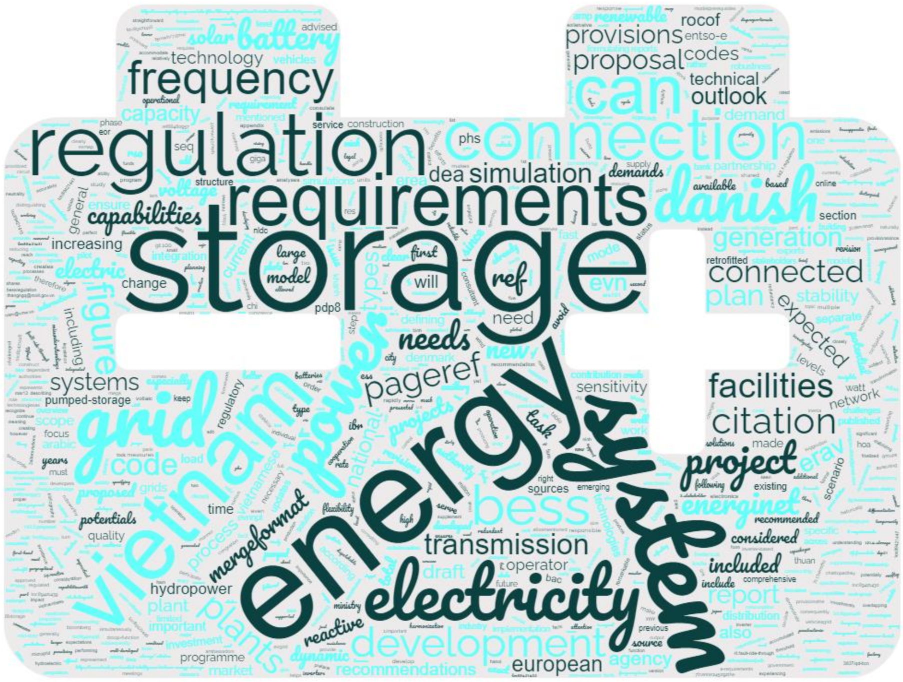
Formulating connection requirements for Battery Energy Storage Systems

A presentation and analysis of key functionalities to consider when formulating connection requirements for BESS to be connected the Vietnamese power system

16 August 2023



ERAV
Electricity Regulatory Authority of Vietnam

Danish Energy Agency

Disclaimer

This report is developed under the Vietnamese-Danish Energy Partnership Programme (DEPP3) by Electricity Regulatory Authority of Viet Nam (ERAV), Danish Energy Agency (DEA), and Energinet. It represents outcomes from the cooperation but does not represent the official position of ERAV.

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Abbreviations

AC - Alternating Current

BESS - Battery Energy Storage System

BMS - Battery Management System

CE - Central Europe

DC - Direct Current

DEA - Danish Energy Agency

DEPP III - Danish Energy Partnership Program III

EMT - Electro Magnetic Transient

EMS - Energy Management System

ENTSO-E - European Network of Transmission System Operators for Electricity

ERAV - Electricity Regulatory Authority of Vietnam

FRT - Fault Ride Through

GW - Gigawatt

Hz - Hertz

HVDC - High Voltage Direct Current

HVFRT - High Voltage Fault Ride Through

IEC - International Electrotechnical Commission

LFSM - Limited Frequency Sensitivity Mode

LFSM-O - Limited Frequency Sensitive Mode - Overfrequency

LFSM-U - Limited Frequency Sensitive Mode - Underfrequency

LVRT - Low Voltage Ride Through

LVFRT - Low Voltage Fault Ride Through

MW - Megawatt

MVAr - Mega Volt Ampere Reactive

NC RfG - Network Code: Requirements for Generators

NLDC - National Load Dispatch Centre

PCS - Power Conversion System

PBS - Power Converter Based System

PPMs - Power Producing Modules

RMS - Root Mean Square

RG-CE - System Protection & Dynamics Sub Group under the ENTSO-E

RoCoF - Rate of Change of Frequency

RE - Renewable Energy

SCADA - Supervisory Control and Data Acquisition

TSOs - Transmission System Operators)

VN - Vietnam

Introduction

The storage of electrical energy is a technology with increasing relevance in the green transition. The inherently flexible nature of power generated from wind and solar resources, can create a mismatch between generation and demand. These mismatches can be accommodated through storage technologies. With the rapid technological evolution, Battery Energy Storage Systems (BESS) can become an important building block of tomorrow's energy systems. BESS' ability to quickly change from generating- to consuming state and vice versa, can challenge the grid stability, if not regulated proper. Conversely can the BESS' abilities also be used in efforts to stabilize the power grid if the relevant system operator (RSO) has the right tools to control the BESS. Danish authorities have made valuable first-hand experience with one of the worlds' first connection requirements for BESS, these experiences have been shared during the course of 2022 under the Danish/Vietnamese Government to Government Programme: Danish Energy Partnership Program III. This report aims to document the work undertaken in aforementioned collaboration.

During previous collaboration[1] between Danish Energy Agency and ERAV, recommendations on where to focus the development of Vietnam's regulatory framework have been made. The recommendations were formulated as a 5 step approach and are presented in the Figure 1 below. As per the Figure 1, the development of a storage connection code is recommended, albeit first in step 3, but the previous recommendations are not a prerequisite for the development of a BESS connection code.

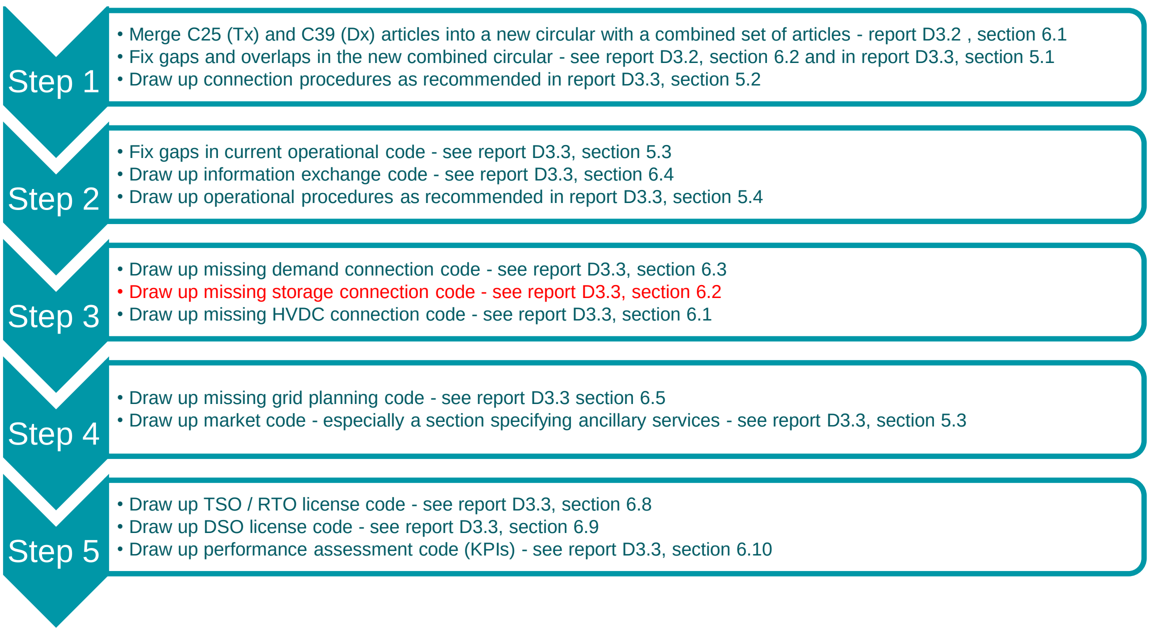

Figure 1 Five step approach

[1] DEPPII

1. Reading guide

The report provides an overview of the Vietnam energy system and explores the potential opportunities for integrating Battery Energy Storage Systems (BESS). It highlights the discussions and findings of the implementation group composed of experts from ERAV, EVN-NLDC, DEA, throughout 2022 and 2023.

The first sections sets the context for the Vietnam energy system, outlining its current state and the possibilities for incorporating BESS into the existing infrastructure. This section provides a background understanding of the energy landscape in Vietnam.

Discussions and Findings: The main body of the report documents the detailed discussions held by the implementation group. It highlights the key points, considerations, and recommendations derived from these discussions. The discussions cover a range of relevant topics related to the integration of BESS in the Vietnam energy system.

The attached Annexure 1 is a proposal for a Vietnamese connection requirement for BESS - This annexure presents a comprehensive proposal outlining the specific connection requirements for BESS in Vietnam.

It is emphasized that the content of the report does not encompass all requirements for BESS. However, it identifies the most prevalent topics and issues discussed by the implementation group. Importantly, it should be stressed that these requirements are also applicable to other inverter-based resources. The authors recommend a general update of Vietnam's complex of connection requirements, as per the previous Figure 1, drawing inspiration from the findings presented in the report.

2. Overview of Vietnam's Power System

2.1. Current status of Vietnam's power system

By 2021, the total installed capacity of Vietnam's power sources was about 78 GW, with an energy output of about 257 billion kWh, meeting more than 220 billion kWh of electricity demand of the whole system [1]. Hydropower sources had a total installed capacity of nearly 22 GW, concentrated in the mountainous areas of the Northwest, the West of the Annamite range (from Thanh Hoa to Quang Tri), the Central Highlands and the South Central region.

Coal-fired power sources with a total installed capacity of about 25 GW are concentrated mainly in the Northeast, Central Coast and the **South**. Gas turbine plants with a total installed capacity of about 7 GW are located near the southern coast, convenient for exploiting gas fields in the South East Sea.

Before 2019, Vietnam's power sources were mainly conventional power sources including coal-fired power, gas turbine, and hydropower. Since 2019, due to the Government's incentive mechanisms for renewable energy development, solar and wind power sources have experienced significant growth. By 2021, Vietnam's power system have had over 16 GW of solar power (including rooftop solar power) and 4 GW of wind power. The total capacity of these two sources currently accounts for about 26% of the installed capacity of the whole system.

Vietnam's power grid is divided into different voltage levels including the transmission grid at 500kV and 220kV and the distribution grid at 110kV, 35kV, 22kV and 0.4kV. Power sources can be connected to the national grid at all voltage levels from 500kV to 0.4kV. With the country's long and narrow terrain along the north-south direction, the main power sources located far from the load centers, the 500kV power grid plays an important role in the link between the three regions of the North - Central - South, as well as the inter-regional transmission within each region.

The 220kV power grid covers all 63 provinces and cities nationwide with over 19,000 km of transmission lines [1]. The 220kV power grid constitutes the transmission network within a region. The long-distance transmission role of the 220 kV power grid is only present in some areas including the Northern mountainous region and the Central Highlands.

The 110 kV grid is currently considered as a distribution grid, and is spread across the country with a total length of about 24,000 km [1]. The medium voltage power system in Vietnam is being defined as the voltage level from over 1kV to 35 kV. Low voltage level is smaller than or equal to 1kV. This is the power grid system that supplies electricity directly to the majority of customers. Previously, the medium-low voltage power system was built on the philosophy of one-way power supply: the state builds the power grid to supply electricity in a single direction. However, along with the trend of "greening" power sources, renewable energy sources such as solar power (especially rooftop solar power) emerge more and more, leading to the change of active power flow in the medium- and low voltage grid, from the customer's side to the power system, which can cause overload of medium- and low voltage lines.

2.2. Development potential of Vietnam's power system

Vietnam's power system is forecasted to continue to develop strongly in the future. According to the National Power Development Plan for the period of 2021-2030, with a vision to 2050 (PDP VIII), the national electricity demand in 2030 will be about 505 billion kWh. To meet the above electricity demand, about 150 GW_e production capacity is needed, with an energy output of about 567 billion kWh in 2030. From which, the total capacity of wind and solar power is expected to be nearly 41 GW, accounting for about 27% of the installed capacity of the whole system. In 2050, in order to ensure the Government's goal of neutralizing carbon emissions, the total installed capacity of these two types of sources can account for around 60% of the installed capacity of the whole system.

It can be seen that the penetration level in the power system of renewable energy sources such as wind power and solar power will increase. This causes many difficulties in planning and operation of the power system. Currently, Vietnam’s power system has been facing many problems in the operation of wind and solar power sources as follows:

- Local grid congestion on some segments of 500 kV line due to high generation of renewable energy sources.
- Forecast error of the generation of renewable energy sources causes difficulties in scheduling power plant mobilization.
- Voltage flicker, harmonics and the risk of power system instability.

In order to limit the negative effects from renewable energy sources in the power system, the use of energy storage systems, including battery storage, is considered as one of the most feasible solutions in the modern power system. According to the PDP VIII, Vietnam's power system needs about 2.7 GW of pumped storage hydropower sources and batteries (of which the capacity of batteries is about 0.3 GW) in 2030, and may need about 30-45 GW of these sources in 2050.

2.3. Current regulatory framework and prospects for new framework

2.3.1. Current regulations on the operation of Vietnam's power system

Currently, the regulations on the operation of the power system in Vietnam are stated in the following documents: Circular No. 25/2016/TT-BCT regulating the transmission power system, Circular No. 39/2015/TT-BCT regulating the distribution power system, Circular No. 30/2019/TT-BCT amending and supplementing a number of articles of Circular No. 25/2016/TT-BCT and Circular No. 39/2015/TT-BCT, and Circular No.39/2022/TT-BCT amending and supplementing a number of articles of the above Circulars. The main contents of Circular No. 25/2016/TT-BCT regulating the transmission power system, as amended according to Circular No. 30/2019/TT-BCT are as follows:

- Chapter I: General provisions, from Articles 1 to 3, provides the scope of regulation, the subjects of application and explains the definitions and technical terms shown in the Circular.
- Chapter II sets forth the requirements for operation of the transmission power system, including 10 articles, from Articles 4 to 15. The standards of basic operating parameters in Vietnam's power system are shown in this Chapter, including standards for frequency, voltage, voltage unbalance, harmonics, voltage flicker level, grounding, short circuit current and fault clearance time, earth fault factor, reliability and method of calculating energy loss on the transmission grid.
- Chapter III provides regulations and guidelines on the forecasting of electricity demand of the national power system, including 6 articles, from Article 16 to Article 21.
- Chapter IV on transmission grid development plan has been abolished according to Circular No. 30/2019/TT-BCT.
- Chapter V sets out regulations on Connection to the transmission grid, including 8 Sections, 33 Articles, from Articles 26 to 58. This is one of the two most important contents of Circular 25, helping to standardize the investment and development of the power grid, in order to build a unified and synchronous power system capable of smooth management, monitoring and control from dispatching centers. In addition, Chapter V also sets out specific connection requirements for some types of power sources such as hydropower plants, thermal power plants, wind power plants, and solar power plants. However, some types of power sources are likely to emerge in Vietnam such as pumped-storage hydroelectricity, BESS, Fly wheel, etc., which currently are not being regulated.
- Chapter VI sets out the regulations on the operation of the transmission power system, including 6 Sections, 33 Articles, from Article 59 to Article 91. This is the second important content of the Circular, helping stakeholders maintain the operation of the power system in a reliable, safe, proactive and efficient manner.
- Chapter VII regulates the security assessment of the power system, including 4 articles (from Articles 92 to 95), giving principles and requirements to ensure and maintain the power system operating with the necessary redundancy, are assessed daily, weekly, monthly, annually.
- The quality of transmission power system operation is specified in Chapter VIII including 3 Articles 96, 97, 98. The quality of transmission power system operation is expressed through quality indicators such as the number of times the frequency is out of the allowed range, grid availability, voltage deviation index, grid overload, power outage on the transmission system, etc. These indicators are the basis for assessing power transmission service quality and service quality improvement from time to time.

- Chapter IX provides for dispute settlement and handling of violations, including 2 Articles (99, 100), according to which disputes arising during the implementation of this Circular will be mutually agreed upon by the parties before submitting to the Electricity Regulatory Authority for settlement.
- Chapter X includes 2 Articles 101 and 102, providing solutions on the implementation of this Circular and regulations on the effective period of this Circular.

