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Performance Comparison Between Hydropower & Battery-Based Frequency Containment Reserves in the Nordic Power System

Static Contingency Analysis of Current & Future High-Renewable Scenarios

Degree project report in Electrical Engineering

GUSTAF THORDIN
JOHAN TRAN

DEPARTMENT OF ELECTRICAL ENGINEERING

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Gustaf Thordin
Johan Tran

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Supervisors: Peiyuan Chen & Wenfa Kang, Department of Electrical Engineering,
Chalmers University of Technology
Examiner: Peiyuan Chen, Department of Electrical Engineering, Chalmers
University of Technology

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Department of Electrical Engineering
Chalmers University of Technology
SE-412 96 Gothenburg
Sweden
Telephone +46 31 772 1000

Cover: Geographical visualization of power flows between Nordic bidding zones
(generated with power flow visualization tool created by the authors).

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Abstract

As power systems transition toward high shares of renewable energy generation, maintaining grid frequency stability becomes increasingly complex. This degree project investigates the performance of hydropower and battery energy storage systems (BESS) as frequency containment reserves (FCR) in the DK2, SE4, and SE3 bidding zones during contingency events in a future power system scenario characterized by high wind generation and varying demand. The investigation assesses potential improvement in transmission capacity and grid efficiency in the congested area of southern Sweden and eastern Denmark during contingencies. Using updated Nordic 56 that contains 56 busbar and a detailed DK2 grid models with 141 busbars as the simulation environment in PowerFactory, the work evaluates network robustness under both pre-contingency and post-contingency conditions. Static contingency simulations focused on the operational envelope of the 0.95–1.05 voltage in p.u. and phase angles of $\pm 30^\circ$ within transmission networks to identify deficiencies and assess proximity to voltage violations and angular instability. The simulations showed that increased BESS FCR participation relieves transmission capacity in contingencies during current and future high wind high load conditions, but also corresponded to increased losses in future high wind low load conditions. The increased losses likely correlate to a future shift in generation and demand centers in the Nordics, with a corresponding shift in congested transmission corridors across the Nordic power system, rendering BESS FCR located in DK2, SE3 and SE4 less effective during low load conditions. Consequently, depending on the grid loading conditions, these potential alleviations could unlock previously reserved transmission capacity for energy markets, thereby influencing electricity price. Limitations concerning the simulations were noted, including the lack of dynamic modeling which likely influenced the static simulation outcomes.

Keywords: Grid stability, Nordic56, DK2, N-1 contingency, Power system simulation, PowerFactory.

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Gustaf Thordin & Johan Tran, Gothenburg, May 2026

List of Acronyms

Below is the list of acronyms that have been used throughout this thesis listed in alphabetical order:

BESS	Battery Energy Storage System
BZ/BZs	Bidding Zone(s)
CE	Continental Europe
DER	Distributed Energy Resource
FCR	Frequency Containment Reserve
FCR-D	Frequency Containment Reserve (Disturbance)
FCR-N	Frequency Containment Reserve (Normal)
FRR	Frequency Restoration Reserve
EV	Electric Vehicle
GFL	Grid-Following (Inverter)
GFM	Grid-Forming (Inverter)
GW	Gigawatt
HVDC	High Voltage Direct Current
HWLL	High Wind Low Load
HWHL	High Wind High Load
IBR/IBRs	Inverter-Based Resource(s)
MW	Megawatt
NPS	Nordic Power System
PV	Photovoltaic
RES	Renewable-based Energy Sources
RoCoF	Rate of Change of Frequency
SG	Synchronous Generator
TSO	Transmission System Operator
UFLS	Under Frequency Load Shedding

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1

Introduction

The transition to a higher degree of renewable energy sources (RES) creates major challenges for power systems management in the Nordic grid. Substantial consideration is required on how to ensure continued grid stability, given the stochastic nature of RES and their power electronic interface to the grid.

An essential part of grid stability is the frequency containment reserve (FCR), which stabilizes the frequency in normal operation (FCR-N) and disturbances (FCR-D). Denmark's FCR-D contribution in the Danish-Swedish market was 7.6% in 2025 [1], and in the FCR-N market 37% in 2025 [1]. The interest in new sources of FCR in DK2, such as battery energy storage systems and batteries in electric vehicles (EVs), has increased in recent years. These smaller FCR assets are termed distributed energy resources (DERs).

Given the increasing share of RES in the Nordic grid and the FCR potential of DERs, it would be valuable to model and assess their performance. This degree project details the development of an updated and expanded DK2 model, which is then integrated with a simplified model of the Nordic transmission grid, referred to as the N56 model. The combined DK2/N56 model is subjected to a contingency event, aiming to compare the performance of hydro and BESS FCR, as well as assessing the system's post-contingency stability.

1.1 The Nordic Power System

The Nordic power system (NPS) consists of the national power systems of Norway, Sweden, Finland, and eastern Denmark (DK2). As shown in Fig. 1.1, these countries are divided into 11 bidding areas designed to manage grid congestion and facilitate efficient energy markets [2]. The bidding areas are connected via AC links and several HVDC links, and share a nominal frequency of 50 Hz. The western Danish area (DK1) is synchronized with the Continental European grid and is not considered part of the NPS.

