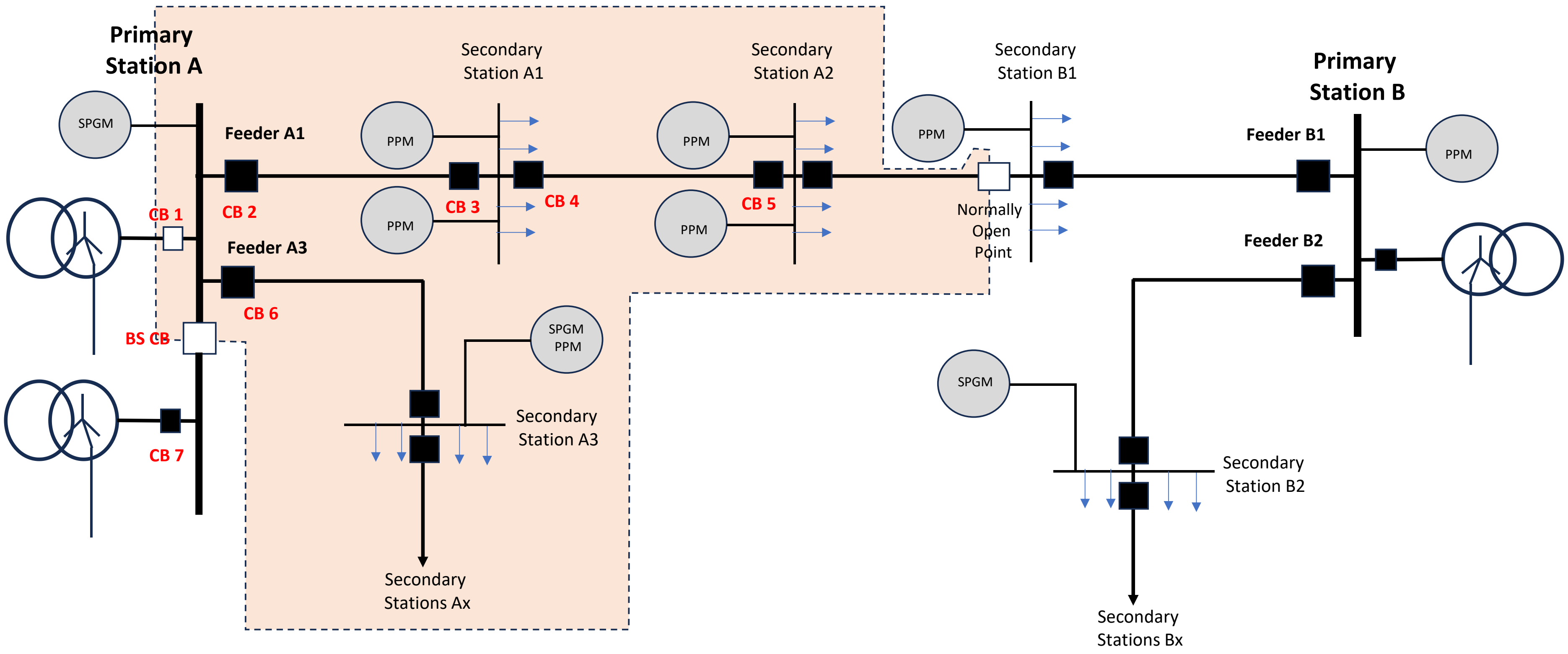

Figure 6 : Island formed by opening of CB1

Primary Substation	Feeders	Secondary substations fed	Total Load[10] [MW]	Total Generation [MW]		
				Grid Following	Grid Forming	Synchronous PGMs
A	Busbar		0			9
	A1	A1	10	4	6	
		A2	8	7	1	
	A3	A3	6	3		2
		Other stations not shown [Ax]	12	4	6	
	Total		36	18	13	11

Table A. 1 – Scheme of description for assumed distribution network with generation and load – SCENARIO 1

Total summated generation [MW]	42
Total trapped load [MW]	36
Generation/Load mis-match [%]	42/36 = 116%
Plausible risk of islanding	High – will need further specific analysis

Table A. 2 – Comparison of generation and load into the considered island – SCENARIO 1

[10]Load on the island at the time under consideration.

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Scenario 2: CB 2 opens

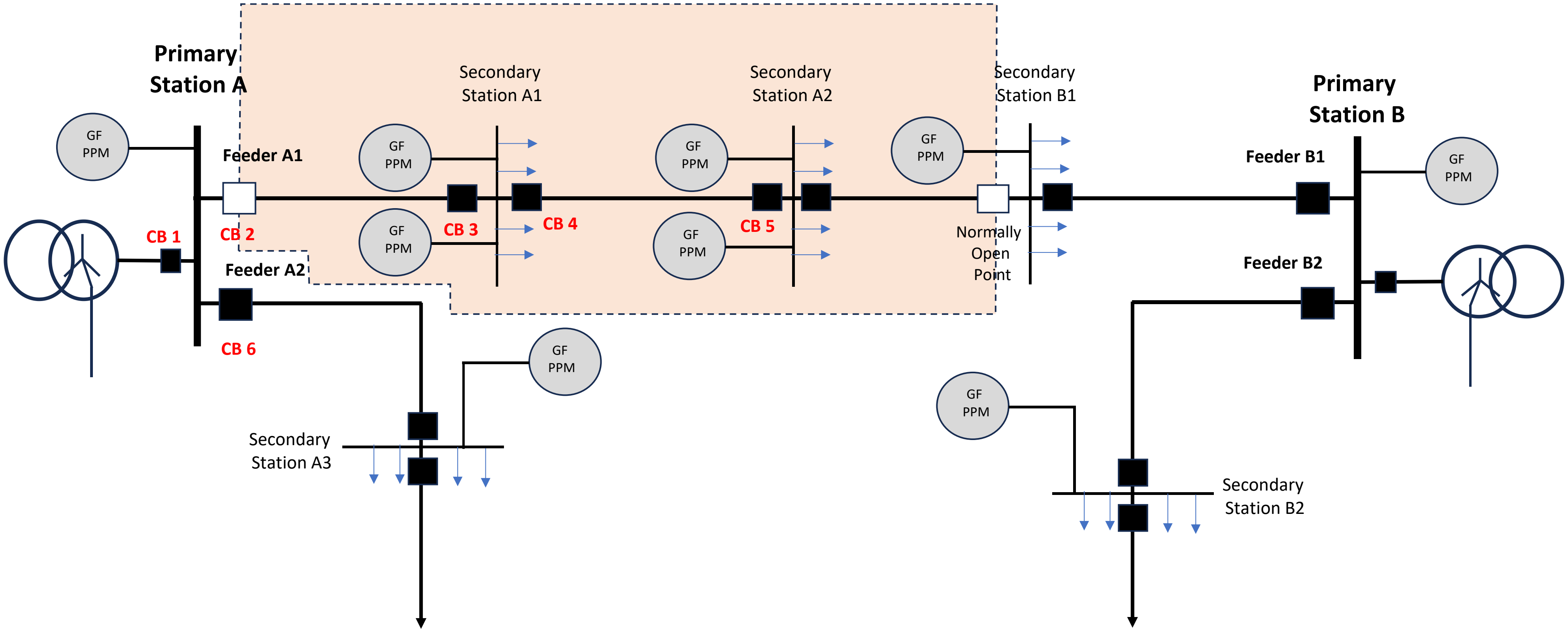

Figure 7 Island formed by opening of CB2

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<table>
<tr><th rowspan="2">Primary Substation</th><th rowspan="2">Feeders</th><th rowspan="2">Secondary substations fed</th><th rowspan="2">Total Load [11] [MW]</th><th colspan="3">Total Generation [MW]</th></tr>
<tr><th>Grid Following</th><th>Grid Forming</th><th>Synchronous PGMs</th></tr>
<tr><td rowspan="6">A</td><td colspan="2">Busbar</td><td>0</td><td></td><td></td><td>9</td></tr>
<tr><td rowspan="2">A1</td><td>A1</td><td>10</td><td>4</td><td>6</td><td></td></tr>
<tr><td>A2</td><td>8</td><td>7</td><td>1</td><td></td></tr>
<tr><td rowspan="2">A3</td><td>A3</td><td>6</td><td>3</td><td></td><td>2</td></tr>
<tr><td>Other stations not shown [Ax]</td><td>12</td><td>4</td><td>6</td><td></td></tr>
<tr><td colspan="2">Total</td><td>18</td><td>11</td><td>7</td><td></td></tr>
</table>

Table A. 3 - Scheme of description for assumed distribution network with generation and load – SCENARIO 2

Total summated generation [MW]	18
Total trapped load [MW]	18
Generation/Load mis-match [%]	18/18 = 100%
Plausible risk of islanding	High

Table A. 4 - Comparison of generation and load into the considered island – SCENARIO 2

[11] Load on the island at the time under consideration.