The main contents of Circular No. 39/2015/TT-BCT regulating the distribution power system, as amended according to Circular No. 30/2019/TT-BCT are as follows:

- Chapter I: General provisions, provides the scope of regulation, subjects of application, terms, definitions and concepts used in Circular 39. Many concepts and terms coincide with Circular No. 25/2016 /TT-BCT.
- Chapter II sets out the requirements for the operation of the distribution power system, including 3 Sections, 15 Articles (from Articles 4 to 17a), of which 6 are amended and supplemented according to Circular 30. Many basic regulations on Operating parameters shown in Chapter II have the same or similar regulations as Circular 25, such as regulations on Frequency, voltage, voltage unbalance, harmonics, voltage flicker, short circuit current, grounding, earth fault factor, etc. The requirements for quality measurement of the distribution power system are also expressed through sets of indicators for reliability, energy loss, customer service quality and regulations on information disclosure on distribution grid quality.
- Chapter III includes 4 Articles, setting out regulations on Load demand forecasting of the Distribution power system and responsibilities of related parties for load forecasting.
- Chapter IV stipulates the distribution grid development and investment plan, which has been abolished according to Circular No. 30/2019/TT-BCT.
- Chapter V: Connection to the distribution grid, is a particularly important chapter to connect new power plants, or new loads to the distribution grid. However, some types of power sources are likely to emerge in Vietnam, such as BESS, which are currently not regulated.
- Chapter VI: Operation of the Distribution Power System, includes 9 Sections with 38 Articles, providing regulations to maintain the distribution power system operating stably, reliably, efficiently and safely.
- Chapter VII provides solutions on the implementation of Circular 30 and regulations on the effective period of implementation.

2.3.2. The need to develop regulations on the operation of BESS in Vietnam's power system

As mentioned above, the demand for BESS in Vietnam's power system is expected to rise in order to meet the increasing penetration level of RE in the power system. Currently, there are no specific regulations on the operation of BESS in Vietnam's power system. By reviewing the current regulations, some regulations can be applied to the battery storage. However, it is required to develop new regulations and add some details to the existing regulations in order to match the operation of this type of source in the power system, creating a premise for the development of the battery storage in Vietnam.

In this report, the basic recommendations for the operation of the battery storage in the power system are summarized in Table 1 below, it will be presented to create a premise to develop regulations on battery storage in Vietnam.

Regulations	Circular	Note
Frequency range	Circular 25/2016/TT-BCT Circular 39/2015/TT-BCT	
Voltage range	Circular 39/2015/TT-BCT	
Rate of Change of Frequency (RoCoF)	Circular 39/2022/TT-BCT	
Automatic connection	Circular 30/2019/TT-BCT	
Automatic reconnection	Circular 30/2019/TT-BCT	
Ramping limit during automatic connection/reconnection	Circular 39/2022/TT-BCT	
Fault ride through	Circular 39/2022/TT-BCT	Proposing additional operation area in case of overvoltage
Phase swing/phase jumps	Circular 39/2022/TT-BCT	
Sym. faults/asym. faults - voltage assistance		New proposal
Post fault active power recovery	Circular 39/2022/TT-BCT	Proposing on control error and response time
Black start	Circular 25/2016/TT-BCT	
Island operation	Circular 30/2019/TT-BCT	
Automatic disconnection - high/low voltage disconnection		New proposal
Disconnection of load due to under frequency		New proposal
Active power control		New proposal
Limited Frequency Sensitive Mode at Overfrequency (LFSM-O)	Circular 39/2022/TT-BCT	Proposing additional frequency threshol, and control and response time
Limited Frequency Sensitive Mode at Underfrequency (LFSM-U)		New proposal
Frequency Sensitive Mode		New proposal
Frequency restoration control	Circular 25/2016/TT-BCT	
Reactive power capability	Circular 30/2019/TT-BCT	

Regulations	Circular	Note
Voltage control	Circular 39/2022/TT-BCT	Proposing control and response time
Reactive power control	Circular 39/2022/TT-BCT	Proposing control and response time
Power factor control	Circular 39/2022/TT-BCT	Proposing control and response time
DC content	Circular 39/2022/TT-BCT	
Voltage imbalance	Circular 30/2019/TT-BCT	
Current imbalance		New proposal
Voltage harmonics	Circular 30/2019/TT-BCT	
Voltage harmonics	Circular 30/2019/TT-BCT	
Voltage fluctuation	Circular 25/2016/TT-BCT	
Flicker	Circular 30/2019/TT-BCT	
Data communication	Circular 30/2019/TT-BCT	Proposing additional on lists of information signals
SCADA	Circular 30/2019/TT-BCT	
Protection	Circular 30/2019/TT-BCT	Recommend adding emergency power level control function

Table 1 Proposing regulations for the operation of the battery storage in the Vietnamese power system

3. Danish regulatory framework and current updates

3.1. Danish regulation on storage systems

Most of the regulation concerning the Danish power system is handled at the European level. This ensures aligned requirements and promotes fair competition within the European power system. However, individual countries have the ability to introduce additional regulations for issues not covered by European regulations.

This was the case in Denmark in 2015 when internal analyses conducted by the Danish Transmission System Operator (TSO), Energinet, revealed a rapid increase in distributed storage connected to rooftop solar plants. Recognizing the need to establish connection requirements for storage units before too many were connected and existing plants were retrofitted with batteries, Energinet took the initiative. In mid-2017, Energinet published the first Technical Regulation 3.3.1 (TR 3.3.1), which specifically addressed the connection requirements for battery storage.

At the time, it was considered a priority to swiftly establish requirements for batteries rather than developing more comprehensive regulations for all types of storage. Despite the urgency, the process took approximately 1½ years, spanning from mid-2015 to late 2016. This involved nine stakeholder meetings with the participation of 18 stakeholders in total, nine draft versions of the TR, and over 500 hours of work for Energinet.

3.2. Updates of the current regulation – two-way EV chargers

Denmark is currently witnessing a significant surge in the number of electric vehicles (EVs), gradually posing challenges for the electricity grid. The country has experienced an increase in both plug-in hybrid and purely electric vehicles, thanks to their growing popularity and affordability. To encourage EV adoption, Denmark has exempted them from registration fees and introduced tax reductions as incentives.

However, the current legislation only addresses one-way chargers and overlooks the inclusion of two-way chargers. As a result, two-way chargers can currently connect to the grid without Energinet being able to enforce performance requirements on these units. Therefore, Energinet has decided to update the technical regulation 3.3.1 to include two-way chargers.

One major challenge faced by Energinet is the Limited Frequency Sensitivity Mode (LFSM) due to the presence of two synchronous areas, DK1 and DK2, each with different activation thresholds and droop requirements. The issue arises when an EV is driven from one synchronous area to another, as there is currently no functionality for the EV to register and adapt to the synchronous area it enters. As LFSM is an autonomous functionality, activation occurs automatically when the frequency exceeds predefined thresholds.

In addition, new storage technologies are also showing potential profitability for grid connection. Compressed air storage has emerged as a viable solution where air is pressurized in large reservoirs during periods of low electricity prices and released through a turbine when prices are high. Another promising technology is molten salt storage, where electricity is used to heat up molten salt during low-price periods, and the stored heat is converted to steam to drive a steam turbine when electricity prices rise. In both cases, the installations are considered as synchronous generators, and administered as such. Energinet's focus as a system operator primarily lies in the functionality and operation of the generator rather than its specific components. Consequently, the requirements for these two technologies will be identical. However, Danish regulatory requirements necessitate a mention of these technologies in the connection code for them to be covered by regulation.

2. Basic requirements related to the operation of BESS in power systems

The following section presents key functionalities and requirements of battery energy storage systems. It covers essential components such as battery technology, power conversion systems and control features.

2.1. The basic structure of BESS

A BESS usually consists of the following main components:

- Battery system consists of batteries connected together to achieve the desired voltage and current value.
- Battery management system (BMS) is responsible for controlling the batteries to help them operate within the limits of voltage, current, temperature and state of charge.
- Power conversion system (PCS) includes inverters that are responsible for connecting the battery system and converting current from DC to AC.
- Energy management system (EMS) is responsible for monitoring and controlling the charging or discharging power of the BESS based on the command of the dispatching unit.

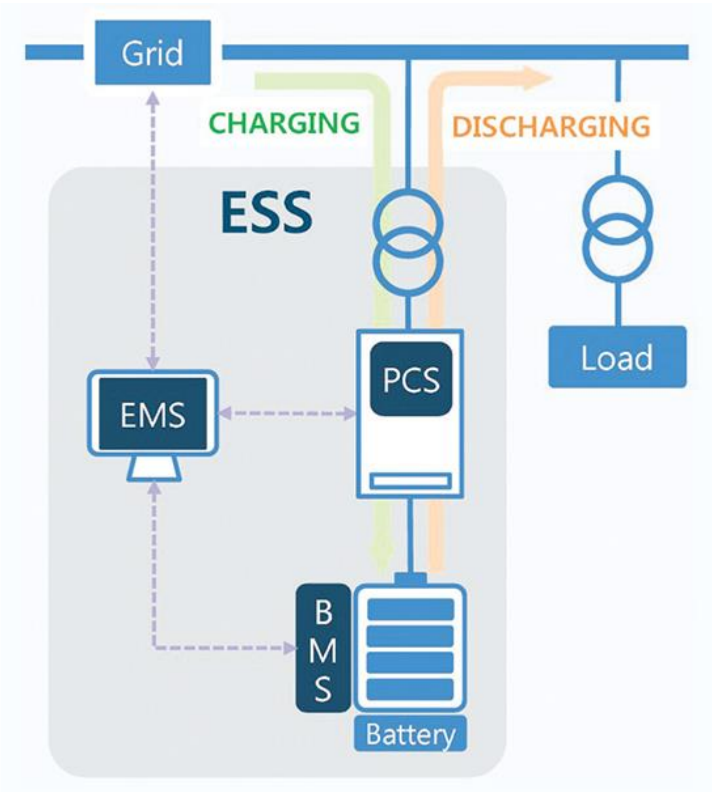

Figure 2 Illustration of the components of a BESS [2]

2.3. Basic requirements

BESS can operate in two modes: charging and discharging. In discharging mode, the BESS acts as a power source, in contrast, BESS acts like an electrical load in charging mode. Therefore, the operation of BESS in the power system needs to ensure basic regulations in both charging and discharging modes [3]. According to international experience, operative regulations for BESS are often built on the basis of existing grid operation regulations.

2.3.1. Frequency requirements

Similar to other types of power sources, a BESS is required to remain in operation for a period of time corresponding to the frequency ranges in the power system. The value of the allowed frequency range and operating time depends on factors including the characteristics of the power system, the capacity and technological characteristics of the battery, and the voltage level at the point of connection. BESS is usually required to operate continuously at a certain frequency range (often called the rated frequency range) and must operate for a finite period of time for frequencies outside the rated frequency range. Figure 3 illustrates the operating time requirements in the distribution grid, applicable to batteries with a capacity equal to or more than 3 MW in Denmark [4]. As can be seen, a BESS is required to operate continuously in the rated frequency range from 49 Hz to 51 Hz. In the frequency ranges of 51 – 51.5 Hz and 48.5 – 49 Hz, a BESS is required to operate for a minimum of 30 minutes, if the voltage is between 0.9-1.1 pu.

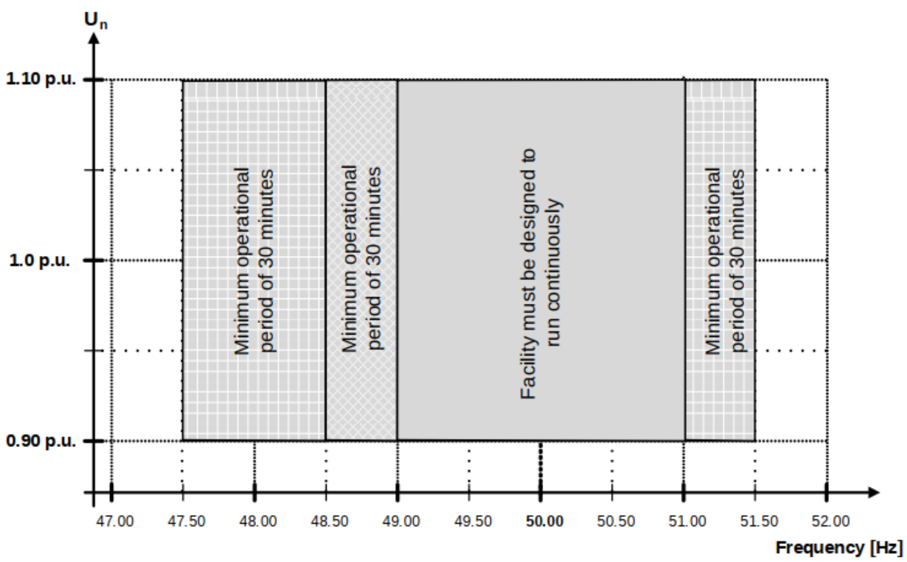

Figure 3 Operating time requirements across frequency ranges for BESS [4]

BESS is also required to maintain operation under certain rate of change of frequency (RoCoF). This is a new problem when power systems face more renewable energy sources and a reduced number of synchronous generators, as this reduces the system's inertia constant. Therefore, when there is an incident that reduces the active power (for example, a power plant trips and is disconnected), the frequency will collapse with a steeper slope and a faster reduction rate (large

RoCoF). A fast rate of frequency reduction makes it difficult to mobilize backup sources to restore the system frequency. RoCoF is used as an indicator to install anti-islanding mechanism, which can lead to disconnection of power supplies. Depending on the characteristics of the power system, each country has different regulations on the value of RoCoF applicable to the BESS. For example, in South Africa, BESS is required to keep operating with a value of RoCof = ±2,5Hz/s [5], this value is in some European countries ±2Hz/s [6].

In current grid operation regulations, BESS is often required to be able to increase or decrease active power output (even switching between modes when necessary can be required) in order to participate in underfrequency response (LFSM-U, limited frequency sensitive mode – underfrequency) or over-frequency response (LFSM-O, limited frequency sensitive mode – over-frequency) [4], [5], [7]. Participating in the frequency response of the BESS increases the power system's ability to keep frequency stable. Figure 4**Error! Reference source not found.** gives an example illustrating the active power control characteristics of a BESS in the frequency range [4]. In the f1-f2 frequency range, the BESS discharges a constant active power. If the frequency is less than the value f1, the BESS switches to underfrequency response mode, in order to increase the active power. If the frequency is greater than the value f2, the BESS switches to over-frequency response mode, in order to reduce the active power and hence perform over-frequency regulation the BESS can switch to the charging mode.

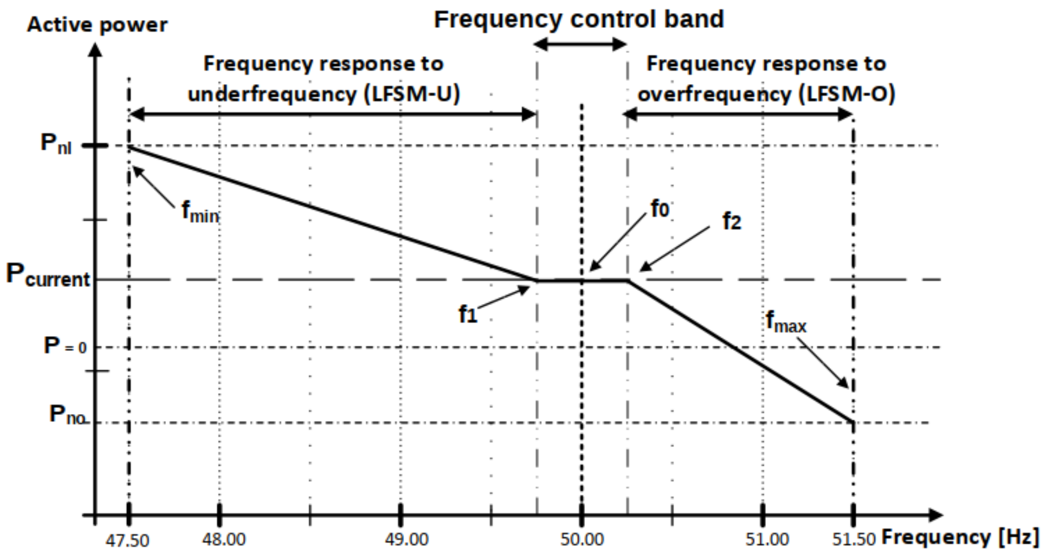

Figure 4 Active power control characteristics of a BESS in the frequency range [4]

In addition, the requirements for active power control of the BESS also include regulations on the maximum ramp rate to limit power fluctuations in the power system, and regulations on the minimum ramp rate to satisfy the power mobilization requirements of the dispatching unit.