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Scenario 3: CB 4 opens

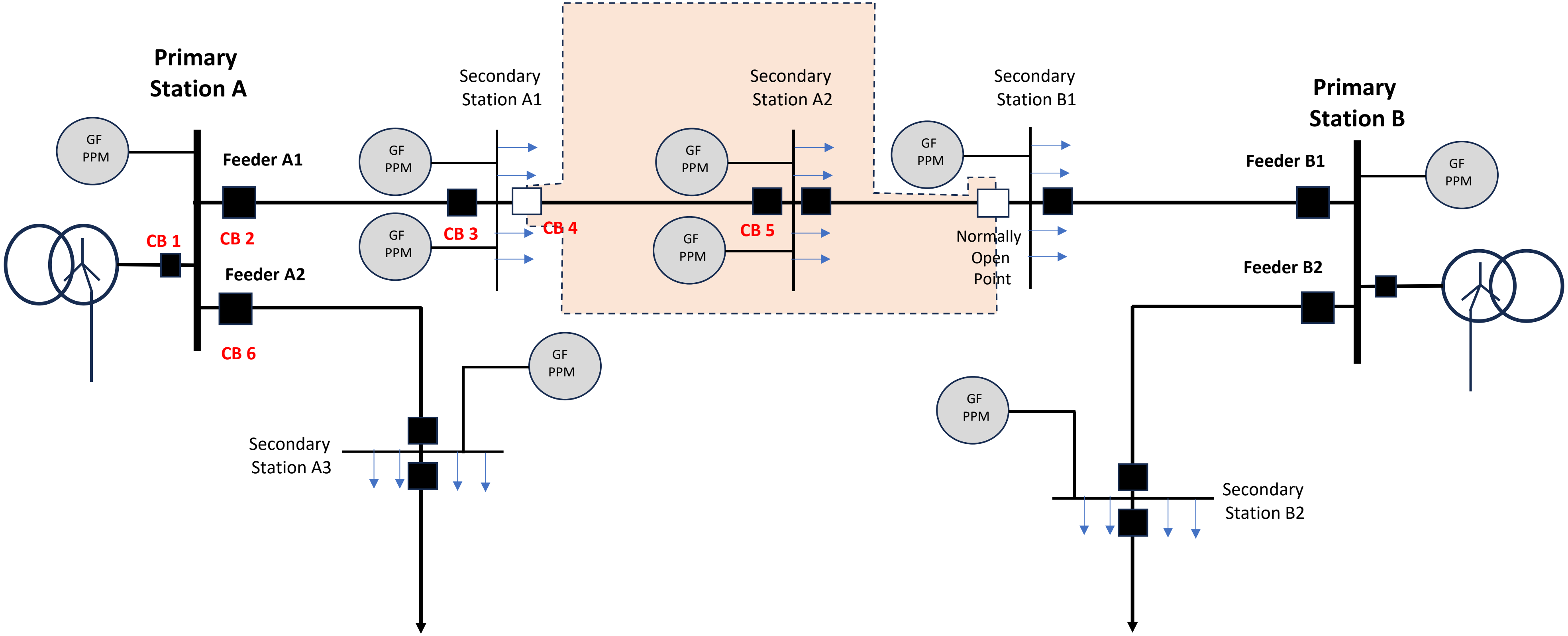

Figure 8 Island formed by opening CB4

Primary Substation	Feeders	Secondary substations fed	Total Load[12] [MW]	Total Generation [MW]		
				Grid Following	Grid Forming	Synchronous PGMs
A	Busbar		0			9
	A1	A1	10	4	6	
		A2	8	7	1	
	A3	A3	6	3		2
		Other stations not shown [Ax]	12	4	6	
	Total		8	7	1	11

Table A. 5 - Scheme of description for assumed distribution network with generation and load – SCENARIO 3

Total summated generation [MW]	8
Total trapped load [MW]	8
Generation/Load mis-match [%]	8/8 = 100%
Plausible risk of islanding	High

Table A. 6 - Comparison of generation and load into the considered island – SCENARIO 3

[12] Load on the island at the time under consideration.

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Scenario 4: Circuit from Secondary station B1 to Primary Station B switched out and CB 2 opens

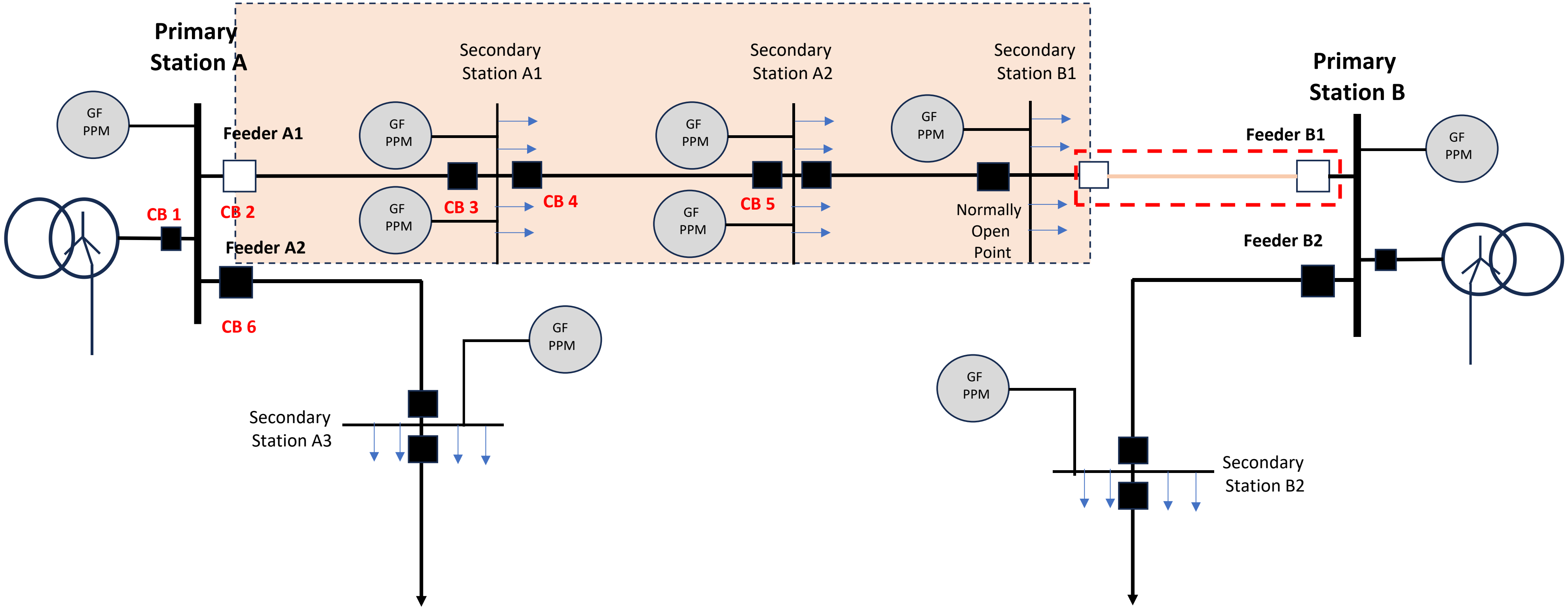

Figure 9 Secondary B1 fed from Primary A due to outage of circuit and CB2 opens

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Primary Substation	Feeders	Secondary substations fed	Total Load[13] [MW]	Total Generation [MW]		
				Grid Following	Grid Forming	Synchronous PGMs
A	Busbar		0			9
	A1	A1	10	4	6	
		A2	8	7	1	
	A3	A3	6	3		2
		Other stations not shown [Ax]	12	4	6	
	Total		36	18	13	11
B	Busbar		8	4	4	
	B1	B1	12	5	7	
		B2	6			11
		Other stations not shown [Bx]	14	4	9	
	Total		30	16	14	0

Table A. 7 - Scheme of description for assumed distribution network with generation and load – SCENARIO 4

Total summated generation [MW]	30
Total trapped load [MW]	30
Generation/Load mis-match [%]	30/30 = 100
Plausible risk of islanding	High

Table A. 8 - Comparison of generation and load into the considered island – SCENARIO 4

[13]Load on the island at the time under consideration.

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High Penetration illustrative scenarios: HV connected including underlying generation

In this section, the generic schematic and illustrative analysis now also takes into account the summated generation connected to the lower voltage busbars of some of the stations. The methodology could be applied to a HV/MV or MV/LV context. The same principles will apply in either case. The generic schematic is depicted in figure 10 below.

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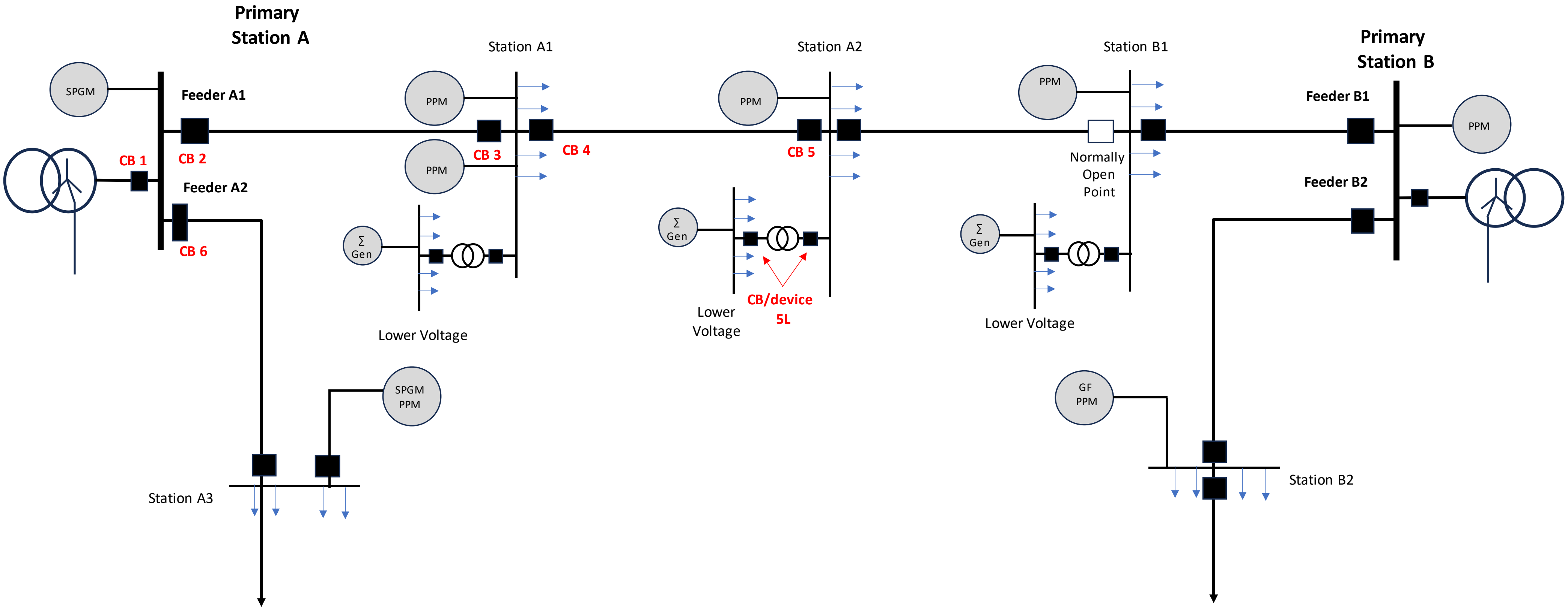