2.3.2. Voltage requirements

Similar to the frequency requirements, the BESS is also required to remain in operation for a period corresponding to different voltages at the connection point. The value of the allowable voltage range and operating time depends on factors including the characteristics of the power system, the capacity and technological characteristics of the battery and connection voltage level. Figure 5 illustrates the operating time requirement in a 300-400 kV grid, applicable to batteries with a capacity equal or greater than 25 MW in Denmark [4]. As can be seen, a BESS is required to operate continuously in the rated voltage range of 0.9-1.05 pu. In 1.05-1.1 pu and 0.85-0.9 pu voltage ranges, a BESS is required to operate for a minimum of 60 minutes.

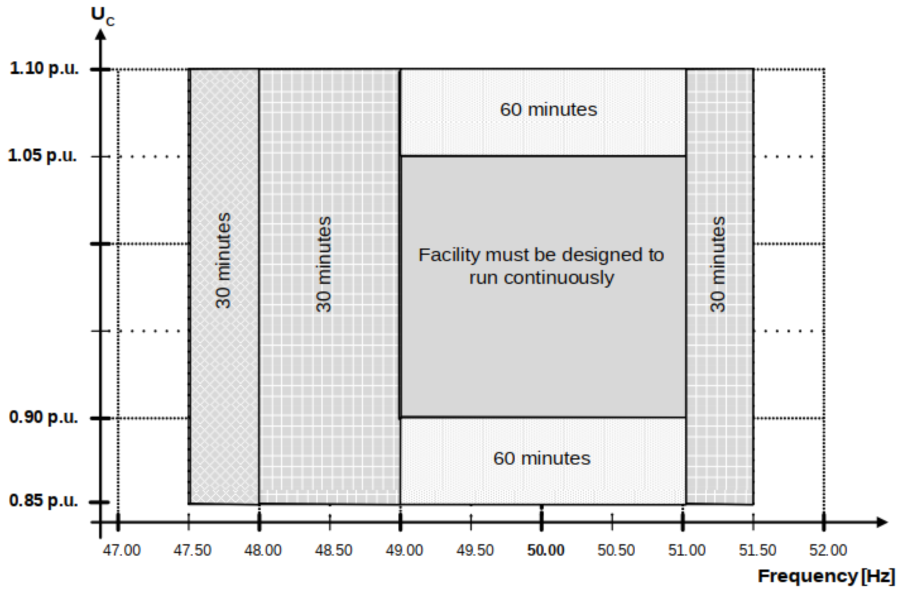

Figure 5 Operating time requirement across voltage ranges for a BESS [4]

BESS's are also required to maintain operation in the event of an incident causing low voltage in the power system (LVRT, Low voltage ride through) by generating reactive power, in order to maintain voltage stability in the power system [3]. Reactive power control methods include power factor control, voltage control, and independent reactive power control (Q control). Figure 6 illustrates an example of the LVRT characteristic of a BESS in the Danish transmission grid. When a short circuit occurs at the connection point, resulting in a voltage drop at the busbar to zero, a BESS needs to maintain operation for a minimum of 150 ms. and generate reactive power equal to the rated value.

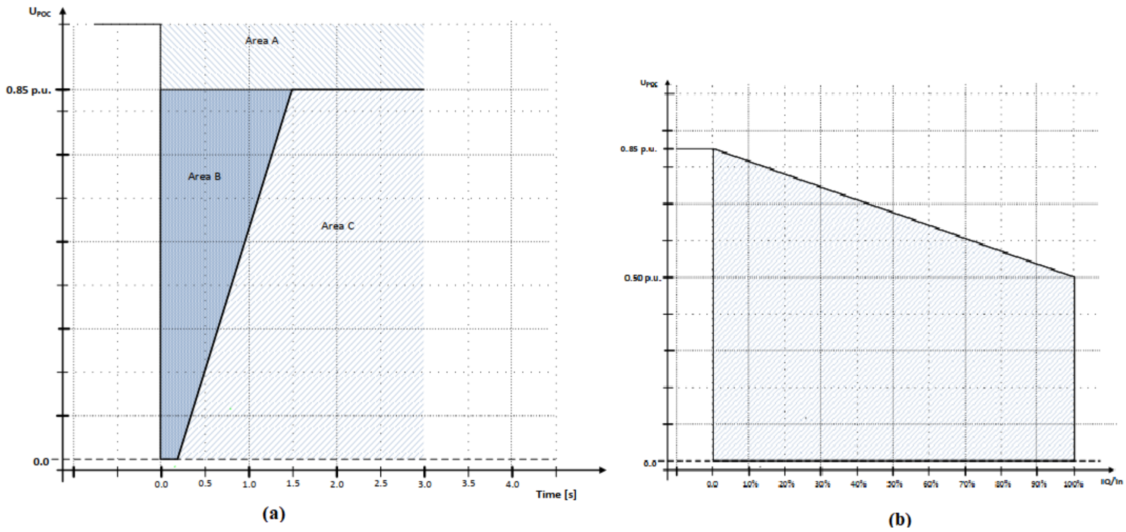

Figure 6 LVRT characteristic of a BESS in a transmission grid: (a) Voltage characteristic, (b) Reactive power characteristic

2.3.3. Other requirements

In addition to the basic requirements for frequency and voltage mentioned above, some requirements in the operation of the BESS include:

- Power quality: Because the BESS is connected to the power system through a power converter based system (PBS), there needs to be a requirement for the BESS for power quality issues such as harmonics, flicker and voltage unbalance.
- Protection system: BESS needs to be installed with relay systems to ensure the safe and stable operation of the power system.
- Monitoring system: BESS connected to the transmission grid are often required to connect to the SCADA system of the dispatching unit to facilitate monitoring, measurement and control, in order to comply with the control signal from the dispatching unit during the operation of the power system.

3. Defining design ranges for selected functionalities

The following chapter explains key functionalities that have been the subject of discussions between ERAV, DEA, and specialists from NLDC and Energinet during the course of 2022 and 2023. The functionalities are regarded as important for a safe and reliable power grid with a high share of inverter based resources. The functionalities must not be understood to be directly aimed at BESS, as these functionalities should be present in all units with an inverter-interface to the common grid.

3.1. RoCoF

The purpose of this section is to clarify which system stability indicators and data are applied in determination and justification of a reasonable value for the grid robustness requirement (connected units to stay connected) – RoCoF.

The following list comprises proposed simulations and observations for determining a reasonable RoCoF value for grid connected facilities to comply with. The justification includes, but is not limited to, the following steps:

1. Simulation of system separation or islanding scenarios, e.g. north – central and south
    a. What is the simulated df/dt in case of system separation scenarios?
    b. What is the simulated df/dt in case of loss of largest unit – (N-1) scenario?

2. Observed df/dt in case of system split and/or system incidences with islanding
    a. What is the maximum observed df/dt in case of islanding incidence?

3. Observed df/dt in case of intentional islanding
    a. What is the maximum observed df/dt / RoCoF values during intentional islanding?

4. Observed df/dt in case of system split and/or system incidences with islanding
    a. What is the observed df/dt in case of islanding incidence?

5. What is the estimated evolution of the generation and demand portfolio for the coming 3-5 years?
    a. How is the estimated balance between synchronous and non-synchronous generation in the portfolios?
    b. How is the evolution of the inverter based demand facilities (EV, robot based assembly plants (car, motorbikes), computer data centres etc. in the prognosis period?

Based on the findings, the maximum observed $RoCoF_{200}$ can be determined, with considerations about the estimated evolution of the portfolios.

The maximum average df/dt observed over 200 msec in case of system separation is 0.4-0.5 Hz/s, and the simulation study of islanding event with loss of 2000 MW will cause a RoCoF of around 0.5Hz/s, so a RoCoF value of 2.0 Hz/s is reasonable to secure that connected power plants are not tripping even in case of islanding / system separation events.

As the time window for averaging is essential for measuring and calculating the specified RoCoF value must have a subscript with the time period for averaging – an averaging period of 200 milliseconds is to be noted as $RoCoF_{200}$

The vast majority of commercially available power generating units are able to comply with the recommended 2.0 Hz/s value for $RoCoF_{200}$

3.3. Limited Frequency Sensitivity Mode

The frequency regulating control functions in the European power system are divided into the Frequency sensitivity mode (FSM) and the limited frequency sensitivity mode (LFSM). Both functionalities are activated via a droop control scheme.

The FSM control function is activated inside the frequency band for normal operation and is as such the control function that is activated when the power generating module some types of ancillary services, the procurement and dispatch of these reserves are based on a market mechanism. If the frequency moves outside the borders for normal operation, it can be assumed that all primary, secondary and tertiary reserves are exhausted and all power generation modules are required to activate LFSM control function, in this case the power market is deactivated. Plant owners are not required to reserve capacity for upregulation of active power under LFSM-U, the frequency regulation will in this case be carried out via down regulation of load. The plant owners are in cases of over frequency required to down-regulate their active power output to assist in adjusting the system frequency back inside the normal operation band. The following sections describes ENTSO-E's analysis and considerations when defining the maximum response time and droop settings for the LFSM functionality.

ENTSO-E assessed in 2016 that the frequency stability was not endangered during interconnected operation, even when the penetration of non-synchronous generation was very high [8]. The analysis was that only system splits could cause critical frequency deviations, which meant that only split scenarios were considered in the frequency stability evaluations.

The analysis consisted of an evaluation of the minimum inertia level in a given island after a system split as well as an evaluation of the effect of combinations of different droop settings and frequency activation thresholds with the purpose of defining the maximum response time in over-frequency regime to maintain frequency stability [8].

The primary focus of this chapter is to describe ENTSO-E's analysis when determining the requirements for generators, the evaluation of the minimum inertia level will only be discussed briefly, while evaluation of the maximum response time in over-frequency regime will be covered in more detail.

3.3.1. Evaluation of the minimum inertia

The following formula is used to determine the acceleration time constant [1]:

$$\text{Equation 1: } T_{N,min} = \frac{\Delta P_{Imbalance}}{P_{Load}} * \frac{f_0}{RoCoF_{max}}$$

If the two parameters $RoCoF_{max}$ and $\Delta P_{Imbalance}$ are fixed, then the minimum acceleration time constant of the network can be calculated. The purpose of the calculation is to determine the minimal amount of inertia needed to not violate maximum RoCoF limits at various levels of imbalances. Table 2 contains examples from the calculation, imbalances between 5 and 40% of the system load and RoCoF between 0.5 and 3 Hz/s are considered. The calculations assume a self-regulation of load of 2%/Hz [8].

$P_{imbalance}$ [%]	$RoCoF_{max}$ [Hz/s]	$T_{N,min}$ [s]
5	0.5	5.0
5	1	2.5
5	2	1.3
5	3	0.8
10	0.5	10.0
10	1	5.0
10	2	2.5
10	3	1.7
15	0.5	15.0
15	1	7.5
15	2	3.8
15	3	2.5
20	0.5	20.0
20	1	10.0
20	2	5.0
20	3	3.3
30	0.5	30.0
30	1	15.0
30	2	7.5
30	3	5.0
40	0.5	40.0
40	1	20.0
40	2	10.0
40	3	6.7

Table 2 Calculation of the minimum inertia. T_(N,min) is calculated from equation 1. [8]

If, for example, one region of the Central European (CE) synchronous area defines its maximum imbalance as 15% after a split and its maximum allowable RoCoF is defined to be 2 Hz/s, the minimum inertia of this region must be equal to an acceleration time constant of the network of $T_{N,min} = 3.8\ s$ to satisfy the maximum allowable RoCoF.

3.3.2. Evaluation of the maximum response time – over frequency

The response time for the activation of the Limited Frequency Sensitivity Mode can have severe impact on the functionality and accuracy of the LFSM, because of this the *RG-CE System Protection & Dynamics Sub Group* under the ENTSO-E made thorough analysis to assess the most optimal response time. The following section gives an account of the analysis and its results based on the report: *Frequency Stability Evaluation Criteria for the Synchronous Zone of Continental Europe* [8].

Model assumptions and inputs:

- All connected non-synchronous generation have an active power decrease response to over-frequencies. I.e. non-synchronous generation have the LFSM-O function in operation.
- The share of non-synchronous generation is at its maximum, corresponding to the lowest possible level of $T_{N,min}$ from Table 2.
- System Load: 220 GW and 440 GW
- The regulation is activated at different frequency thresholds (50.2 Hz, 50.3 Hz, 50.4 Hz and 50.5 Hz)
- Droop settings (%): 2, 5, 10 and 12
- RoCoF (Hz/s): 0.5, 1, 2 and 3
- Imbalance (% of system load): 5, 10, 15, 20, 30 and 40
- Synchronous operation point (%) 50, 75 and 100[2]

All 2304 combinations of the parameters were covered in the simulations. It should be noted that this simulation only focused on the first seconds after an event affected the frequency, where the RoCoF was the highest and the contribution from synchronous machines was limited to inertia – the governor response does not act until seconds after an incident [8].

As system splits are not predictable, the size of the islands and the amount of imbalance may vary considerably. In order to generalize the investigation, the imbalance is expressed as percentages of load in the island. This makes it possible to avoid looking at thousands of conceivable real system split scenarios [8].

3.3.3. Evaluation criterion of maximum response time

Defining the maximum response time required an evaluation criterion, meaning a standard factor to assess all the results. The step response shown in Figure 7 is a defined step in Δf_{max} the step can be regarded as a per unit value.

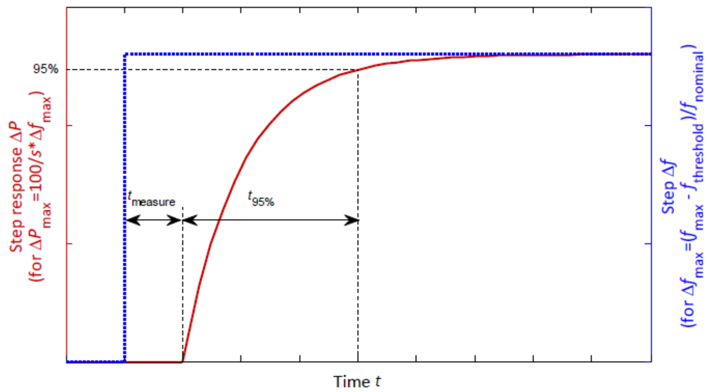

Figure 7 Evaluating the required time behavior of LFSM-O [8].

[2] This parameter denotes the sum of all synchronous generators' operating point. The parameter is inversely proportional with the level of inertia, as a lower synchronous operation point means more connected generators and hence higher level of inertia.

The value $t_{95\%}$ denotes the time it takes to activate 95% of the maximum achievable power frequency response. The time has to be short enough to contain the frequency inside the limit of 51.5 Hz [8].

One example scenario for the maximum response time calculation has the following parameters:

- System load: 440 GW
- Frequency threshold: 50.2 Hz
- Droop settings: 5%
- RoCoF: 3 Hz/s
- Imbalance: 30% of system load
- $T_{N,min}$: 5 s (resulting acceleration time constant from Figure)
- Synchronous operation point: 50%

Figure 8 depicts the frequency response from different maximum response times with above input parameters. As 51.5 Hz is the upper limit of the allowed frequency-band, the generators are allowed to disconnect immediately at this frequency. It is clear from Figure 8 that a response time of 2 seconds leads to an unacceptable violation of the frequency limit. The maximum response time needed to contain the frequency inside the acceptable range is found to be 1.38 seconds.

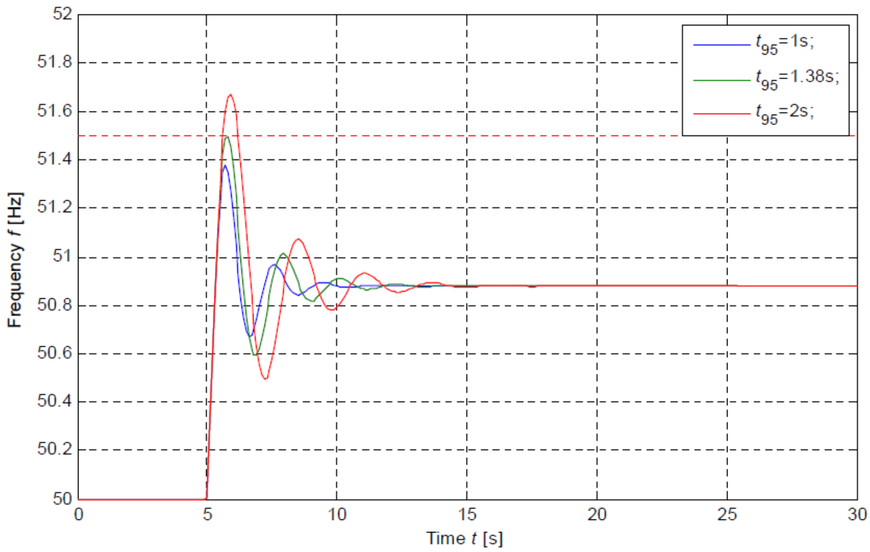

Figure 8 Time domain response for one exemplary scenario with different response times. [8]

According to the European Network Code: Requirements for Generators the droop is defined as [2]:

$$\textit{Equation 2: } s[\%] = 100 \cdot \frac{|\Delta f|-|\Delta f_1|}{f_n} \cdot \frac{P_{ref}}{|\Delta P|}$$

Isolating for $\frac{P_{ref}}{|\Delta P|}$ the equation can be rewritten as:

$$\textit{Equation 3: } \frac{P_{ref}}{|\Delta P|} = \frac{100}{s[\%]} \cdot \frac{|\Delta f|-|\Delta f_1|}{f_n}$$

And with the appropriate values inserted:

$$\textit{Equation 4: } \frac{P_{ref}}{|\Delta P|} = \frac{100}{5} \cdot \frac{51.5-50.2}{50} = 0.52$$

Meaning that in ≤1.38 seconds, 52% of the active power output of the non-synchronous generation will be reduced.

3.3.4. Results

The results from the study are shown in Figure . The different colours in each column represent different simulation results for each LFSM-O structure[3]:

- Orange colour: Number of simulations that have succeeded. Success is defined by: *not* exceeding the maximum RoCoF according to Error! Reference source not found.*and* by finding a maximum time limit for an activation of 95% of the down-regulation of the available capacity without exceeding the 51.5 Hz limit.
- Grey colour: The maximum RoCoF condition is violated
- Yellow colour: Simulations where the activation time for 95% of capacity is 0 and the 51.5 Hz. Limit is still exceeded.

The ENTSO-E report [8] does not elaborate on whether or not both fault conditions can be true for a simulation.

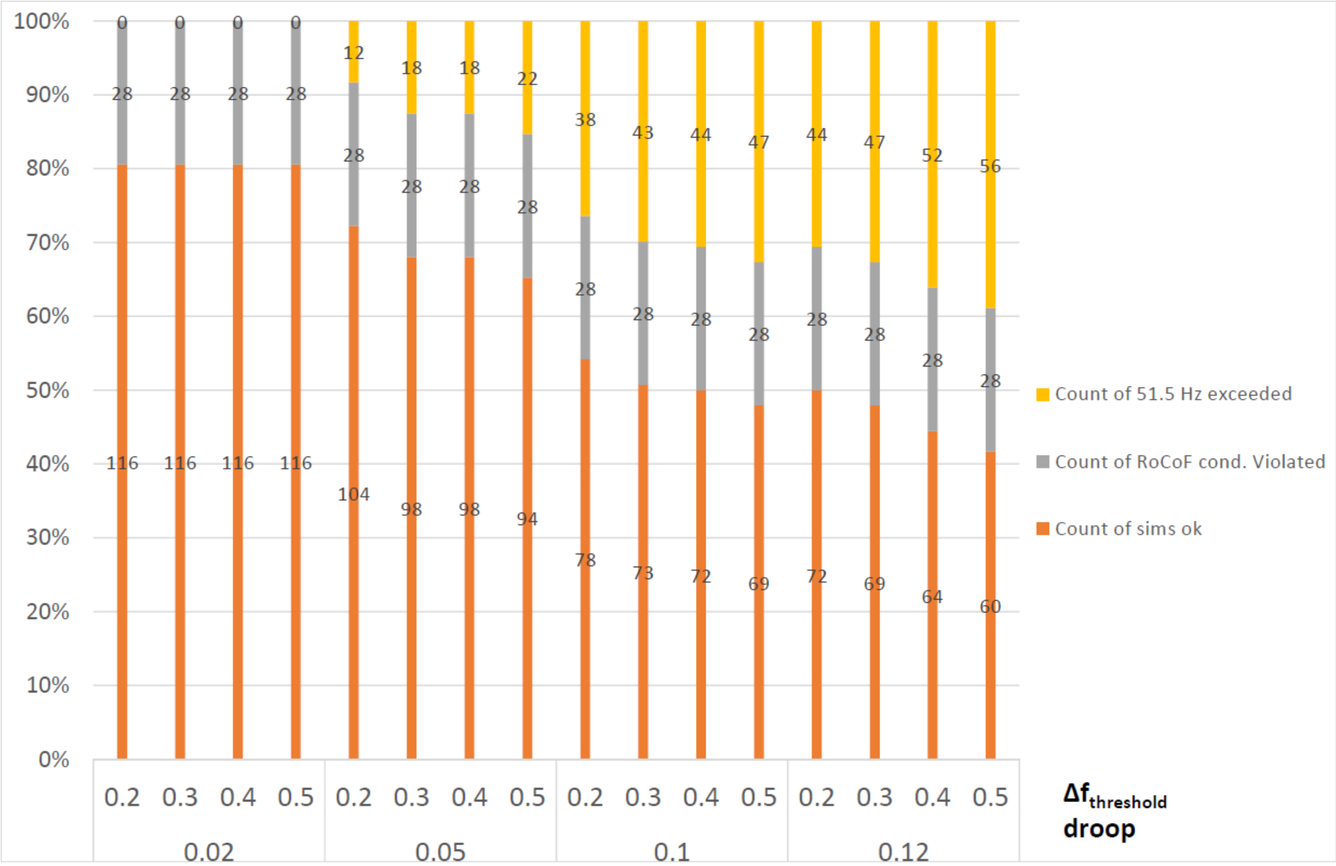

Figure 9 Simulation results for different frquency thresholds between 50.2 and 50.5 Hz and LFSM-O droop settings between 2% and 12% [8]

It is evident from the results depicted in Figure 9 that both droop and frequency threshold have an impact on the success of the simulations, but each settings impact is not visible from the plot, neither are the settings' impact on the time behaviour to reach a 95% activation. This information

[3] LFSM-O structure means a specific combination of droop setting and frequency threshold for activation

can however be found in the graph depicted in Figure 10. It can be observed in Figure 10 how the droop setting has a higher impact on the percentage of successful / stable scenarios.

The results in Figure 10 show that LFSM-O schemes with small droops and low frequency threshold provide the best results [8].

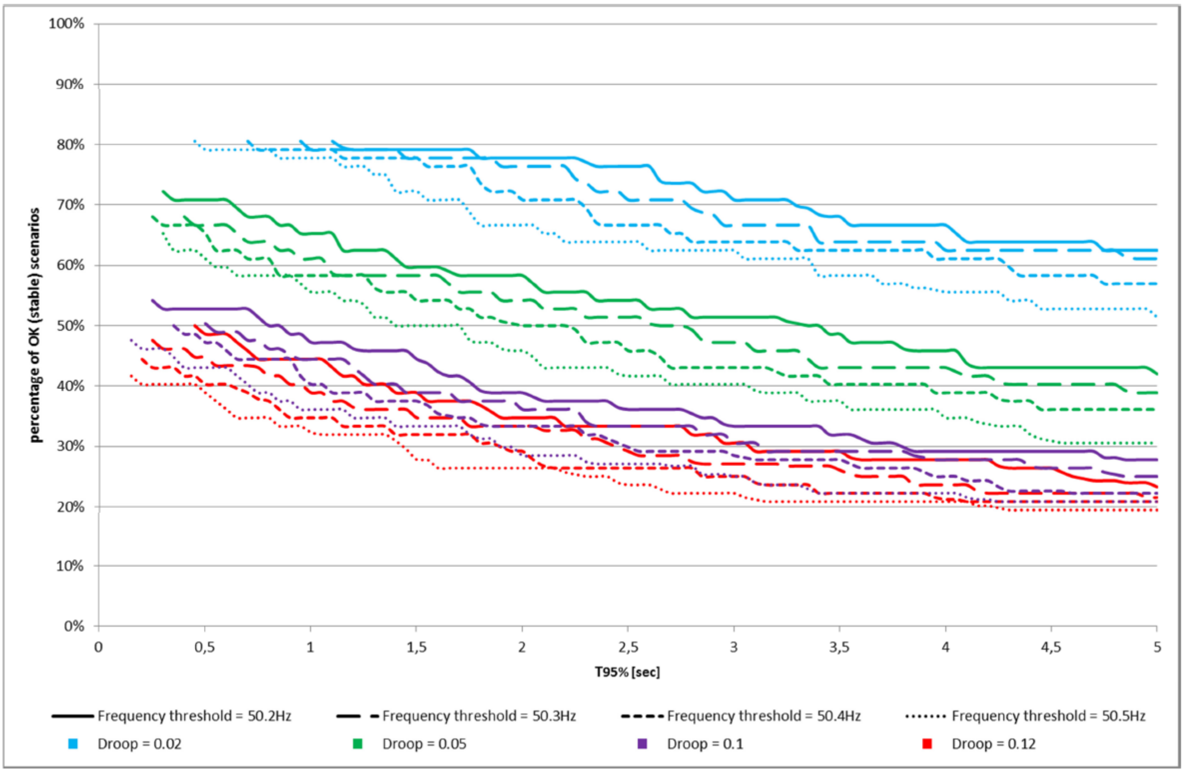

Figure 8 Percentage of stable scenarios depending on respond time and LFSM-O parameters

Figure 10 is a good tool for deciding on the maximum acceptable value of $t_{95\%}$; based on a compromise between the best results ($t_{95\%}$ close to 0s) and the different technology opportunities, mainly expressed by different combination of the key parameters. Taking all that into consideration, the authors of the report conclude that a value of $t_{95\%}$ < 1 s seems to be suitable with regard to withstanding a significant number of system split scenarios [8].

3.3.5. Conclusion and Recommendations

The main source of information for the previous chapter has the European Continent as the primary focus, however the conclusion and recommendations can still be of value for Vietnamese system operators and planners.

It should of course be evaluated first, if a system split is the most severe scenario also for the Vietnamese power system. If this is the case, evaluations of where the over-frequency and underfrequency islands will be formed should be considered. It can generally be stated that load shedding will be the primary tool for restoring the balance between load and demand in the underfrequency island. Load shedding requires a time delay in order to measure and detect the underfrequency and to open circuit breakers. Therefore, the success of load shedding depends on the rate of change of frequency in combination with the time delay of load shedding [8].

The situation for over-frequency regimes is however much different: here the LFSM-O function plays a crucial role. Three parameters are of particular interest:

- Rate of Change of Frequency = RoCoF
- Starting Frequency Point of the LFSM-O = 50.2 Hz or higher
- Speed of the power reduction = Droop

The requirement for each of these parameters for both synchronous areas in Denmark are listed in Table 3.

Parameter / Area	Frequency Threshold [Hz]	Droop [%]	RoCoF Threshold [Hz/s]
DK 1	50.2	5	2
DK 2	50.5	4	2

Table 3 Parameters for each synchronous area. DK1 is part of central European synchronous area, DK2 is connected to Nordic synchronous area

With a basis in previous consideration, calculation results and general power system dynamic principles, the following points are summarized: [8]

- Non-synchronous generation adapts its total power output to re-establish the load generation balance.
- By its inertia, the synchronous generation limits the RoCoF and provides therewith more time for restoring the equilibrium.
- Given a certain imbalance, the maximum possible power reduction is not sufficient if either the droop is not low enough to provide a high reduction of power output (according to the formula $\Delta P_{max} = \frac{100}{s} * \Delta f_{max}$) or the RoCoF is too high. In these cases, no stable state after a system split is possible, because the generation is always higher than the load.
- In the simulations it was assumed that all inertia is provided by synchronous generators. As a consequence, a minimum share of synchronous generation is required.

The ideas presented are based on a simplified model, which of course can provide some input and qualifications to a discussion about system stability, but other scenarios not modelled in the study can also become relevant. Therefore it should be considered to analyse the possible and permissible ratio between synchronous and non-synchronous generation with additional studies.

3.4. Fault Ride Through Capabillity

Fault Ride Through (FRT) is the capability for units to stay connected in case of a voltage failure. Activation of the FRT-capability can be caused by low voltage faults (LVFRT) or high voltage faults (HVFRT).

3.4.1. Proposed simulations and observations

The following is a list of simulations and observations for determining a reasonable FRT value for grid connected facilities to comply with:

1. Simulation of low and high voltage incidences
    a. What is the simulated maximum / critical fault clearing time in case of various short circuit scenarios? One phase; two phase; three phase faults?
2. Observed relay re-closure time in case of short circuit failures
    a. What is the maximum observed protection re-closure time in case of short circuits incidences on the various voltage levels? One phase; two phase; three phase faults?
    b. The internal protection relay setting must allow the FRT function to act.
3. What is the estimated evolution of the generation and demand portfolio for the coming 3-5 years?
    a. How is the current balance and the estimated balance 3-5 years ahead between synchronous and non-synchronous generation in the portfolios?
    b. What are the current requirements to the current generation and demand portfolio? Synchronous as well as non-synchronous resources?
    c. How is the evolution of the inverter based demand facilities (EV, robot based assembly plants (car, motorbikes), computer data centers etc.) in the prognosis period?
    d. Changes in the system characteristics such as network topology and whether priority are given to pre-fault operating conditions of power-generating modules or to longer fault clearance times.

3.4.2. Selecting the FRT-value

Based on the findings, select the FRT value as the double time of the critical fault clearing time taking into consideration the generation / demand portfolio technology and estimated evolution of the portfolios.

The diagram below in Figure 12 represents the lower limit of a voltage-against-time profile of the voltage at the connection point, expressed as the ratio of its actual value and its reference 1 p.u. value before, during and after a fault. The parameters are the following:

The specification of the FRT requirements include the following set of parameters:

- U_{ret} is the retained voltage at the connection point during a fault,
- U_{clear} is the retained voltage at the connection point when the fault is cleared,
- t_{clear} is the instant when the fault has been cleared,
- U_{rec1}, U_{rec2}, t_{rec1}, t_{rec2} and t_{rec3} specify certain points of lower limits of voltage.

It is recommended that the VN grid code specify the above listed set of parameters as table values, as illustrated in EU network codes for all generators - EU NC RfG table 3.1 and 3.2 below.

Fault-ride-through profile of a power-generating module

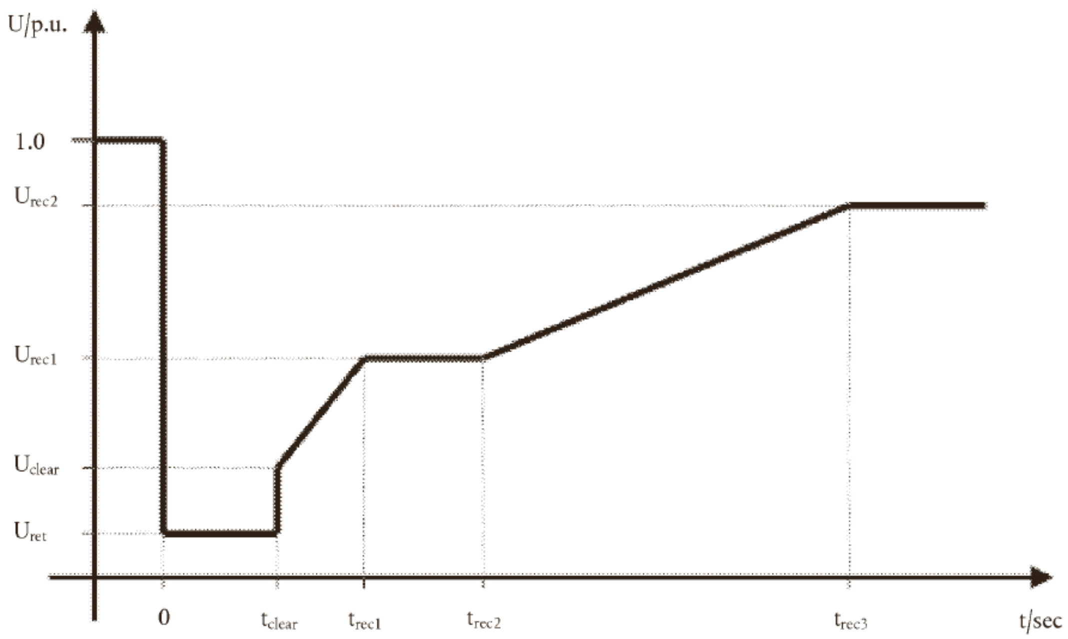

Figure 9 FRT limits

For synchronous generators, an LVFRT withstand time of 150 msec is reasonable to verify that connected power plants are not tripping in case of voltage dips at the PoC. Concerning an HVFRT, there is not such a specification in EU network codes. Individual EU member states may specify

Parameters for Figure 3 for fault-ride-through capability of power park modules

Voltage parameters (pu)		Time parameters (seconds)	
U_{ret}:	0,05-0,15	t_{clear}:	0,14-0,15 (or 0,14-0,25 if system protection and secure operation so require)
U_{clear}:	U_{ret}-0,15	t_{rec1}:	t_{clear}
U_{rec1}:	U_{clear}	t_{rec2}:	t_{rec1}
U_{rec2}:	0,85	t_{rec3}:	1,5-3,0

Table 3 Parameters specification for FRT limits

that on a national basis. Examples of LVFRT parameter specifications for non-synchronous generators from the EU NC RfG are reported below.