Figure 10 Generic schematic showing generation from lower voltage busbar

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Notes on Generic HV System Schematic with lower voltage

1. Neutral treatment is not depicted here. It is not deemed to be relevant for these particular considerations. It will feature and be discussed at length in other sections of this document.
2. Two primary substations are depicted – designated A and B
3. Each primary substation may have two transformers but only one is shown here for convenience.
4. Each has two feeders shown, designated A1 and A2 for Station A, B1 and B2 for station B.
5. Secondary substations are also shown.
6. Primary Station A normally feeds substations A1, A2 and A3.
7. Primary Station B normally feeds substations B1, B2.
8. Stations A1, A2 and B1 have summated generation and loads connected to their lower voltage busbars.
9. Initially, for normal feeding, all CB's or other switching/disconnecting devices, are shown as closed except the normally open point in Secondary Station B1.
10. Generation is also connected to the busbar of both primary substations
11. The magnitude of the HV voltage is not shown.

Primary Substation	Feeders	Secondary substations fed	Total Load [MW][14]	Total Generation [MW]		
				Grid Following	Grid Forming	Synchronous PGMs
A	Busbar		0			9
	A1	A1	10	4	6	
		A1 lower voltage Busbar	3	0.5	4	1
		A2	8	7	1	
		A2 lower voltage Busbar	4	1	4	
	A3	A3	6	3		2
		Other stations not shown [Ax]	12	4	6	
	Total		43	19.5	21	12
B	Busbar		8	4	4	
	B1	B1	12	5	7	
		B1 lower voltage Busbar	2		5	
	B2	B2	6			11
		Other stations not shown [Bx]	14	4	9	
	Total		42	13	25	11

Table A. 9 - Scheme of description for assumed distribution network with generation and load – SCENARIO 5

[14] Load on the island at the time under consideration.

Scenario 1A: CB 1 opens

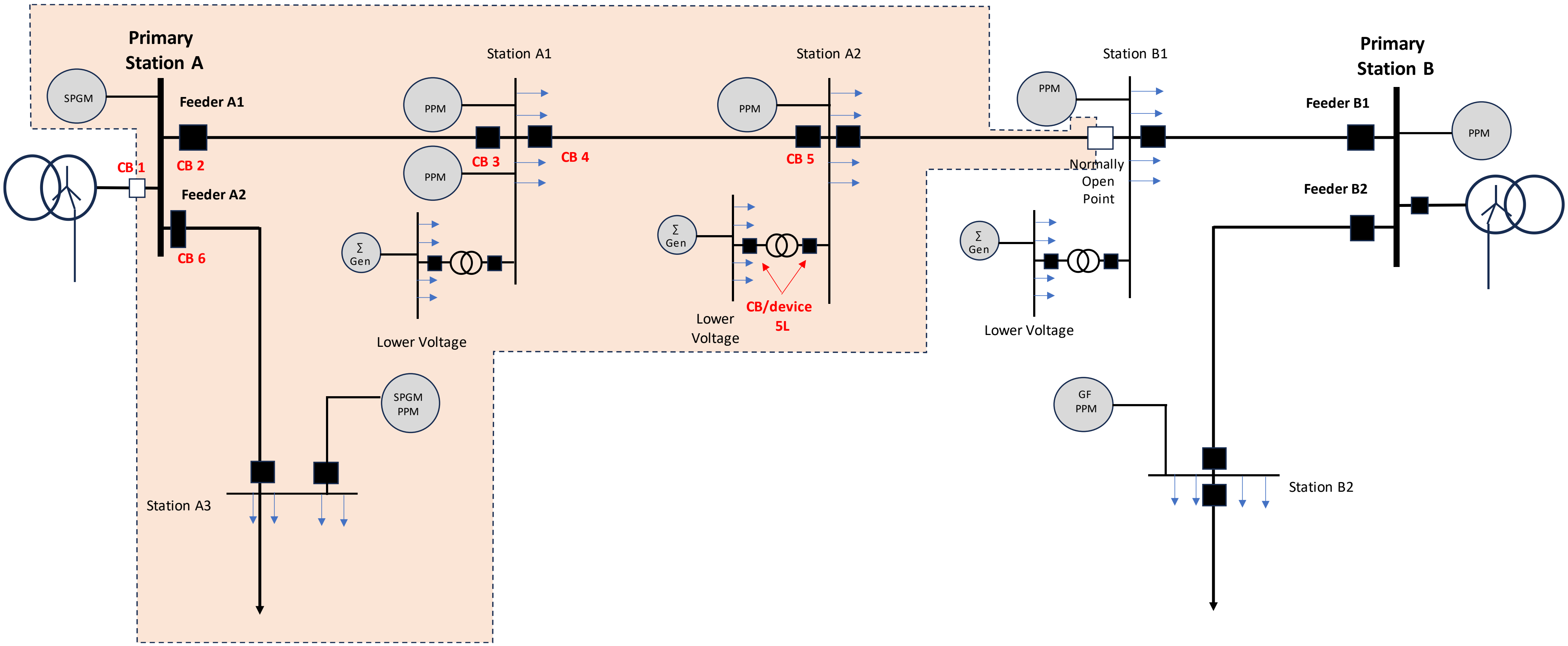

Figure 10: Island formed by opening CB1

Primary Substation	Feeders	Secondary substations fed	Total Load [15] [MW]	Total Generation [MW]		
				Grid Following	Grid Forming	Synchronous PGMs
A	Busbar		0			9
	A1	A1	10	4	6	
		A1 lower voltage Busbar	3	0.5	4	1
		A2	8	7	1	
		A2 lower voltage Busbar	4	1	4	
	A3	A3	6	3		2
		Other stations not shown [Ax]	12	4	6	
	Total		43	19,5	21	12
B	Busbar		8	4	4	
	B1	B1	12	5	7	
		B1 lower voltage Busbar	2		5	
	B2	B2	6			11
		Other stations not shown [Bx]	14	4	9	
	Total		40	13	20	11

Table A. 10 - Scheme of description for assumed distribution network with generation and load – SCENARIO 1A

Total summated generation [MW]	52,5
Total trapped load [MW]	43
Generation/Load mis-match [%]	52.5/43 = 122%
Plausible risk of islanding	High – will need further analysis

Table A. 11 - Comparison of generation and load into the considered island – SCENARIO 1A

[15]Load on the island at the time under consideration.

Scenario 2A: CB 2 opens

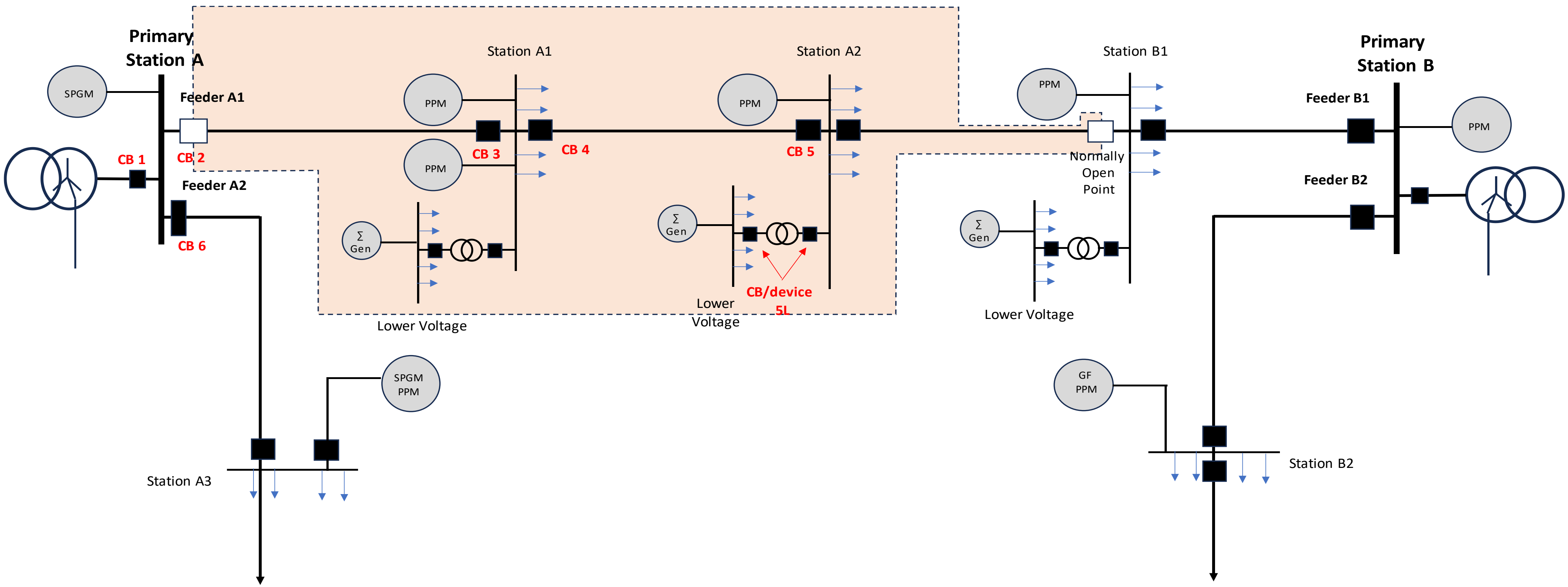

Figure 11: Island formed by opening CB2

Primary Substation	Feeders	Secondary substations fed	Total Load [16] [MW]	Total Generation [MW]		
				Grid Following	Grid Forming	Synchronous PGMs
A	Busbar		0			9
A	A1	A1	10	4	6	
A	A1	A1 lower voltage Busbar	3	0.5	4	1
A	A1	A2	8	7	1	
A	A1	A2 lower voltage Busbar	4	1	4	
A	A3	A3	6	3		2
A	A3	Other stations not shown [Ax]	12	4	6	
A	Total		25	12,5	15	10
B	Busbar		8	4	4	
B	B1	B1	12	5	7	
B	B1	B1 lower voltage Busbar	2		5	
B	B2	B2	6			11
B	B2	Other stations not shown [Bx]	14	4	9	
B	Total		40	13	20	11

Table A. 7 - Scheme of description for assumed distribution network with generation and load – SCENARIO 2A

Total summated generation [MW]	37,5
Total trapped load [MW]	25
Generation/Load mis-match [%]	37.5/25 = 150%
Plausible risk of islanding	High – may need further specific analysis

Table A. 12 - Comparison of generation and load into the considered island – SCENARIO 2A

[16] Load on the island at the time under consideration.

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Scenario 3A: CB 4 opens

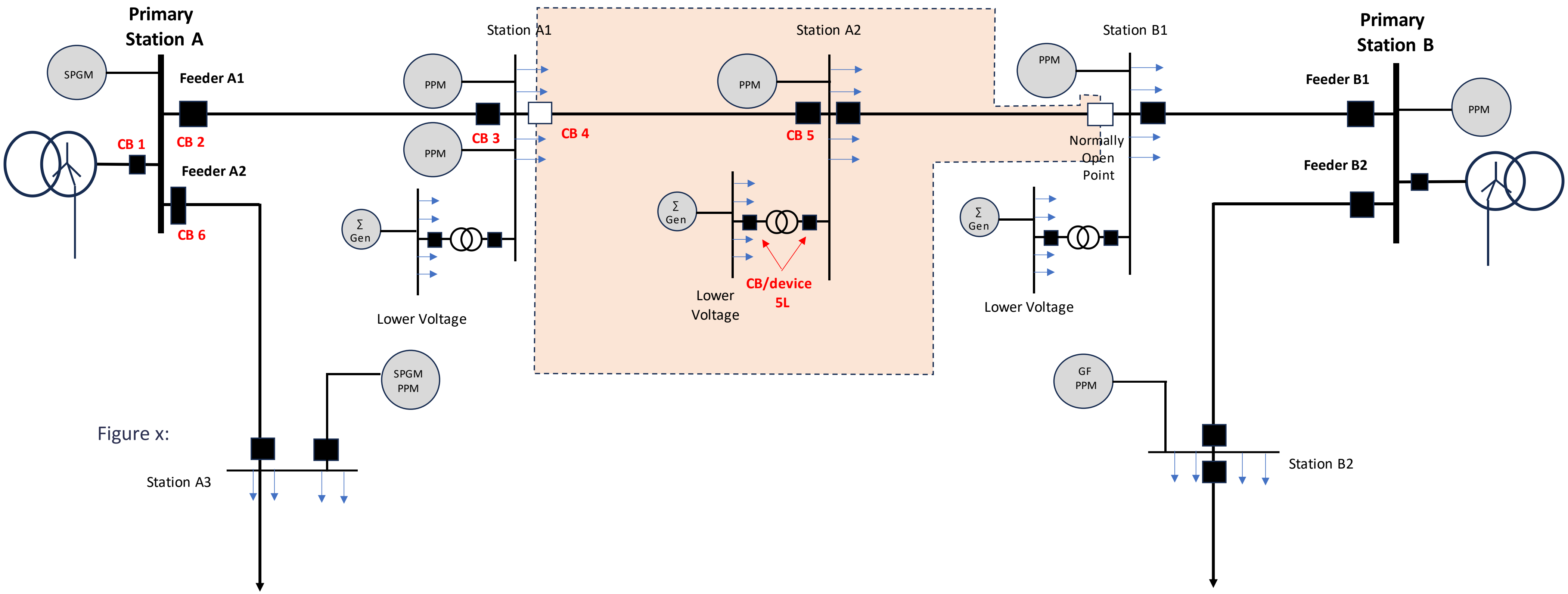

Figure x:

Figure 12: Island formed by opening CB4

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<table>
<tr><th rowspan="2">Primary Substation</th><th rowspan="2">Feeders</th><th rowspan="2">Secondary substations fed</th><th rowspan="2">Total Load [17] [MW]</th><th colspan="3">Total Generation [MW]</th></tr>
<tr><th>Grid Following</th><th>Grid Forming</th><th>Synchronous [SPGMs]</th></tr>
<tr><td rowspan="8">A</td><td colspan="2">Busbar</td><td>0</td><td></td><td></td><td>9</td></tr>
<tr><td rowspan="4">A1</td><td>A1</td><td>10</td><td>4</td><td>6</td><td></td></tr>
<tr><td>A1 lower voltage Busbar</td><td>3</td><td>0.5</td><td>4</td><td>1</td></tr>
<tr><td>A2</td><td>8</td><td>7</td><td>1</td><td></td></tr>
<tr><td>A2 lower voltage Busbar</td><td>4</td><td>1</td><td>4</td><td></td></tr>
<tr><td rowspan="2">A3</td><td>A3</td><td>6</td><td>3</td><td></td><td>2</td></tr>
<tr><td>Other stations not shown [Ax]</td><td>12</td><td>4</td><td>6</td><td></td></tr>
<tr><td colspan="2">Total</td><td>12</td><td>8</td><td>5</td><td>11</td></tr>
<tr><td rowspan="6">B</td><td colspan="2">Busbar</td><td>8</td><td>4</td><td>4</td><td></td></tr>
<tr><td rowspan="2">B1</td><td>B1</td><td>12</td><td>5</td><td>7</td><td></td></tr>
<tr><td>B1 lower voltage Busbar</td><td>2</td><td></td><td>5</td><td></td></tr>
<tr><td rowspan="2">B2</td><td>B2</td><td>6</td><td></td><td></td><td>11</td></tr>
<tr><td>Other stations not shown [Bx]</td><td>14</td><td>4</td><td>9</td><td></td></tr>
<tr><td colspan="2">Total</td><td>40</td><td>13</td><td>20</td><td>11</td></tr>
</table>

Table A. 13 - Scheme of description for assumed distribution network with generation and load – SCENARIO 3A

Total SPGM and Gfc generation [MW]	13
Total trapped load [MW]	12
Generation/Load mis-match [%]	13/12 = 108%
Plausible risk of islanding	High – may need further specific analysis

Table A. 14 - Consistency of generation and load into the considered island – SCENARIO 3A

[17] Load on the island at the time under consideration.

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Scenario 4A: CB/Device 5L opens

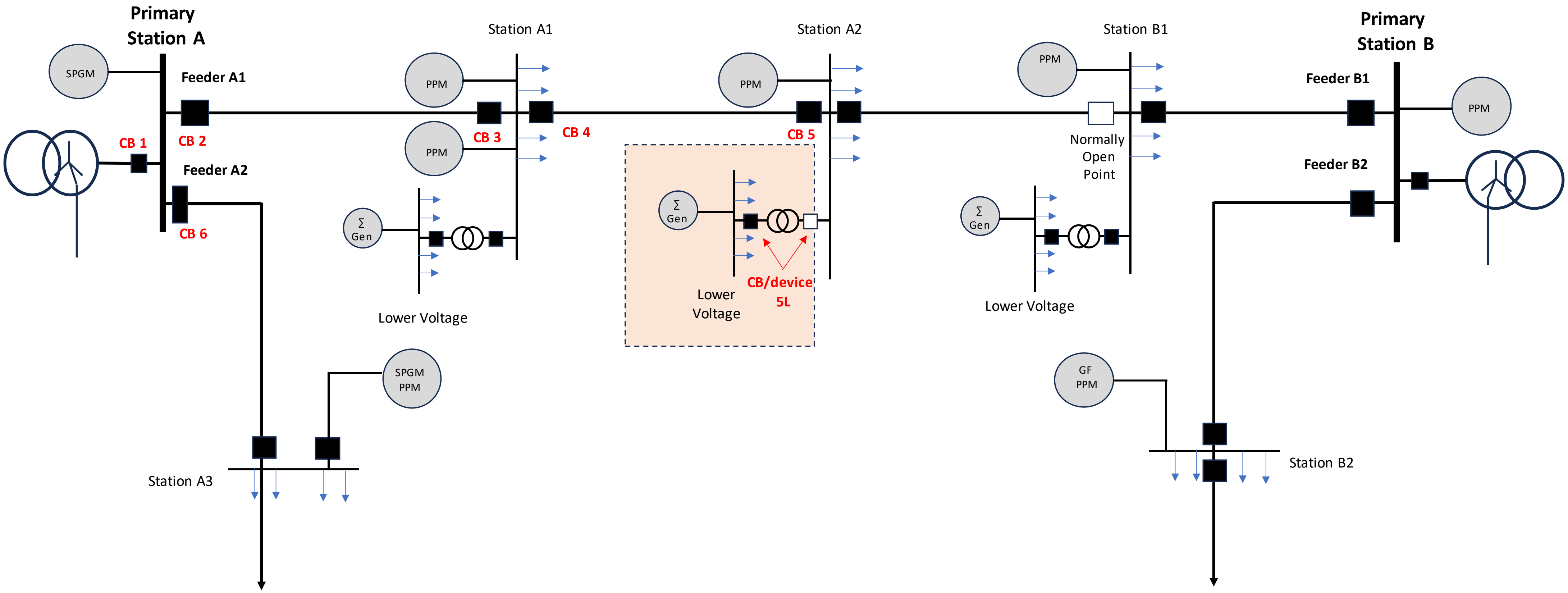

Figure 14: Island formed by opening CB/Device 5L

Primary Substation	Feeders	Secondary substations fed	Total Load [18] [MW]	Total Generation [MW]		
				Grid Following	Grid Forming	Synchronous PGMs
A	Busbar		0			9
	A1	A1	10	4	6	
		A1 lower voltage Busbar	3	0.5	4	1
		A2	8	7	1	
		A2 lower voltage Busbar	**4**	1	4	
	A3	A3	6	3		2
		Other stations not shown [Ax]	12	4	6	
	Total		4	1	4	11
B	Busbar		8	4	4	
	B1	B1	12	5	7	
		B1 lower voltage Busbar	2		5	
	B2	B2	6			11
		Other stations not shown [Bx]	14	4	9	
	Total		40	13	20	11