Examples of LVFRT parameter specifications for synchronous generators from EU NC RfG:

Parameters for Figure 3 for fault-ride-through capability of synchronous power-generating modules

Voltage parameters (pu)		Time parameters (seconds)	
U_{ret}:	0,05-0,3	t_{clear}:	0,14-0,15 (or 0,14-0,25 if system protection and secure operation so require)
U_{clear}:	0,7-0,9	t_{rec1}:	t_{clear}
U_{rec1}:	U_{clear}	t_{rec2}:	t_{rec1}-0,7
U_{rec2}:	0,85-0,9 and ≥ U_{clear}	t_{rec3}:	t_{rec2}-1,5

Table 4 Parameter specification for FRT limits

The majority of commercially available power generating units are able to comply with the recommended parameters for LVFRT.

Further details can be found in the EU NC RfG 613/2016, article 14, 16, 17, 20 and 21.

3.5. Fast Fault Current

The following section gives an introduction to the requirement: fast fault current, which is a requirement for inverters to inject reactive current during voltage dips. The requirement should be enforced on all types of inverter based generation, and not only BESS, but when ERAV wish to formulate requirements for BESS it is recommended to include provisions for fast fault current.

3.5.1. Introduction

Conventional generation is increasingly being replaced by inverter based generation, as a result of this, the total contribution to system faults will decrease further with voltage sensitivity rising. Reactive current injection during faults, helps to both recover the voltage during faults and to inject enough current quickly for system protective functions to operate reliably. Both of these aspects are related to the fault-ride-through family of requirements that are essential to wider system stability. The reactive current injection is denoted fast fault current (FFC) in the NC RfG. Type B plants and above shall be capable of providing FFC. [9]

The aim of the following section is to give a brief introduction to the topic of FFC and the considerations made by European regulators when introducing requirements for it. The basis of the chapter is the Implementation Guidance Document: *Fault Current Contribution from PPMs & HVDC* [9].

FFC is declared in the network codes: requirements for generators (NC RfG) and for High Voltage Direct Current (NC HVDC). The nature of the requirements is visible in below table.

Network Code: Requirements for Generators	Network Code: High Voltage Direct Current
TSOs have to specify what the requirements are for the plants' reaction both during and immediately after the fault	If specified by the relevant TSO, the HVDC shall have the capability to provide fast fault current

Table 5 NC RfG and NC HVDC provisions

3.5.2. Electrical faults and fast fault current

This section gives a short introduction to electrical faults and their relation to FFC, the intent is to explain the basic components for persons with a limited knowledge of electrical engineering.

Electrical faults in a power system occurs either as phase to phase faults or phase to ground faults. The faults can either be symmetrical, meaning that all three phases are affected, or asymmetrical, meaning that one or two phases are affected. The consequence of an electrical fault is the following:

1. The electrical resistance to the fault decreases
2. The voltage decreases very fast, it drops
3. The current increases very fast, it surges

As electrical faults are extremely harmful for equipment and potentially human life, the line on which they occur must be de-energized as fast as possible, this is done by opening circuit breakers in the nearest substation, the protective relays react on the current surge caused by the electrical fault and open the circuit breaker so the line is de-energized, the current needs to be of a certain magnitude for the relay to detect it.

The voltage drop caused by the fault is inherently a local issue but it can however affect the voltage in the vicinity at a scale large enough for generators to trip and hence create an unwanted cascading situation, to avoid this, the voltage must be supported during faults.

The FFC-functionality have an important purpose with regards to both aspects mentioned above:

1. Increasing the current during fault, so the protective relay can detect the fault.
2. Support the voltage to avoid cascading effects.

3.5.3. Three stages of the faults

The previously mentioned two objectives of the FFC each have a timeframe in which their purpose is the highest priority. The time period for current injection can generally speaking be divided into three parts [9]:

A. Immediately after the fault, while the main transmission system protections are measuring, e.g. 0-40ms.
B. The remaining part of the fault duration until fault clearance.
C. Immediately following fault clearance.

During **part A** the foremost transmission system objective is to ensure an adequate current for the protective relays to detect the fault and trigger an opening of the circuit breakers. For **part B** the foremost transmission system objective is to boost the voltage as much as possible to aid the generator stability. In both periods is a high magnitude rather than meeting an exact value regarded as the most favorable solution, with the reservation that the voltage should not in any instance exceed the normal voltage level. For **part C** the foremost objective in large systems with substantial inertia levels is to restore the system voltage towards the target voltage, limiting the voltage target overshoot and achieve a short settling time.

3.5.4. Technology Considerations

The reactive current contribution during faults is an inherent feature in the synchronous generators, hence the inverter based generators are the single objective when defining parameters for fast fault current.

Most inverter based generators are equipped with a full scale converter, meaning that there is a complete electrical separation between the DC-power source and the grid, however, wind turbines of the doubly fed induction generator (DFIG) type have the stator winding connected to the grid. By nature of this connection, a voltage dip will automatically cause a reactive current injection without delay, the amplitude depends on the generator characteristics and will decline within a few hundred milliseconds [9]. The support to the grid is shorter for DFIG-type wind generators than for synchronous generators and approximates to 50 milliseconds.

Lastly it can be mentioned how the specification of the FFC is implemented with a reference to positive sequence values. The wind industry in Europe have argued that the requirements excluded implementation of controlled actions in less than 20 milliseconds, and as such is a further time for initiation of control action and resulting WPP response needed to be allowed as well. [9]

3.5.5. Considerations for network topologies

A fast fault current contribution from non-synchronous generation located downstream of a fault on a radial network, may have two unwanted consequences.

1. The fault current contribution of the non-synchronous generation can reduce the resulting fault current to a magnitude which the protection devices will not recognize.
2. Fault current contribution from downstream parts of the circuit breaker may lead to delayed fault clearing since the fault current may maintain the fault.

Generally is the nature and scale of the complications associated with short circuit current contribution provided by PE pending greatly on the location of the short circuit as well as the characteristic of the local grid, e.g on- or offshore grid, long or short AC connections, and the generation/consumption balance of the relevant network section [9].

Ideally all of the above considerations should be duly evaluated when designing each network area and detailed variation of fault current contribution could be necessary for an optimal operation, but the authors of the main source of inspiration for this chapter [9] discusses the feasibility and practicality of such fine tuning of requirements. Engineering resources of mainly DSO's, and to some extent TSO's, can be a too much of a limiting factor for that to become feasible.

3.5.6. Summary: aspects to consider for fast fault current contribution

The aspects to consider when designing FFC-contribution requirements can be summarized in the below section. Two of the four aspects have been discussed in this note.

Aspects to consider:

1. *Priority between active and reactive current*

As the inverter is not able to both supply maximum available active and reactive current simultaneously due considerations as to whether the frequency or voltage stability respectively is of highest priority.

2. *Different needs in different time periods of the fault, taking the grid topology into action.*

The European experience here is that the challenge of finding suitable compromises between adequately covering the system needs today and into the future is best overcome by detailed attention to three separate time periods:

A. First part of the fault: Ensure adequate fault current for transmission system protections

B. Remainder duration of the fault: Support system voltage at locations away from the fault

C. Post fault clearance: Return system voltage towards normal range and support power recovery

During time period A and B the priority should be clearly set on the minimum time delay and maximum magnitude for fast fault current contribution while accuracy of the current angle is subordinate. The above is valid for meshed grids, radial networks may require that the FFC-contribution should be as low as technically possible in order to clear the fault. [9]

3. Need for asymmetric contribution

Requiring asymmetric reactive current is optional in the European legislation, but it is highly recommended for systems with a noticeable non-synchronous generation. Feeding symmetrical fault current to unsymmetrical faults could result in too high voltages on the healthy phases.

4. Consideration of technological characteristics

All full scaled converters, have similar capabilities in principle. Requirements for the smallest units should be considered, since the most complex requirements will impose a large cost relative to the size of the plant. Wind turbine generators with the DFIG-configuration should, ceteris paribus, meet the requirements easier.

5. Minimum requirements for simulation models

As the electricity system evolves and conventional generation and demand facilities are replaced by more complex ones, the system operator needs a better understanding of their structural design and their impact on the dynamic stability of the grid.

To plan and operate the public electricity supply grid effectively, the system operator needs to conduct grid and system dynamic stability analyses, including when connecting new facilities to the grid. This requires precise and up-to-date simulation models of demand and generation facilities connected to the grid.

Simulation models are used to investigate the transmission and distribution grids' static and dynamic stability aspects, including voltage, frequency, small signal stability, rotor angle stability, short-circuit ratios, transient phenomena, and harmonic conditions.

The purpose of this chapter is to recommend general requirements to be stated in the grid connection requirements for facilities connected to the electric grid systems in Vietnam.

This chapter describes:

1. General requirements for electrical simulation models.
2. Requirements for structural design and implementation of stipulated simulation models.
3. Documentation requirements for stipulated simulation models.
4. Verification requirements for stipulated simulation models.

The chapter exclusively focuses on simulation models for asynchronous generation as the report is primarily concerned with outlining the requirements for battery energy storage systems.

The chapter emphasizes the use of RMS-models as the primary starting point for dynamic plant simulation models, as they are currently recommended for a minimum of model requirements. While EMT-models are not recommended at this time due to their complexity, they may be introduced in the future to provide more detailed analysis. This approach allows for a practical and manageable implementation of simulation models, with the potential for more advanced modeling in the future. The properties of the different models will be described in the following section.

5.1. General requirements for electrical simulation models.

In the Danish legislation it is stipulated that the facility owner must submit simulation models to the transmission system operator according to the requirements in the grid connection code. The simulation models must properly reflect the generation facility's steady-state and quasi- steady state properties, this is referred to as a static model. Additionally, the facility owner must also submit a dynamic simulation model i.e. Root Mean Square model (RMS-model) and a transient simulation model i.e. Electro Magnetic Transient-model (EMT-model) to the transmission system operator for time domain analyses. As explained in previous section, requirements for EMT-models will not be discussed further in this chapter.

The facility owner must also submit a harmonic simulation model for analysis of the harmonic pollution of the public electricity supply grid, including the facility's contribution to harmonic emissions in the point of connection. This requirement is also valid for BESS plants and even pure demand facilities.

Please see Table 6 for information on proposed requirements for simulation models and delivery scope for the respective types of generation facilities [10]. The facility owner must ensure that models are delivered on time under current procedures for grid connection of generation facilities and other provisions in the VN regulation.

Generating / demand facility	**Synchronous generation / demand facilities**	**Asynchronous generation / demand facilities**
Type A	No requirement for simulation model	No requirement for simulation model
Type B	Static simulation model RMS simulation model	Static simulation model RMS simulation model
Type C	Static simulation model RMS simulation model	Static simulation model RMS simulation model
Type D	Static simulation model RMS simulation model	Static simulation model RMS simulation model Harmonic simulation model

Table 6 Proposed simulation model requirements for specific generation facility types.

The facility owner must ensure that simulation models are verified with the results of the compliance tests specified in the VN regulation as well as relevant test and verification standards and must submit the required documentation hereof.

If the generation facility incorporates external components, for example to comply with grid connection requirements, the simulation model must include the necessary representation of these components applicable for all required model types.

From the generation facility's design phase to the time of issue of the final operational notification, the facility owner must regularly keep the transmission system operator informed if preliminary facility and model data are no longer representative of the completed, commissioned generation facility.

If a power generation facility consists of several generation modules (wind/solar power plants), several generation groups (blocks) or includes a plant controller, the electrical simulation model must represent all units, components, and software control capability that impacts the facility capability at the connection point. The electrical simulation model must be representative for the complete facility at the grid connection point.

If a facility has more than one grid connection point, a simulation model must be available for each separate grid connection point.

The same requirements are recommended to be valid for demand facilities and BESS facilities.

If significant modifications are made to the properties of an existing generation facility, the facility owner must submit an updated and documented simulation model of the modified facility.

Model delivery is deemed complete only when the transmission system operator has approved the simulation models and required documentation submitted by the facility owner.

5.2. General documentation requirements

To ensure correct model application, the required simulation models must be documented in user guides. These must include descriptions of the simulation models' structural configurations as well as descriptions of simulation model parameterization and valid boundary conditions in the form of operating points and any grid condition restrictions (short-circuit and R/X ratios) in the point of connection and fault location in connection with the simulation of external events in the public electricity supply grid. The user guide must also contain information about special model-technical conditions, e.g., the maximum step size for the equation solver used in connection with the implementation of dynamic and transient simulations etc.

The user guide must also include descriptions of the control, protection and regulation functions implemented in the simulation model to be used when evaluating the generation facility's characteristics in the point of connection, where the following conditions must be in focus:

- Single-line representation of the simulation model's electrical main components up until the point of connection.

- The electrical input and output signals (terminals) of the simulation model, along with conditions related to measuring points, units, and base values, should be described.
- A comprehensive parameter list, where all parameter values are stated in enclosed data sheets for main components, block diagrams and transfer functions, etc.
- Description of structure and activation levels of protective functions used.
- Description of set-up and initialization of the simulation model as well as any limitations to the application hereof.
- Description of how the simulation model can be integrated into a large grid and system model of the public electricity supply grid as used by the transmission system operator.
- Unique version control of simulation model and related documentation.

Model-specific documentation requirements are described in the following sections.

5.2.1. Requirements for static simulation model

The requested simulation model of the generation facility should reflect the static and quasi-static properties of the facility at the point of connection, considering the normal operating range and relevant grid conditions. Quasi-static properties involve the facility's behavior during a short circuit at the point of connection or anywhere in the grid. A short circuit may take the following forms:

- A phase-to-earth short circuit with any impedance in the fault point.
- Phase-to-phase-to-earth or phase-to-phase short circuit with any impedance in the fault point.
- A three-phase short circuit with any impedance in the fault point.

The static simulation model must:

- Be supported by model descriptions that, as a minimum, comprise function descriptions of the main modules in the model.
- Include descriptions of the individual model components and related parameters.
- Include descriptions of the set-up of the simulation model as well as any limitations to the application hereof.
- Include the characteristics of the generation facility’s static operating ranges for active and reactive power, so that the simulation model is not erroneously operated in an invalid operating point.
- Allow for the use of all required reactive power control functions:
  - Power factor control (cos φ control) with indication of the set point.
  - Q control (MVAr control) with indication of the set point.
  - Voltage control, including parameters for droop/compounding applied with indication of the set point.
- Allow simulation of RMS values in the individual phases during symmetrical incidents and faults in the public electricity supply grid.

- Allow simulation of RMS values in the individual phases during asymmetrical incidents and faults in the public electricity supply grid.
- As a minimum, cover the 47.5-51.5 Hz frequency range and the 0.0-1.4 p.u. voltage range.

If a simulation model is used to aggregate individual facilities for a common representation of the generation facility in the point of connection, the model must be able to represent the characteristics of the generation facility in the point of connection. The accompanying documentation must include descriptions of the principles used for aggregation and any limitations on the use of this. Simulation model parameter settings must include complete data sets for the individual facilities and the aggregated facility.

The content and level of detail of the simulation models for the plant controller and individual generation facility must be such that these can be readily integrated into a national / regional grid and system model as used by the transmission system operator and subsequently appear as a complete, fully functional simulation model as required in previous section.

The simulation model submitted must be implemented in the simulation tool specified by the TSO.

The scope and level of detail of data for grid components and other equipment that form part of the facility infrastructure must enable the construction of a complete and fully operational simulation model as required in previous section.

If the static simulation model is identical to the dynamic simulation model described in previous sections, the requirement for a separate static simulation model no longer applies.

The simulation model must be verified as specified in section 5.3.

5.2.2. Requirements for dynamic RMS simulation model

To accurately represent the generation facility, the dynamic simulation model should include both static and dynamic properties at the point of connection. It should also account for set point changes in active and reactive power generation, changes in control mode, and various external incidents in the public electricity supply grid. The incidents that needs to be accounted for are:

- Generator-near faults seen from the point of connection in accordance with the required FRT characteristics, where a short circuit can take the form of:
  - A phase-to-earth short circuit with any impedance in the fault point.
  - Phase-to-phase-to-earth or phase-to-phase short circuit with any impedance in the fault point.
  - A three-phase short circuit with any impedance in the fault point.
- Disconnection, and possible subsequent automatic reconnection, of any faulty grid component in the public electricity supply grid, cf. the above fault sequence, and the resulting vector jump in the point of connection.

- Manual connection or disconnection (without prior fault) of any grid component in the public electricity supply grid and the resulting vector jump in the point of connection.
- Voltage disturbances and near-miss voltage collapses within the required minimum simulation period, cf. details below, and as a minimum within the transient start-up period for the generation facility's transition to a new static state.
- Frequency disturbances of a duration of less than the required minimum simulation period, cf. details below, and as a minimum within the transient sequence for the generation facility's transition to a new static state.
- Activation of imposed system protection (via an external signal) for fast regulation of the generation facility's active power generation in reference to a predefined final value and gradient.

If a simulation model is used to aggregate individual facilities for a common representation of the generation facility in the point of connection, the model must be able to represent the characteristics of the generation facility in the point of connection, cf. above. The accompanying documentation must include descriptions of the principles used for aggregation and any limitations on the use of this. Simulation model parameter settings must include complete data sets for the individual facilities and the aggregated facility.

The content and level of detail of the simulation models for the plant controller and individual generation facility must be such that these can be readily integrated into a large grid and system model as used by the transmission system operator and subsequently appear as a complete, fully functional simulation model.

If the generation facility incorporates external components, for example to comply with grid connection requirements or for the delivery of commercial ancillary services, the simulation model must include the necessary representation of these components as required in previous section.

The simulation model submitted must be implemented in the simulation tool specified by the TSO.

The scope and level of detail of data for grid components and other equipment that form part of the facility infrastructure must enable the construction of a complete and fully operational simulation model as required in previous section.

The simulation model must be verified as specified in section 5.3.

5.2.3. Requirements for harmonic simulation model

The simulation model of the overall generation facility must represent the facility's emissions of harmonics and passive harmonic response (harmonic impedance) in the point of connection, applicable to the defined normal operation range according to the grid connection code and in all relevant static grid conditions under which the generation facility must be operational.

The single-unit model provided should be a Thévenin equivalent, representative of the generation facility's emission of integer harmonics, indicated as RMS voltages as well as the facility's passive responses in the 50-2500 Hz frequency range. The model must include all relevant positive, negative, and zero-sequence impedances within the specified frequency range at a resolution of 1 Hz.

If the facility consists of several generation units, an aggregated simulation model representative of total emissions and total passive harmonic responses in the point of connection must be submitted in addition to the single-unit model. Requirements for frequency range and resolution are identical to those for the single-unit model.

If the generation facility's emissions or impedances are dependent on the facility's operating point, the model must be submitted for three power levels at nominal voltage and zero reactive power: P = 0.0 p.u., P = 0.5 p.u. and P = 1.0 p.u. In addition, a description of the reactive power's impact on harmonic emissions and impedances must be included. In addition, the facility owner must submit a model based on the highest emissions for each harmonic frequency. This applies to both the aggregated and single-unit models. The facility owner shall document any dependencies on the operating point and ensure correct implementation in the models.

The facility owner shall specify a method for summation of emissions from several generation units. This can be done either by specifying the requirement for setting the angle of the Thévenin voltage for each harmonic frequency specifically for each generation unit, or by using a summation law such as the one specified in IEC-61000-3-6: Electromagnetic compatibility [11]. If a summation law is applied, alfa [α] coefficients must be specified by the facility owner. Explanations must be given for the selected α coefficient values for all harmonics. In both cases, the facility owner shall substantiate that the method applied results in a correct representation of the generation facility's total harmonic emissions.

The scope and level of detail of data about grid components and other components of the facility infrastructure must enable the creation of a complete frequency-dependent simulation model in the 50 Hz-2500 Hz frequency range. This includes cables, transformers, filters etc. The scope of the delivery must be approved by the transmission system operator.

5.2.3.1. Harmonic model accuracy requirements

The method used for the creation of a model for the individual generation facility must be specified and approved by the transmission system operator. If model parameters are set based on measurements, a measurement report must be enclosed as documentation. In addition, an account must be given of how model parameters are set using the results in the measurement report. If model parameters are set based on calculations or simulations, the method used must be specified and examples of result processing for the deduction of model parameters given.

5.3. Verification of simulation models

The facility owner must ensure that simulation models are verified according to the requirements in the grid connection code. The facility owner must handle all aspects of the model verification tests, including providing necessary measuring equipment, data loggers, and personnel. The facility owner must also ensure completion and documentation of the required model verification, including documentation of compliance with defined accuracy requirements for the simulation model.

The actual compliance tests must be done as specified in the requirements in the grid connection code where the scope of the verification model has been determined together with the transmission system operator, based on a proposal from the facility owner.

The facility owner is required to create a report documenting the measurements used to verify the simulation model for the generation facility. This report should include descriptions of each data set, detailing the measuring equipment used, data processing methods, and the boundary conditions applied during compliance tests. Additionally, any deviations from the specified boundary conditions and their causes must be documented.

Measured results are compared with the corresponding simulated results and the accuracy of the simulation model is documented in a verification report. The model verification procedure is deemed complete only when the transmission system operator has approved the model verification report submitted by the facility owner.

5.3.1. Verification requirements for static simulation model

Verification is not required; However, it must be documented that the static simulation model is representative of the generation facility’s static and quasi-static properties, where special focus should be on the facility's sub-transient and transient short-circuit contribution in connection with any fault in the public electricity supply grid.

5.3.2. Verification requirements for dynamic RMS simulation model

The facility owner must verify the RMS simulation model for the overall generation facility, including all required control modes and verification of the generation facility’s static and dynamic properties by applying the set point changes and external incidents in the public electricity supply grid described in previous sections.

Model verification is based on measuring results obtained in connection with the completion of type tests or required compliance tests when commissioning the generation facility or by a combination of these, so that the set functional requirements for, and the accuracy of the simulation model can be verified.

For asynchronous generation facilities that consist of several individual installations, have key control, protection, and regulation functions, or use any external components, thus making these facilities come over as aggregate generation facilities in the point of connection, model verification must be completed at an aggregate level and thereby represent all generation facility properties in the point of connection. Requirements for this type of generation facility, cf. previous section, comprise specific simulation models for each type of individual installation (e.g., one model for each turbine type used) and for each type of external component (e.g., one model for each energy storage units used etc.), and so, modelling of these individual installations and external components must be verified separately.

5.1.1.1. *Required signals for verification of asynchronous generation facilities*

Subsequent model verification requires that the following measuring signals, as a minimum, are recorded for the type and compliance tests completed when commissioning the generation facility:

- Active power – measured in the point of connection.
- Reactive power – measured in the point of connection.
- Phase voltages – measured in the point of connection.
- Phase currents – measured in the point of connection.
- Grid frequency – measured in the point of connection.
- Active power – measured on the primary side of the generator transformer.
- Reactive power – measured on the primary side of the generator transformer.
- Phase voltages – measured on the primary side of the generator transformer.
- Phase currents (resulting) – measured on the primary side of the generator transformer.
- Phase currents (active component) – measured on the primary side of the generator transformer.
- Phase currents (reactive component) – measured on the primary side of the genera- tor transformer.
- Control signals (alarms) for activation of fault ride-through functions.
- Signal for activation of system protection.
- Set points for:
  - Active power control.
  - Power factor control (cos φ control).
  - Q control (MVAr control).
  - Voltage control.
  - Frequency or speed control.

5.1. Recommendations for requirements on simulation models in the VN grid connection code

A recommended first approach is to include a minimum set of requirements on electrical simulation models by including the requirements on the RMS models to all grid connected generation and demand facilities type A, B, C and D as soon as possible. This implies synchronous as well as non-synchronous facilities. Requirements for non-synchronous facilities are available in Energinet's guide on requirements for simulation models. [12]

Generating / demand facility	**Synchronous generation / demand facilities**	**Asynchronous generation / demand facilities**
Type A	No requirement for simulation model	No requirement for simulation model
Type B	Static simulation model RMS simulation model	Static simulation model RMS simulation model
Type C	Static simulation model RMS simulation model	Static simulation model RMS simulation model
Type D	Static simulation model RMS simulation model	Static simulation model RMS simulation model EMT simulation model Harmonic simulation model

Table 7 Simulation model requirements for specific generation facility types – step 1

The next step would be to include the requirements on the EMT model for type D generation and demand facilities within a time frame of 5 years from release of the first step.

Generating / demand facility	**Synchronous generation / demand facilities**	**Asynchronous generation / demand facilities**
Type A	No requirement for simulation model	No requirement for simulation model
Type B	Static simulation model RMS simulation model	Static simulation model RMS simulation model
Type C	Static simulation model RMS simulation model	Static simulation model RMS simulation model
Type D	Static simulation model RMS simulation model	Static simulation model RMS simulation model EMT simulation model Harmonic simulation model

Table 8 Simulation model requirements for specific generation facility types – step 2.

Conclusion and recommendations

In conclusion, this report has discussed and formulated connection requirements for Battery Energy Storage Systems (BESS) based on best practices in Europe and Denmark. The findings and recommendations presented here can serve as valuable guidance for Vietnamese lawmakers involved in shaping regulations for BESS integration. Adapting these practices to the local context will ensure safe and efficient integration of BESS, contributing to grid stability and supporting Vietnam's clean energy transition.

It is crucial for Vietnamese lawmakers to consider all types of IBR for when designing connection requirements, and the proposal presented in the annexure can at lengths serve as an inspiration for connection requirements for inverter based generation. The authors recommend a review of the complete set of connection requirements to ensure effective integration of all types of IBR in Vietnam's power system.

The report, drawing from Danish and European best practices, provides guidance to Vietnamese lawmakers on defining design requirements for RoCoF, LFSM, FRT, FFC, and minimal requirements for simulation models.

In general the recommendations can be summarized as:

- Define RoCoF requirements based on the highest observed df/dt, both through simulations and measurements during contingencies (if any). Evaluate the durability of the requirement by considering the expected developments in the generation portfolio over the next 5 years.
- Establish parameters for limited frequency sensitivity modes using modeling of the energy system. Determine various variables for system load, frequency thresholds, droop settings, RoCoF, imbalance, and synchronous operation point. Simulate the frequency response for all possible combinations of the selected variables.
- Determine the design requirement for Fault Ride-Through (FRT) based on fault clearing times. As a rule of thumb, ensure that the plants are robust enough to handle double the maximum clearing times.
- When designing FFC-contribution requirements, prioritize real and reactive current, consider fault needs in different time periods, include optional asymmetric reactive current for non-synchronous generation, and account for network topology, ensuring suitable compromises between system needs and cost-effective requirements.
- With regards to simulation models is it recommended to Introduce RMS models first, followed by EMT models. For simulation requirements. RMS models provide an overview and steady-state validation, while EMT models capture transient phenomena and system dynamics accurately, striking a balance between complexity and accuracy. EMT models are a key component in the future of dynamic simulations and must not be neglected.

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1. Proposing regulations on the operation of BESS in Vietnam's power system

1.1. Words explanation

(1) *Voltage level* is one of the values of the nominal voltage used in the power system, including:

a) *Low voltage* is the nominal voltage up to 1 kV;

b) *Medium voltage* is the nominal voltage from over 1 kV to 35 kV;

c) *High voltage* is the nominal voltage from over 35 kV to 220 kV;

d) *Extra-high voltage* is the nominal voltage over 220 kV.

(2) Dispatching level with control authority is the dispatching level with the authority to command and dispatch the power system according to the dispatching decentralization in the National Load Dispatch Procedure promulgated by the Ministry of Industry and Trade.

(3) *Rated capacity* of a BESS is the maximum AC power that can be discharged and charged of the BESS. This value is calculated and announced, consistent with the DC power of the BESS.

(4) *Voltage fluctuation* is the variation of voltage amplitude from nominal voltage over a period of more than 1 minute.

(5) *Connection point* is the point for the connection of equipment, power grid, power plant and BESS of customers using the transmission or distribution grid to the transmission or distribution grid.

(6) *Frequency control in power system* (hereinafter abbreviated as *frequency control*) is the control process in the power system to maintain the stable operation of the system, including primary frequency control, secondary frequency control and tertiary frequency control:

a) Primary frequency control is the process of instantaneous control of the frequency of the power system that is performed automatically by a large number of generators equipped with a governor system;

b) Secondary frequency control is the next control process of the primary frequency control which is performed through the action of the AGC system in order to bring the frequency to the long-term permissible operating range.

c) Tertiary frequency control is the next control process of the secondary frequency control which is performed by dispatching command to bring the system's frequency to the stable operation state according to current regulations and to ensure economic distribution of power output between generators

(7) *Power system* is a system of power generation equipment, power grid and ancillary equipment linked together.

(8) *National power system* is a power system that is commanded uniformly in the whole nation.

(9) *Transmission power system* is the power system including the transmission grid and power plants connected to the transmission grid.

(10) *Distribution power system* is the power system including the distribution grid and power plants connected to the distribution grid.

(11) *Battery energy storage system* (hereinafter abbreviated as *BESS*) is a system consisting of the following main components:

a) Battery system consists of battery packs connected together to achieve the desired voltage and current values.

b) Battery management system (BMS) is responsible for controlling the battery packs to help them operate within the limits of voltage, current, temperature and state of charge.

c) Power conversion system (PCS) includes inverters responsible for connecting the battery system and converting the current from DC to AC.

d) Energy management system (EMS) is responsible for monitoring and controlling the discharging or charging power of the BESS based on the command of the dispatching unit.

(12) *Supervisory Control And Data Acquisition system* (*SCADA*) is a data collection system to serve the monitoring, control and operation of the power system.

(13) *Black start capability* is the capability of a power plant to start at least one generator from complete inactive state and synchronously connect to the grid without receiving electricity from the regional grid.

(14) *Black start* is the process of restoring the whole (or part of) power system from a state of total (or partial) blackout by using generators with black start capability.

(15) *Power grid* is a system of power transmission lines, power stations and auxiliary equipment for power transmission.

(16) *Distribution grid* is the part of the power grid including lines and power stations with voltage level up to 110 kV.

(17) Transmission grid is the part of the power grid including lines and power stations with voltage level over 110 kV.

(18) *Short Term Flicker Perceptibility (P_{st})* and *Long Term Flicker Perceptibility (P_{lt})* are the measurement value according to the current national standard. In case the values of P_{st} and P_{lt} are not included in the national standard, measurement will be carried out according to the current IEC Standard published by the International Electrotechnical Commission.

(19) *Harmonics* are sinusoidal waves of voltage and current whose frequencies are multiples of the fundamental frequency.

(20) *Remote Terminal Unit/Gateway (RTU/Gateway)* is a device located at a power station or power plant serving the collection and transmission of data to the SCADA system of the load dispatch center or the control center.

(21) *Control center* is a center equipped with information technology and telecommunications infrastructure systems to remotely monitor and control a group of power plants, power stations or switchgear on the power grid.

1.2. Subjects of application

(1) The following recommendations are applied to newly built storage battery systems connected to the power system and participating in the operation of the power system, the battery storage system is retrofitted to the existing power plants or load.

(2) If power plants is retrofitted with additional battery storage systems, the following requirements must be satisfied:

- The following recommendations are applied to a retrofitted storage battery system.
- The infrastructure connected to the power grid of the power plant must ensure the valid regulations and requirements on connection.
- The retrofitted batteries have not violated existing regulations and requirements of the plants and vice versa.

(3) The following recommendations are applied to the battery storage in the power charging and discharging condition.

(4) The following recommendations do not apply to uninterruptible power supplies (UPS) or equivalent systems that ensure uninterrupted power supply to the load in the event of a fault in the power system.