Table A. 15 - Scheme of description for assumed distribution network with generation and load – SCENARIO 4A

Total SPGM and GFC generation [MW]	5
Total trapped load [MW]	4
Generation/Load mis-match [%]	5/4 = 125%
Plausible risk of islanding	High – may need further specific analysis

Table A. 16 - Comparison of generation and load into the considered island – SCENARIO 4A

[18]Load on the island at the time under consideration.

Scenario 1B: CB 1 opens and LFDD is triggered

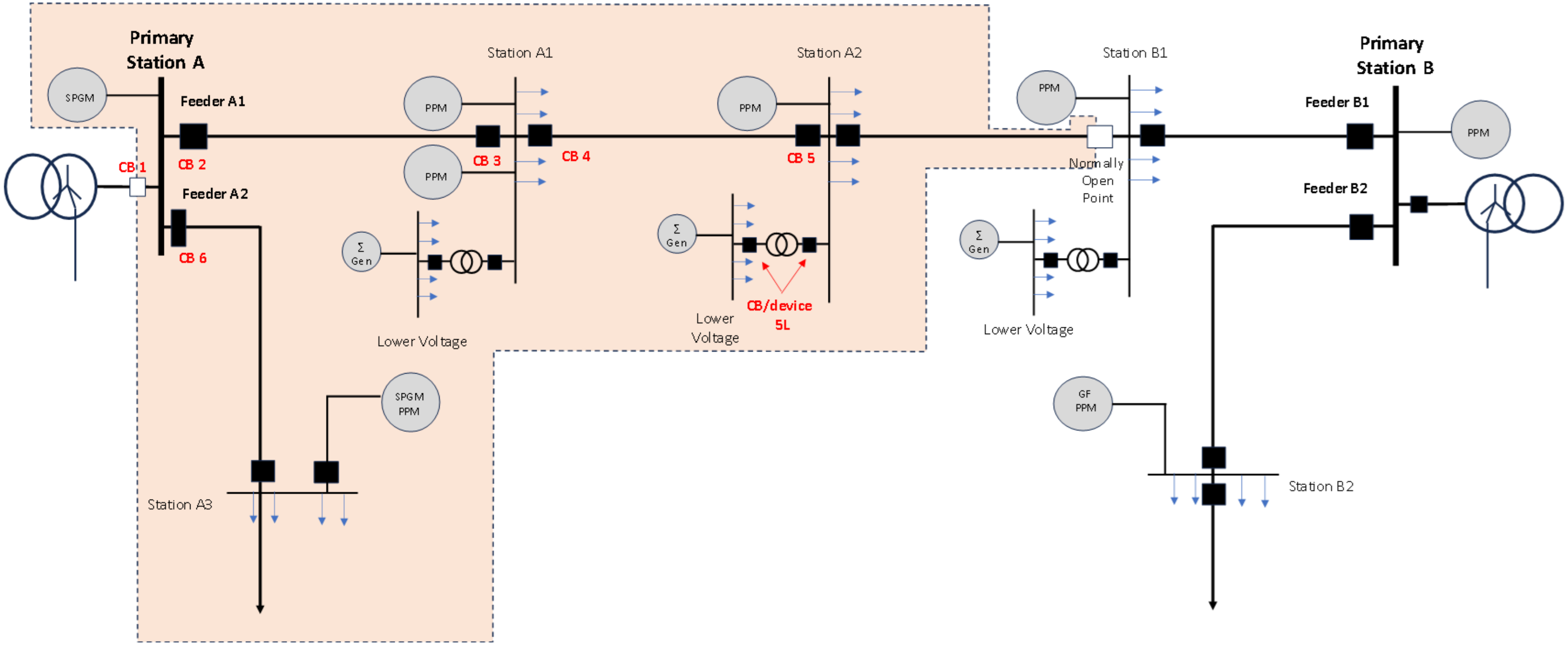

Figure 15: Island formed by opening CB1

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Primary Substation	Feeders	Secondary substations fed	Total Load[19] [MW]	LFDD load discon.	Total Generation [MW]		
					Grid Following	Grid Forming	Synchronous PGMs
A	Busbar		0	0	0	0	0
	A1	A1	10	0	4	0	
		A1 lower voltage Busbar	3	0	0.5	4	1
		A2	8	0	0	1	
		A2 lower voltage Busbar	4	0	1	4	
	A3	A3	6	6	3	1	2
		Other stations not shown [Ax]	12	12	4	0	
	Total		43	18	12.5	10	3
B	Busbar		8	0	4	4	
	B1	B1	12	0	5	7	
		B1 lower voltage Busbar	2	0		5	
	B2	B2	6	0			11
		Other stations not shown [Bx]	14	14	4	9	
	Total		40	14	13	20	11

Table A. 17 - Scheme of description for assumed distribution network with generation and load – SCENARIO 1B

Total summated generation [MW]	25,5
Total trapped load [MW]	43
LFDD Disconnected load [MW]	18
Generation/Load mis-match [%]	25.5/(43-18) = 102%
Plausible risk of islanding	High – may need further analysis

Table A. 18 - Comparison of generation and load into the considered island – SCENARIO 1B

Note that in this example if there was no LFDD the Generation/Load mismatch would be 59%, which would have placed it in the "low" islanding probability category. Due to LFDD load reduction the risk of islanding increased to 102%, placing in the "high – needs further analysis" category.

[19] Load on the island at the time under consideration.

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High Penetration illustrative scenarios: Geo-spatial representation of MV network

General

For MV networks in particular, practice varies among DSOs. All DSOs will have geographical mapping functions and system to record the physical routing of their networks. When it comes to switching operations and the maintenance of a real-time or dressed model of the state of the network, for HV networks the representations on the Operations Technology (OT) environment are almost exclusively in a schematic format as depicted in the sections above.

Some DSOs, for this purpose and for various other reasons, adopt a geographical representation of MV and/or LV network to guide switching activities. The section below is included for completeness, to reflect this practice, where it exists.

Sample MV Network

It is acknowledged that each DSO will have their own look and feel in terms of how such maps are depicted on their screens, and indeed different OT vendors will have their products look. The sample network is not meant to be definitive and is one of many possible representative samples.

- The MV feeders are mostly rural. There is a small amount of urban network not shown in detail (in another map).
- Blue = 10kV
- Red = 20kV

Two 20kV feeders are considered in this example. It is assumed that they are both fed from the same HV/20kV transformer.

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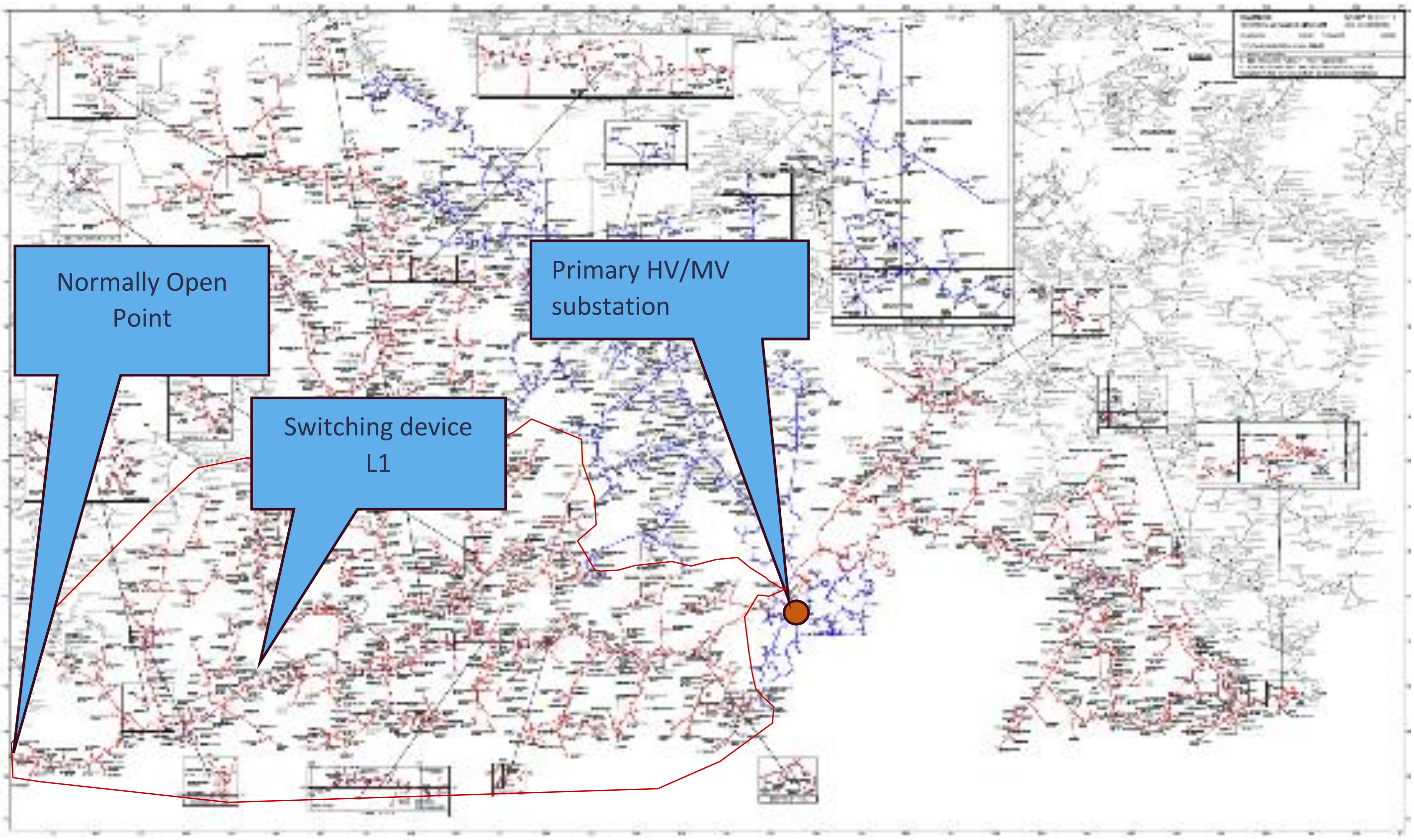

Figure 16: Geographical representation of two 20kV feeders

Primary Substation	Feeders	Network sections	Total Load [20] [MW]	Total Summated Generation [MW]		
				Grid Following	Grid Forming	Synchronous PGMs
HV/20kV transformer	20kV Busbar					
	Left feeder	Up to switching point L1	1.4	0.94	1.62	
		From L1 to Normally Open point	0.72	0.13	0.18	
	Right feeder	All	2.3	1.41	1.34	0.12
	Total		4.42	2.48	3.14	0.12

Table A. 19 - Scheme of description for assumed distribution network with generation and load

[20]Load on the island at the time under consideration.

Scenario 1G: HV/20kV transformer 20kV CB opens

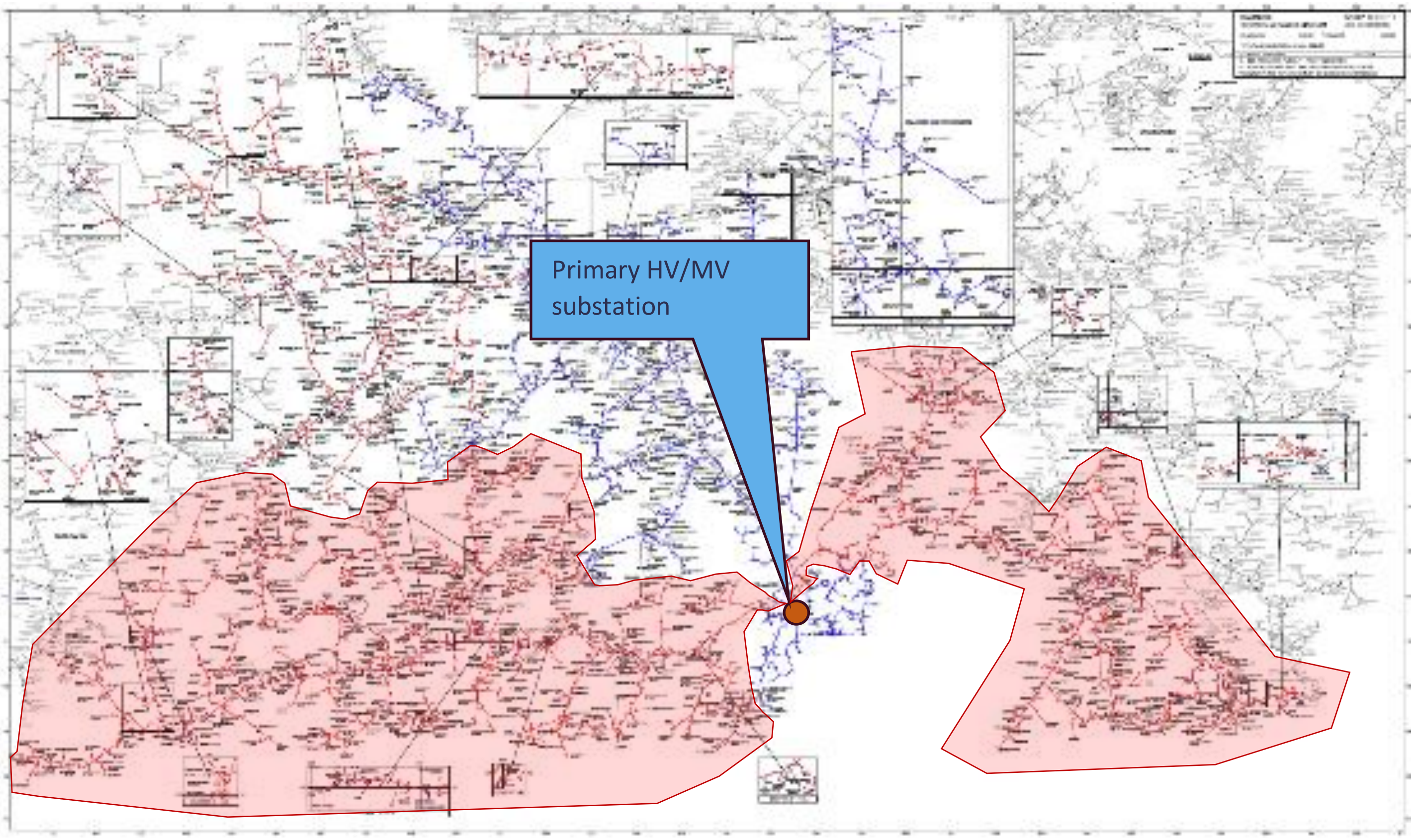

Figure 17: Geographical representation of island formed if 20kV HV/20kV transformer CB opens

Primary Substation	Feeders	Network sections	Total Load [21] [MW]	Total Summated Generation [MW]		
				Grid Following	Grid Forming	Synchronous PGMs
HV/20kV transformer	20kV Busbar					
	Left feeder	Up to switching point L1	1.4	0.94	1.62	
		From L1 to Normally Open point	0.72	0.13	0.18	
	Right feeder	All	2.3	1.41	1.34	0.12
	Total		4.42	2.48	3.14	0.12

Table A. 20 - Scheme of description for assumed distribution network with generation and load – Island scenario 1G

[21] Load on the island at the time under consideration.

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Total summated generation [MW]	5.74
Total trapped load [MW]	4.42
Generation/Load mis-match [%]	5.74 / 4.42 = 129
Plausible risk of islanding	High – may need further specific analysis

Table A. 21 - Comparison of generation and load into the sample islanded network – Island scenario 1G

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Scenario 2G: Left feeder 20kV CB opens