(5) Classification of BESS based on nominal capacity is as follows:

- Class A: BESS with a nominal capacity equal or under 1 MW;
- Class B: BESS with a nominal capacity from over 1 MW to 10 MW;
- Class C: BESS with a nominal capacity from over 10 MW to 30 MW;
- Class D: BESS with a nominal capacity over 30 MW;

- Class SX: batteries are retrofitted to power plants. Where X can be one of the above types A, B, C or D.
- Class T: battery is equipped in electric vehicles or other transport equipment temporarily connected to the power system through a 2-way charging station.

(6) In each of the proposals below, if the requirement for a specific type of battery is not mentioned, it is understood that the proposal applies to all types of battery classified above. The recommendations for class A, B, C and D storage cells also apply to the retrofitted BESS for the power plant.

1.3. General regulations

1.3.1. Frequency range

The nominal frequency of Vietnam’s power system is 50 Hz. The BESS must remain in operation for the minimum time corresponding to the frequency ranges specified in (according to Circular No. 25/2016/TT-BCT [13]).

Table 1-1. The minimum operating time of the BESS corresponding to the frequency ranges

Frequency ranges	Minimum operating time
From 47,5 Hz to 48,0 Hz	10 minutes
From 48 Hz to 49 Hz	30 minutes
From 49 Hz to 51 Hz	Continuous
From 51 Hz to 51,5 Hz	30 minutes
From 51,5 Hz to 52 Hz	01 minute

1.3.2. Voltage range

Nominal voltage levels in Vietnam’s power system include:

- The transmission grid includes 500 kV, 220 kV levels;
- The distribution grid includes 110 kV, 35 kV, 22 kV, 15 kV, 10 kV, 6 kV and 0,38 kV levels.

The BESS with a connection point at the transmission grid must maintain continuous operation in case the voltage at the connection point varies within the ranges specified in

Table 1-2 as follow (according to Circular No. 25/2016/TT-BCT [13] and Circular 39/2015/TT-BCT [14]).

Table 1-2. Normal operating voltage of the transmission grid

Voltage level (kV)	Lower limit (kV)	Upper limit (kV)
500	475	525
220	209	242
110	105	121
35	33	39
22	21	24
15	14	17
10	9.5	11
6	5.7	6.6
0,38	0.36	0.42

1.3.3. Rate of Change of Frequency (RoCoF)

Except for type T, battery cells connected to the grid must maintain operation when the Rate of Change of Frequency (RoCoF) of the system is in the range from 0 Hz/s to 01 Hz/s measured in a time frame of 500 milliseconds (According to Circular 39/2022/TT-BCT [15]).

1.3.4. Automatic connection/ Automatic reconnection

(1) BESS is not allowed to connect or reconnect automatically after a fault in the power grid when the following conditions are not satisfied (According to Circular No. 39/2022/TT-BCT [15]):

- The grid frequency remains in the range from 49,8 Hz to 50,2 Hz for a minimum of 3 minutes;
- All phase voltages at the connection point remain in the range from 90% to 110% of the rated voltage for a minimum of 3 minutes.

(2) The maximum ramp rate per minute of the BESS in the above cases is not greater than 10% of the rated capacity of the BESS (≤10%P_{rated}/min – According to Circular No. 39/2022/TT-BCT [15]).).

1.3.5. Fault-ride-through

(1) Except type T, a BESS that is connected at all times to the grid must maintain operation corresponding to the voltage range at the point of connection for the time illustrated in Figure 1-1 as follows (according to Circular No. 39/2022/TT-BCT[15]):

- Voltage below 0, pu (area E), the BESS must generate the maximum reactive power within the limit to support voltage stability, and maintain a minimum operating time of 0,15 seconds;
- Voltage from 0,3 pu to less than 0,9 pu (area B), the BESS must generate reactive power within the limit to support voltage stability, the minimum operating time is calculated by the following formula:

$$T_{min} = 4xU\text{-}0{,}6$$

  where: T_{min} (s) is the minimum operating time; U (pu) is the actual voltage at the connection point in per-unit system;
- Voltage from 0,9 pu to less than 1,1 pu (area A), the BESS must maintain continuous operation;
- Voltage from 1,1 to 1,2 pu the BESS must charge the reactive power within the limit to support voltage stability (refer to Grid code of South Africa [10]).

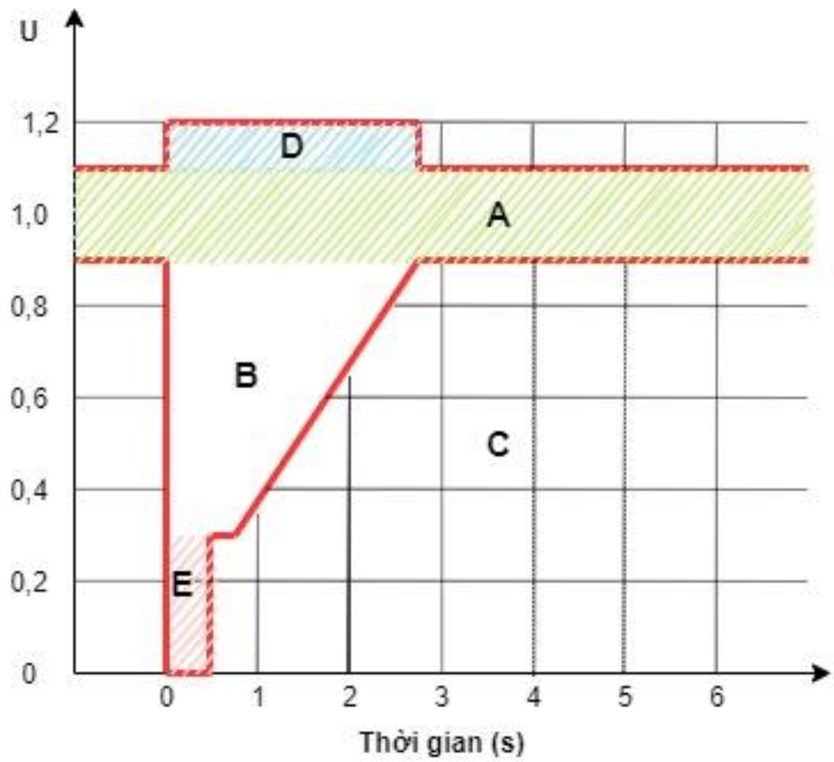

Figure 1-1. Illustration of the fault-ride-through of a BESS

(2) When the voltage at the connection point is restored to the normal working range (area A), the BESS, if it is operating in the power system, must restore to the norminal operating conditions within the time no later than 5 seconds (Danish expert's recommendation - refer to the Danish Grid code [9]).

(3) When the voltage at the connection point is restored to normal working range (Area A), if another contigency occurs causing a voltage drop after 1.5 seconds, the following contigency is considered a new contigency (suggested by Danish experts - refer to the Danish Grid code [9]).

1.3.6. Phase swing/Phase jumps

Except type T, the battery shall be designed to remain in operation when instantaneous voltage phase angle fluctuations of up to 20 degrees occur for a period of 100 milliseconds (Circular 39/2022/TT-BCT [15]).

1.3.7. Fast fault current injection

Class C and D BESS must be able to quickly support the fault current in the event of a symmetrical short circuit (3-phase short circuit) or asymmetrical short circuit (single-phase short circuit, or 2-phase short circuit) at the connection point as follows:

- BESS generates maximum reactive power (usually equal to 1,1-1,2 times the rated current).
- BESS is required to reach the maximum reactive power within 60-80 ms (refer to the Finnish Grid code [17]).
- BESS is installed to activate the fault current support feature when the phase-to-ground voltage at the connection point is lower than 0,85 pu and stop this feature when the phase-to-ground voltage at the connection point returns to 0,9 pu (refer to Finnish Grid code [17]).

1.3.8. Post fault active power recovery

(1) After the fault is cleared, except type T, the BESS, if operating in the power system, must restore the active power to the pre-fault set value with an error of ±5% of that value in a maximum time of 5 seconds (refer to Finnish Grid cod [17]).

(2) The ramp rate per second of the BESS in this case is not less than 30% of the rated capacity and not more than 200% of the rated capacity of the BESS ($30\%P_{rated}/s \leq speed \leq 200\%P_{rated}/s$ – according to Circular 39/2022/TT-BCT [15]).

1.3.9. Black start

At some critical locations, class B, C and D BESS must be able to perform black start. The requirements for black-starting equipment must be specified in the Connection Agreement (as proposed by NLDC - Circular 25/2016/TT-BCT [13]).

1.3.10. Island operation

At some critical positions, class C and D BESS must be able to operate in isolation and be ready to synchronize with the power system when there is a command from the dispatching unit. The requirement for black-starting equipment must be specified in the Connection Agreement (as proposed by NLDC - Circular 25/2016/TT-BCT [13]).

1.3.11. Automatic disconnection

The BESS must be automatically disconnected from the grid when the voltage at the connection point remains continuously outside the normal operating voltage range specified in paragraph 1.3.2 (as proposed by NLDC).

1.3.12. Disconnection of load due to under frequency

The BESS must automatically stop charging power when the frequency of the power system remains below 49 Hz continuously (as proposed by NLDC).

1.4. Active power control and frequency control

1.4.1. Active power control

(1) In active power control mode, the BESS must be able to maintain the active power discharged to or charged from the connection point according to the set value, independent of the change of frequency, unless frequency control mode is activated (refer to Finnish Grid code [17]).

(2) The active power control error of the BESS is within ±5% of the set value, or ±0.5% of the rated capacity (refer to the Danish Grid code [9]).

(3) The active power ramp rate of the BESS every second is not less than 1% of the rated capacity, and not greater than 20% of the rated capacity (refer to the Danish Grid code [9]).

1.4.2. Frequency control

In frequency control mode, the BESS must be able to change the active power according to the change of frequency.

1.4.2.1. Limited frequency sensitive mode - overfrequency (LFSM-O)

(1) When the power system frequency is greater than 50.2 Hz, the BESS must be able to reduce the discharging active power or increase the charging active power according to the relative slope of the droop characteristics in the range from 2% to 10. Relative slope setting value of the droop characteristics is calculated and determined by the dispatching level with control authority (as proposed by NLDC).

(2) The overfrequency response process must begin no later than 2 seconds from the time of recorded frequency above 50.2 Hz and must be completed within 15 seconds (refer to the Danish Grid code [9]).

1.4.2.2. Limited frequency sensitive mode - underfrequency (LFSM-U)

(1) Except class T, when the power system frequency is less than 49.8 Hz, the BESS must be able to reduce the charging active power or increase the discharging active power according to the relative slope of the droop characteristics in the range from 2% to 10%. Relative slope setting value of the droop characteristics is

calculated and determined by the dispatching level with control authority (as suggested by NLDC).

(2) The underfrequency response process must begin no later than 2 seconds from the time of recorded frequency below 49.8 Hz and must be completed within 15 seconds (refer to the Danish Grid code [9]).

1.4.2.3. Frequency senstive mode

(1) Except class T, the BESS when operating in the power system must be able to participate in the primary frequency control process in both directions of charging or discharging active power.

(2) The relative slope of the droop characteristics is in the range from 2% to 10%. Relative slope setting value of the droop characteristics is calculated and determined by the dispatching level with control authority.

(3) The maximum active power range that can be varied is within 100% of the rated capacity of the BESS. The response time of the primary frequency control is not greater than 10s (refer to Danish Grid code [9]).

1.4.2.4. Frequency restoration control

Except class T, the BESS when operating in the power system must be able to participate in the secondary frequency control process in both directions of charging and discharging active power. The response time of the secondary frequency control is not greater than 20 seconds starting from the time the control signal of the dispatching unit is received (according to Circular No. 25/2016/TT-BCT [13]).

1.5. Reactive power control and voltage control

1.5.1. Reactive power capability

The BESS must be able to regulate reactive power equal to or better than the characteristic illustrated in Figure 1-2 as follows (according to Circular No. 30/2019/TT-BCT [16]):

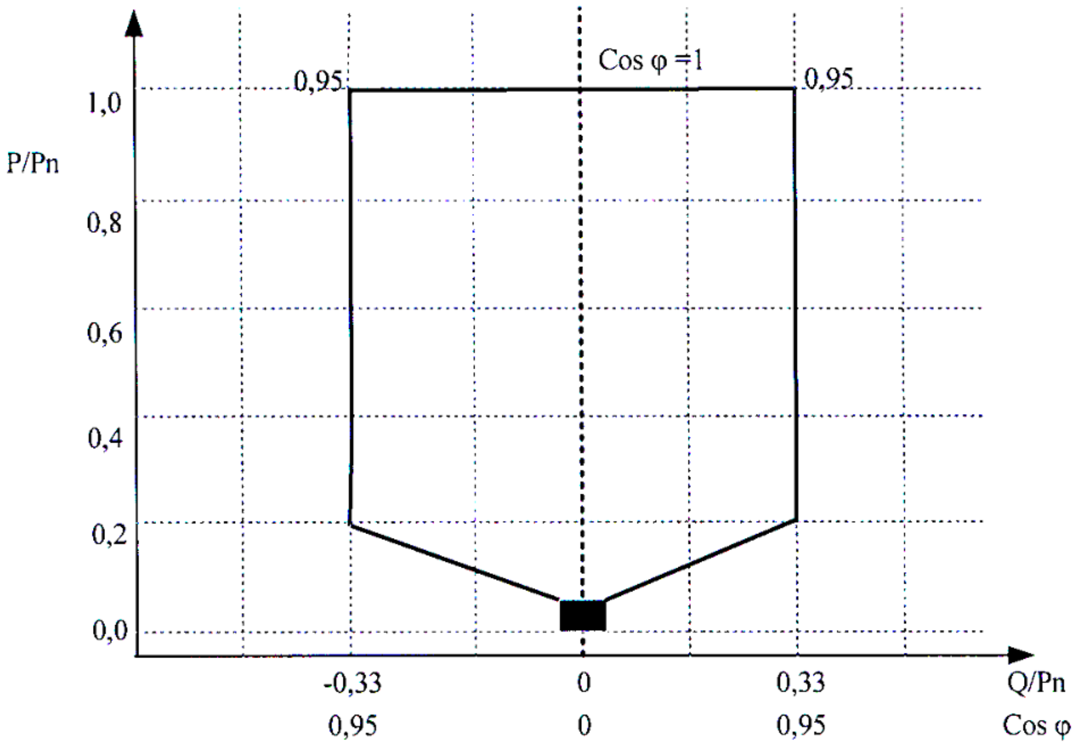

Figure 1-2. Illustration of the reactive power regulation characteristic of a BESS

(1) When the BESS is charging or discharging active power greater than or equal to 20% of the rated active power and the voltage at the connection point is within ±10% of the rated voltage, the BESS has the ability to continuously adjust reactive power in the power factor range from 0.95 or less (reactive power generation mode) to 0.95 or less (reactive power receiving mode) at the connection point corresponding to the rated power.

(2) In case a BESS charges or discharges active power less than 20% of the rated power, the BESS may reduce its ability to receive or generate reactive power in accordance with the characteristic of the BESS.

1.5.2. Voltage and reactive power control modes

Voltage and reactive power control modes include:

- Voltage control.
- Reactive power control.
- Power factor control.

The voltage and reactive power control modes applied to each class of BESS are shown in Table 1-3 (as proposed by NLDC).

Table 1-3. Voltage and reactive power control modes corresponding to classes of BESS

Control modes	Class A	Class B	Class C	Class D
Voltage control		Apply	Apply	Apply

Reactive power control	Apply	Apply	Apply	Apply
Power factor control	Apply	Apply	Apply	Apply

1.5.2.1. Voltage control

Class B, C and D BESS must be capable of setting automatic voltage control at the connection point according to the regulated voltage (Automatic voltage control). The regulated voltage is determined from the reactive-voltage droop characteristic illustrated in Figure 1-3 as follows:

(1) The voltage control range is specified in paragraph 1.3.2.

(2) The reactive power control range is within the reactive power control limit of the BESS.

(3) The relative slope of the reactive-voltage droop characteristic ranges from 2% to 10%. Relative slope setting value of the droop characteristic is calculated and determined by the dispatching level with control authority.

(4) The process of changing the regulated voltage value takes place in no more than 2 seconds. The BESS response must be completed within 10 seconds of receiving the new regulated value (refer to the Danish Grid code [9]).