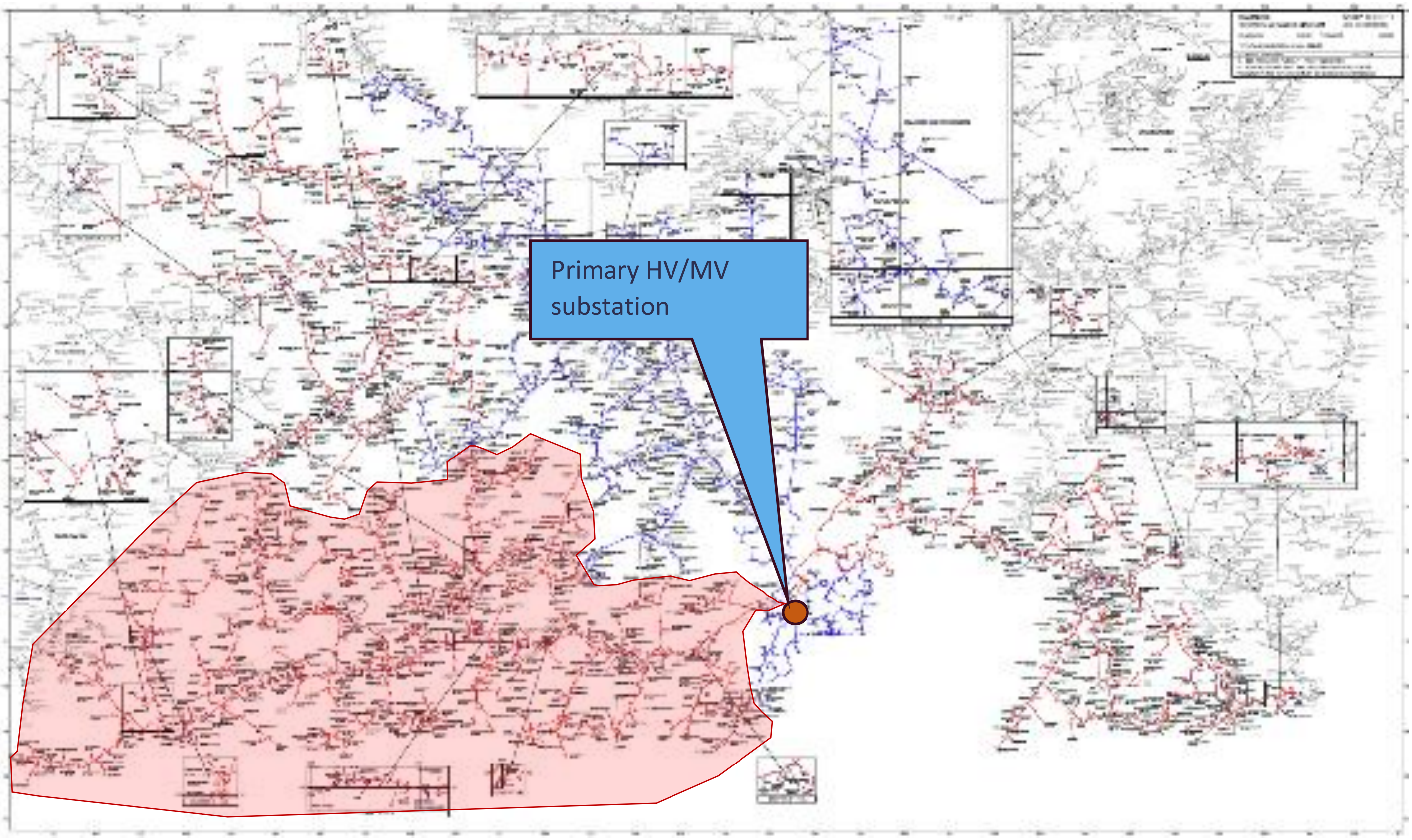

Figure 18: Island formed by opening of Left feeder CB

Primary Substation	Feeders	Network sections	Total Load [22] [MW]	Total Summated Generation [MW]		
				Grid Following	Grid Forming	Synchronous PGMs
HV/20kV transformer	20kV Busbar					
	Left feeder	Up to switching point L1	1.4	0.94	1.62	
		From L1 to Normally Open point	0.72	0.13	0.18	
	Right feeder	All	2.3	1.41	1.34	0.12
	Total		2.12	1.07	1.8	0.12

Table A. 22 - Scheme of description for assumed distribution network with generation and load – Island scenario 2G

[22]Load on the island at the time under consideration.

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Total summated generation [MW]	2.87
Total trapped load [MW]	2.12
Generation/Load mis-match [%]	2.87/2.12 = 135%
Plausible risk of islanding	High – may need further specific analysis

Table A. 23 - Comparison of generation and load into the sample islanded network – Island scenario 2G

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Scenario 3G: Switching device L1 on Left feeder opens

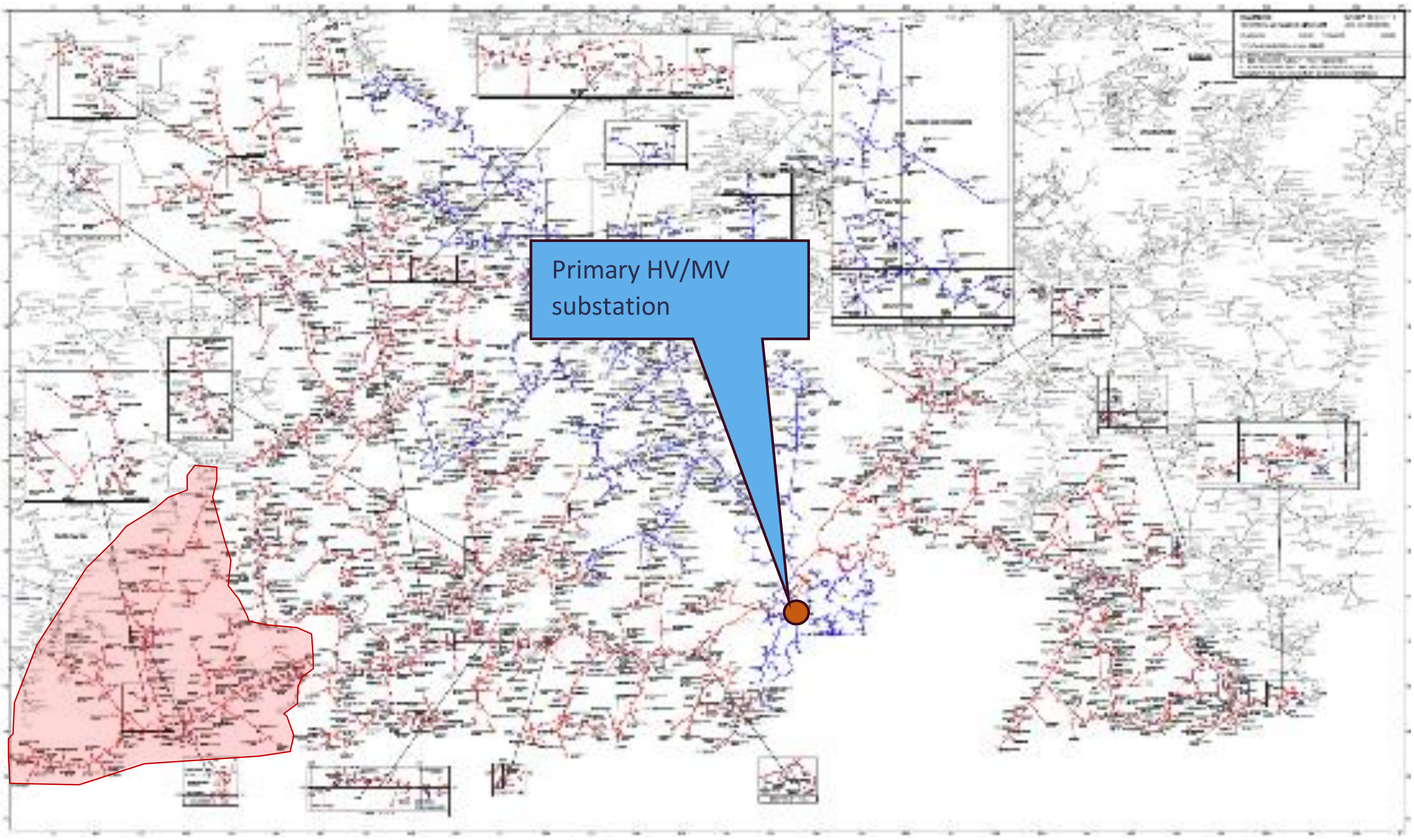

Figure 19: Island formed by opening of switching device L1 on Left feeder

Primary Substation	Feeders	Network sections	Total Load [23] [MW]	Total Summated Generation [MW]		
				Grid Following	Grid Forming	Synchronous PGMs
HV/20kV transformer	20kV Busbar					
	Left feeder	Up to switching point L1	1.4	0.94	1.62	
		From L1 to Normally Open point	0.72	0.13	0.18	
	Right feeder	All	2.3	1.41	1.34	0.12
	Total		0.72	0.13	0.18	0.12

Table A. 24 - Scheme of description for assumed distribution network with generation and load – Island scenario 3G

[23]Load on the island at the time under consideration.

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Total summated generation [MW]	0.31
Total trapped load [MW]	0.72
Generation/Load mis-match [%]	0.31/0.72 = 43%
Plausible risk of islanding	Low

Table A. 25 - Comparison of generation and load into the sample islanded network – Island scenario 3G

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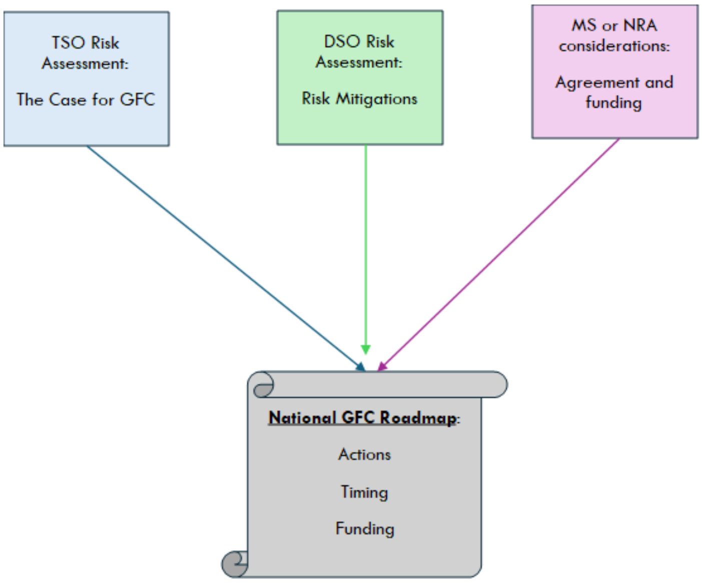
Appendix B: Assumed form of the national grid forming roadmap.

This skeleton document assumes the creation of a national roadmap using the process depicted below, and described in the Introduction to this document.



National GFC Roadmap Template

1 Scope and purpose

Short section stating the issues that are identified and resolved in this document, and its national status, governance etc

2 Background and development

Short description of the development of this document, including the analysis undertaken, its rigour etc, and support from stakeholders.

3 Identified risks

This section to be based on the analysis undertaken to develop the national roadmap

3.1 Whole system risks that grid forming mitigates

[TSO input – ie the light blue box from the diagram above]

3.2 Uncontrolled islands – Qualitative description of DSO issues arising

[DSO input - ie the green box above]

<u>3.2.1 Protection Operation</u>

<u>3.2.2 Interaction with other network equipment</u>

<u>3.2.3 Effect on quality of supply</u>

3.2.3.1 Voltage quality

3.2.3.2 Reliability/Interruptions

3.3 Stability

3.4 Other?

??

4 Quantitative and location specific analysis

[TSO and DSO input – ie from the blue and green boxes above, as appropriate]

More detail to be provided (and probably in appendices) of the risk analysis, matrices etc, broken down at an appropriate level of detail. This will also refer to Network Development Plans, as appropriate upon which the quantitative and locational analysis is based. This is where the main case should be further elaborated, by the TSO(s) for the introduction of grid forming. This document is probably going to be **the** formal record – so it will need to be comprehensive.

5 Mitigations

[DSO input - ie the green box above]

These might be best split into two simple classes as in this example, but other divisions of the mitigations might be more appropriate in some member states, eg by regulatory treatment.