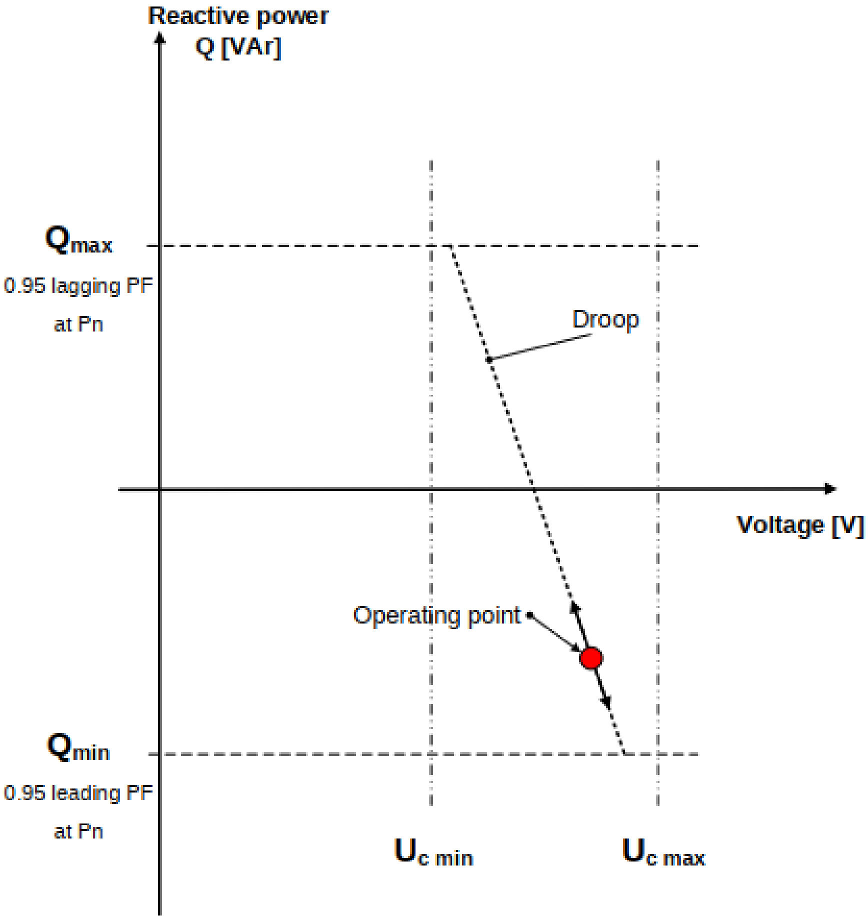

Figure 1-3. Illustration of the reactive-voltage droop characteristic of a BESS [9]

1.5.2.2. Reactive power control

(1) In the reactive power control mode, the BESS must be able to maintain the reactive power generated to or received from the connection point according to the regulated value, independent of the change of the voltage.

(2) The process of changing the regulated value of reactive power takes place in 2 seconds. The BESS response must be completed within 10 seconds of receiving the new regulated value (refer to the Danish Grid code [9]).

1.5.2.3. Power factor control

(1) In the power factor control mode, the BESS must be able to maintain the power factor at the connection point according to the regulated value, independent of the change in voltage.

(2) The process of changing the regulated value of the power factor takes place in no more than 2 seconds. The BESS response must be completed within 10 seconds of receiving the new regulated value (refer to the Danish Grid code [9]).

1.6. Power quality

1.6.1. DC content

The storage battery must not cause the DC content at the connection point exceed 0.5% of the rated current (according to Circular No. 39/2022/TT-BCT [15]).

1.6.2. Voltage imbalance

In normal operation, the negative sequence component of the phase voltage at the connection point shall not exceed 3% of the nominal voltage for voltage levels equal or greater than 110 kV, or 5% of the nominal voltage for medium and low voltage levels (according to Circular No. 30/2019/TT-BCT [16]).

1.6.3. Current imbalance

In normal operation, the difference between the phase currents at the connection point does not exceed 16 A if the battery has a rated capacity equal or lower than 11 kW. Batteries with a capacity greater than 11 kW must ensure a balanced 3-phase current at the connection point in normal operation (as proposed by Danish experts – refer to the Danish Grid code [9]) .

1.6.4. Harmonics

1.6.4.1. Voltage harmonics

The maximum allowable voltage harmonic distortion caused by the battery on the transmission and distribution grid is specified in Table 1-4 as follow (Circular No. 25/2016/TT-BCT [13] and Circular No. 30/2019/TT-BCT [16]):

Table 1-4. Maximum permitted voltage harmonic distortion

Voltage level	Total harmonic distortion (THD)	Individual harmonic distortion
500 kV , 220 kV	3.0%	3.0%
110kV	3.0%	1.5%
Medium	5.0%	3.0%
Low	8.0%	5.0%

1.6.4.2. Current harmonics

The maximum permitted current harmonic distortion caused by the BESS on the distribution grid is specified in Table 1-5 as follow (Circular No. 25/2016/TT-BCT [13] and Circular No. 30/2019/TT-BCT [16]):

Table 1-5. Maximum permitted current harmonic distortion

Voltage level	Total harmonic distortion (THD)	Individual harmonic distortion
500 kV , 220 kV	3.0%	3.0%
110kV	3%	2%
Medium and low	5%	4%

1.6.4.3. Danish expert's proposal on harmonic regulation

Danish experts recommend the following harmonic regulations for battery storage as follow:

(1) The percentage between the individual harmonic currents and the rated current of the battery should not exceed the maximum allowable value in Table 1-6 below.

Table 1-6. Maximum allowable percentage between harmonic current and rated current

Voltage at connection point	Short circuit rate	Odd harmonics							Even harmonics					
		3	5	7	9	11	13	15	2	4	6	8	10	12
≤ 1 kV	<33	3.4	3.8	2.5	0.5	1.2	0.7	0.4	0.5	0.5	1.0	0.8	0.6	0.5
	≥33	3.5	4.1	2.7	0.5	1.3	0.7	0.4	0.5	0.5	1.0	0.8	0.6	0.5
	≥66	3.9	5.2	3.4	0.6	1.8	1.0	0.4	0.5	0.5	1.0	0.8	0.6	0.5
	≥120	4.6	7.1	4.6	0.8	2.5	1.5	0.5	0.5	0.5	1.0	0.8	0.6	0.5
	≥250	6.3	11.6	7.3	1.3	4.4	2.7	0.8	0.5	0.5	1.0	0.8	0.6	0.5
	≥350	7.5	15.0	9.5	1.6	5.7	3.7	1.0	0.5	0.5	1.0	0.8	0.6	0.5
> 1 kV		3.4	3.8	2.5	0.5	1.2	0.7	0.4	0.5	0.5	1.0	0.8	0.6	0.5

(2) The percentage between the individual inter-harmonic currents and the rated current of the battery should not exceed the maximum allowable value in Table 1-7 below.

Table 1-7. Maximum allowable percentage between interharmonic current and rated current

Voltage at connection point	Short circuit rate	Frequency (Hz)		
		75 Hz	**125 Hz**	**> 175 Hz**
≤ 1 kV	<33	0.4	0.6	75/f
	≥33	0.5	0.7	83/f
	≥66	0.6	0.8	104/f
	≥120	0.7	1.1	139/f
	≥250	1.2	1.8	224/f
	≥350	1.5	2.3	289/f
> 1 kV		0.44	0.66	83/f

(3) The percentage of current between 2 kHz and 9 kHz, with a step of 200 Hz, and the rated current of the battery should not exceed 0.2 %.

1.6.5. Voltage fluctuation

The voltage fluctuation at the connection point on the grid caused by the BESS must not exceed 2.5% of the nominal voltage and must be within the permitted operating voltage value for each voltage level (Circular No. 25/2016/TT-BCT [13]).

1.6.6. Flicker

The maximum permitted voltage flicker perceptibility caused by the BESS on the grid is specified in Table 1-8 as follow (Thông tư số 25/2016/TT-BCT [13] và Thông tư số 30/2019/TT-BCT [16]):

Table 1-8. Permitted voltage flicker perceptibility

Voltage level	$P_{lt95\%}$	$P_{st95\%}$
220, 500 kV	0.6	0.8
110 kV	0.6	0.8
Trung áp	0.8	1.0
Hạ áp	0.8	1.0

1.7. Data communication

(1) BESS connected to the grid with a capacity equal or greater than 10 MW must be equipped with an information system and this connection must be compatible with the information system of the grid operation management unit and the dispatching level with control authority. The connection must also ensure that communication and data transmission (including data of SCADA system, PMU, fault recorder) is adequate, reliable and continuous for power system and power market operation. The minimum means of communication for dispatching and operation, including direct channels, telephones and faxes, must operate reliably and continuously.

(2) The BESS management and operation unit is responsible for investing, installing, managing and operating the information system within the scope of its management. The BESS management and operation unit may agree to use the information system of the power grid operation management unit or another supplier to connect to the information system of the dispatching level with control authority, ensuring continuous and reliable information for the operation of the power system and the power market.

(3) The list of information signals is presented in Table 1-9 as follow (proposed by Danish expert).

Table 1-9. List of information signals

Signal	Class A	Class B	Class C	Class D
Stoping	x	x		
Maintain operation	x	x		
Status of the circuit breaker at the common connection point of the system including the battery and other elements (if any)		x	x	x
Circuit breaker status at the storage battery connection point		x	x	x
Active power at connection point		x	x	x
Active power setting value (current set value)			x	x
Available active power control properties				x
Available reactive power control properties				x
Active power change rate limit		x	x	x
Maximum active power setting value		x	x	x
Active current at the connection point		x	x	x
Reactive power at connection point		x	x	x
Reactive power control (on/off)		x	x	x
Reactive power setting value at connection point		x	x	x
Power factor at connection point		x	x	x
Power factor control (on/off)		x	x	x
Power factor setting value at connection point			x	x
Voltage at connection point			x	x
Voltage control (on/off)			x	x
Voltage control slope			x	x
Value of applied voltage			x	x
Security system			x	x

1.8. SCADA

(1) The BESS connected to the grid with a capacity equal or greater than 10 MW that is not connected to the control center must be equipped with a Gateway or RTU and set up two physically independent connection channels with the SCADA system of the dispatching level with control authority.

(2) The BESS connected to the grid with a capacity equal or greater than 10 MW or more that is connected, controlled and operated remotely from the Control Center

must be equipped with a Gateway or RTU and set up a connection with the SCADA system of the dispatching level with control authority and two connections to control system at the control center.

(3) In case a BESS has multiple dispatching levels with control authority, the dispatching levels are responsible for sharing information in service of coordinating the operation of the power system n.

(4) The BESS management and operation unit is responsible for investing, installing, managing and operating RTU/Gateway equipment within the scope of management, data transmission or leasing data transmission of the service provider to ensure continuous, complete and reliable connection and data transmission to the SCADA system of the dispatching level with control authority and the control system of the Control Center (if any).

(5) RTU/Gateway of the BESS must have compatible technical characteristics and ensure connection with the SCADA system of the dispatching level with control authority and the control system of the Control Center (if any).

(6) The dispatching level with control authority is responsible for integrating the data according to the data list agreed with the BESS management and operation unit into its SCADA system. The BESS management and operation unit is responsible for coordinating with the dispatching level with control authority to configure and set up a database on its system to ensure compatibility with the SCADA system of the dispatching level with control authority and the control system of the Control Center (if any).

(7) In case the SCADA system of the dispatching level with control authority has a change in technology and is approved by the competent authority after the time of signing the Connection Agreement, resulting in the need to change or upgrade the control system, RTU/Gateway of the BESS management and operation unit, the dispatching level with control authority, the BESS management and operation unit are responsible for coordinating the corrections required for the BESS Operation and Management Unit's equipment to be compatible with the SCADA system changes. The BESS management and operation unit is responsible for investing in and upgrading the control system, RTU/Gateway to ensure compatible connection with the SCADA system of the dispatching level with control authority.

(8) Class D batteries must be equipped with a fault recording monitoring system with GPS (Global Positioning System) (Circular 25/2016/TT-BCT [13]). When a fault occurs, the fault logging monitoring system must record the following information (refer to the Danish Grid code [9]):

- Voltage on each phase of the battery.
- Current on each phase of the battery.

- Active power of the battery (which can be a calculated value).
- Reactive power of the battery (which can be a calculated value).
- Frequency of the battery (which can be a calculated value).

The lowest sampling frequency of the fault logging monitoring system is 1 kHz, the fault logging data is presented as a time series from 10 seconds before the fault to 60 seconds after the fault (refer to the Danish Grid code [9]). Incident logs must be kept for at least 3 months.

(9) The storage battery management and operation unit must submit to the dispatcher with control authority information on data and fault logs within the last 3 months upon request (refer to Danish Grid Code [9]).

1.9. Protection

Battery storage connected to the grid at voltage level equal or higher than 110 kV or with a capacity equal or greater than 10 MW must be equipped with a protection system.

(1) The protection system shall have the necessary configuration, protection functions and settings to ensure that the BESS is protected from faults occurring within the BESS and from failure on the grid.

(2) The dispatching unit with control authority specifies the configuration, protection functions and settings necessary to protect the power grid, taking into account the characteristics of the BESS. The grid protection system settings must be specified in the Connection Agreement.

(3) The BESS management and operation unit specifies the configuration, protection functions and settings necessary for the BESS to protect devices and elements in the system. The settings of the BESS protection system must ensure that the BESS maintains the minimum operating time in the event of a failure on the power system.

(4) The dispatching unit with control authority must send to the BESS management and operation unit information about the lowest and highest short-circuit currents at the connection point as well as other necessary information to coordinate the control functions of the BESS.

(5) The dispatching unit with control authority is allowed to change the settings of the BESS protection system to suit the operating conditions of the power system, but must not cause damage or danger to equipment and components in the BESS.

(6) The protection system for class C and D shall have a control of the active power according to pre-set values. The specific setting values are calculated and adjusted by the authority dispatching unit. The default setting values include: 0%, 10%, 40%, 50% and 70% of the battery's rated capacity. Active power emergency power control

ensures no deviation by more than 1% of the power factor setpoint within 1 minute (proposed by Danish experts - Grid code Denmark [9]).

(7) The main protection functions for battery storage include (Danish expert recommendation - Grid code Denmark [9]):

- Overvoltage protection.
- Undervoltage protection.
- Over frequency protection.
- Underfrequency protection.
- Frequency change rate limit protection.
- The dispatching unit has the right to control setting the impact value and operating time of the protection system.

1.10. Priority order of control and protection system

The priority order of control and protection system is as follows (refer to the Danish Grid code [9]):

(1) Protection functions (Section 1.9).

(2) Frequency control (Section 1.4.2.1 and Section 1.4.2.2).

(3) Frequency senstive mode (Section 1.4.2.3).

(4) Limiting capacity and change in capacity (Section 1.4.1).

Basic requirements for BESS

Regulations	A (SA)	B (SB)	C (SC)	D (SD)	T
Frequency range	x	x	x	x	x
Voltage range	x	x	x	x	x
Rate of Change of Frequency (RoCoF)	x	x	x	x	
Automatic connection	x	x	x	x	x
Automatic reconnection	x	x	x	x	x
Ramping limit during automatic connection/reconnection	x	x	x	x	x
Fault ride through	x	x	x	x	
Phase swing/phase jumps	x	x	x	x	
Sym faults/asym faults - voltage assistance			x	x	
Post fault active power recovery	x	x	x	x	
Black start		x	x	x	
Island operation		x	x	x	
Automatic disconnection - high/low voltage disconnection	x	x	x	x	x
Disconnection of load due to under frequency	x	x	x	x	x
Active power control	x	x	x	x	x
Limited Frequency Sensitive Mode at Overfrequency (LFSM-O)	x	x	x	x	
Limited Frequency Sensitive Mode at Underfrequency (LFSM-U)	x	x	x	x	
Frequency Sensitive Mode	x	x	x	x	
Frequency restoration control	x	x	x	x	
Reactive power capability	x	x	x	x	x
Voltage control		x	x	x	
Reactive power control	x	x	x	x	
Power factor control	x	x	x	x	
DC content	x	x	x	x	x
Voltage imbalance	x	x	x	x	x
Current imbalance	x	x	x	x	x
Voltage harmonics	x	x	x	x	x
Voltage harmonics	x	x	x	x	x
Voltage fluctuation	x	x	x	x	x
Flicker	x	x	x	x	x
Data communication			x	x	
SCADA			x	x	
Protection			x	x	

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