5.1 Changes to Operational Practice

5.2 New/modified equipment and/or technologies

6 Regulatory considerations and outcomes

[NRA input – ie the pink box in the diagram above]

A statement of intent, ideally written by the NRA, on how regulation will support the implementation of the road map. This should also capture and be informed by, any agreed outcomes from tri-lateral discussions.

7 Future work

Including the revision of the road map, probably driven by both time, and also by events/developments.

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Appendix C: Breakdown of mitigation costs

	Item	Description	Price range		
			min	max	mean
Portugal	Earthing trafo and limiting reactance		€ 8,000	€ 21,000	€ 14,500
	Limiting Resistance		€ 6,000	€ 6,000	€ 6,000
	Substation adaption		€ 6,000	€ 6,000	€ 6,000
	V0> installation on a MV/LV Secondary Substation	Materials	€ 8,500	€ 8,500	€ 8,500
		Labour	€ 3,000	€ 3,000	€ 3,000
		Total	€ 31,500	€ 44,500	€ 38,000
Italy	Neutral Forming Transformer [NFT]	Earthing Trafo	€ 10,000	€ 10,000	€ 10,000
		Installation	€ 1,000	€ 15,000	€ 8,000
		Total			€ 18,000

Allowing for relatively low labour costs in Portugal, rounded figure of 50k is used.

Appendix D: Example of influence of LFDD in island rate of change of frequency

This appendix presents an analysis of a real-world event that aims to illustrate the effects of low-frequency demand disconnection (LFDD) on frequency behaviour during an islanding event. By analysing this case, we aim to enhance our understanding of the practical concerns and influence of underfrequency demand disconnection strategies in increasing the probability of island formation.

The temporary island event occurred in the MV level of a substation in Portugal. Figure D.1 illustrates the pre-fault load and generation within the MV network of the substation. The overall load was 2,71MW while the generation was 1,81MW. So, the initial mismatch is 67% (a medium probability island risk using the table 1 criterion).

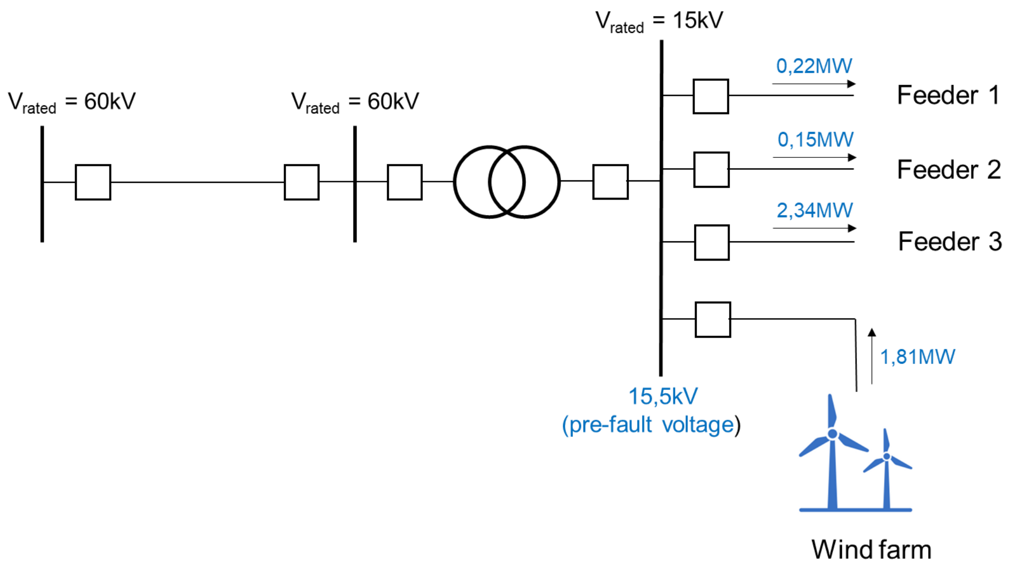

Figure D.1 – Pre-fault generation and feeder load

The incident started with an earth fault at the 60kV line that feeds the substation. Distance protection detected the fault and opened the circuit breaker at the far end of the line. However, the circuit breaker at the substation did not open because there is no communicating protection scheme in that line and the fault current coming from the substation was too small. After the 60kV circuit breaker opening the line's neutral passes to isolated, which causes the initial fault to self-extinguish. At this point the MV network is isolated from the rest of the grid (Figure D.2).

As indicated before, the network was importing power before the incident and, consequently, the frequency starts to steadily decrease after the island formation (Figure D.3). The load also decreases due to a decrease on the busbar voltage. When the frequency reaches 49Hz it triggers the two feeders which are part of the LFDD plan. This load removal causes the island generation to surpass the load in 0,1MW. Therefore, the frequency started to steady increase, thus inverting its trajectory (Figure D.3).

There was no further change to the load/generation and the frequency rose until it reached 51,5Hz at which point the over frequency interconnection protection tripped switching off the generation station and caused the island to collapse. It is worthwhile to mention that the wind farm was built before RfG was put into force in 2016 and does not comply with its requirement. Had it complied with the LFSM-O and FSM requirements, which lower the power injected into the network when an over frequency is present, the probability of the island remaining stable would have been much higher.

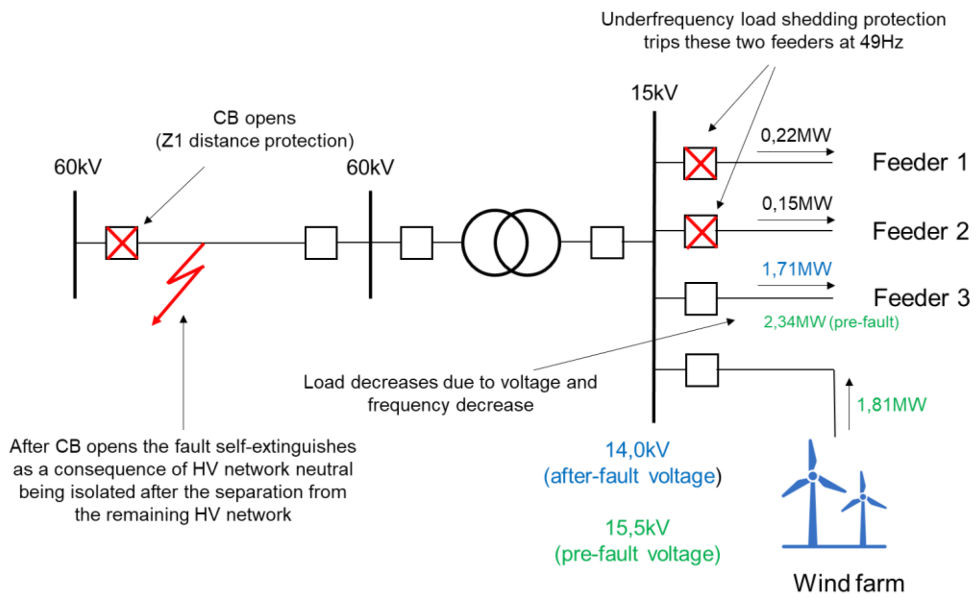

Figure D.2 – Island generation and load after the fault

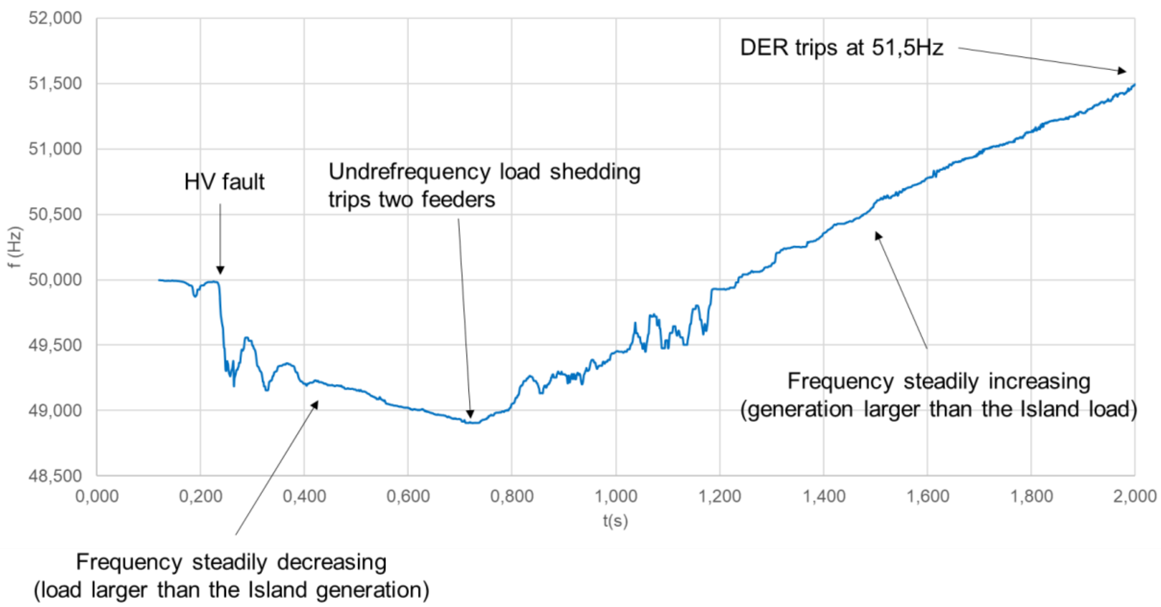

Figure D.3 – Frequency in the island during the incident

LFDD is a critical mechanism in power grids, designed to maintain stability and prevent widespread blackouts during frequency disturbances. Therefore, it is worthwhile mentioning that there is no intention to question its existence, nor FSM and LFSM. However, LFDDs effect on islanding forming probability must not be neglected.

During this incident the island's frequency was initially decreasing and the initial expectation was that it would reach the underfrequency interconnection protection setting clearing the island. However, LFDD changed the load/generation balance causing the frequency to increase and creating the conditions for a sustained island if the generation station had grid forming capabilities.