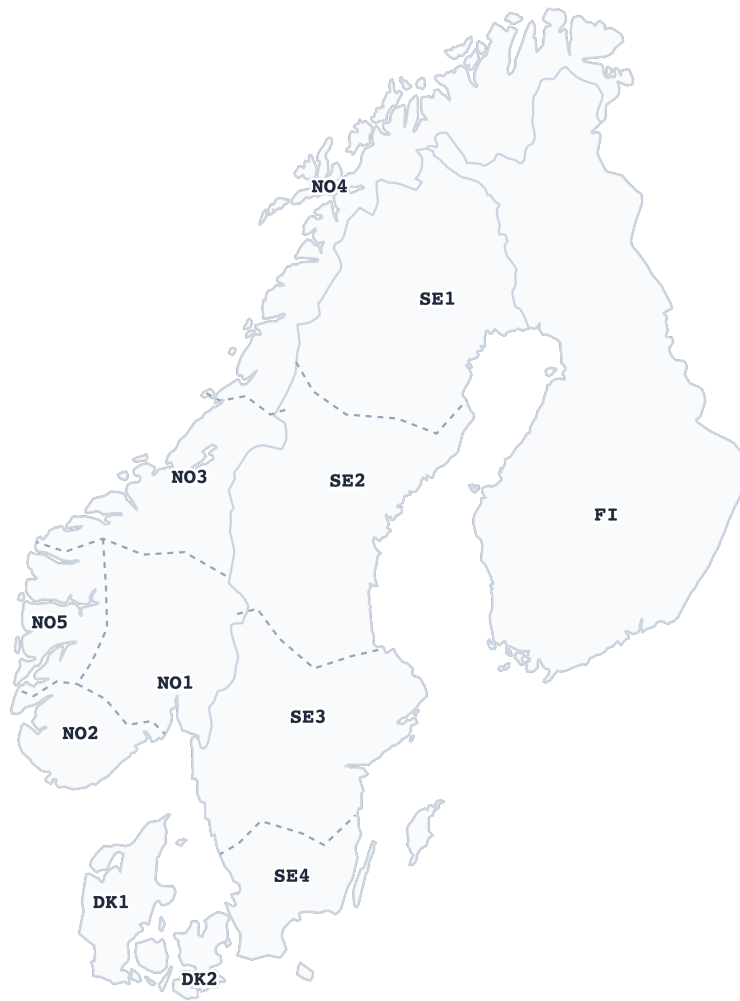


Figure 1.1: Map of the Nordic countries and their bidding areas. DK1 is synchronized with Continental Europe.

1.2 Renewable Energy Sources & Grid Stability

The increased integration of RES, such as wind and solar power, has introduced challenges in Nordic power grid management. Nordic transmission system operators (TSOs) estimate that by 2050, the share of wind and solar will be 75% of total capacity, compared to today's 30% [3].

Unlike traditional synchronous generators (SGs) used in hydro and nuclear plants, RES is inverter-based, which fundamentally affects how the grid maintains its generation/demand balance. Inverter-based resources (IBRs) decrease rotational inertia, increase sensitivity to frequency variation, and reduce short-circuit capacity and voltage stability. As a result, RES integration requires additional ancillary services for grid stability and introduces new grid-utilization methods, including grid-forming (GFM) IBRs [3]. The majority of today's RES use grid-following (GFL)

IBRs, which sync to the grid voltage during operation. GFM IBRs can establish voltage and frequency on their own, enhancing the grid's resiliency and stability, as well as providing capability to operate in low-inertia or islanded environments [3].

Ancillary services provide frequency-control measures such as frequency containment reserves (FCR), and voltage control such as reactive power compensation. FCR responds quickly and automatically to limit a frequency disturbance, and is divided into FCR-N for normal frequency variation, and FCR-D for larger disturbances. FCR can be used to regulate the frequency upwards and downwards [1]. In the Nordic grid, FCR requires reservation of grid capacity in already stressed transmission corridors [4], since hydropower plants located in the north provide a large part of normal power generation and FCR capability where major disturbances are located further away from the hydropower plants.

Since DK2 is part of the Nordic grid, the Danish and Swedish energy markets are connected. Their combined FCR-D up-regulation need is 610 MW, of which DK2 share is 43 MW, while the combined FCR-D down-regulation need is 512 MW, of which DK2 share is 42 MW [1]. FCR has typically been provided by hydro in the NPS, but in recent years battery-based energy storage (BESS) is increasing its share of FCR [1]. In addition, updated TSO requirements for ancillary services have opened for small-scale assets such as DERs, which can harness the latent energy in EV batteries [5]. According to [1], EVs pre-qualified to provide FCR-D up-regulation amount to 25.5 MW in 2024.

1.3 Contingency Scenarios

Modern power systems are designed and operated according to the fundamental reliability standard N-1 [6]. N-1 requires the power system to operate within operational limits after the unexpected loss of a major component, such as a large generating unit, a transmission line, or a transformer [7]. Contingency planning may be required to prepare for cascading failures such as N-1-X, where the grid experiences the loss of one critical unit (N-1) and begins remedial action, followed by the failure of a second component (X).

1.4 Aim of the Project

This degree report aims to identify more efficient ways to distribute Nordic FCR reserves, focusing on DK2 and southern Sweden. It explores whether local FCR assets in the southern part of the NPS can reduce the burden on the transmission system in the event of a contingency, and whether this shift can unlock restricted transmission capacity and improve grid efficiency by reducing reliance on hydro-based FCR.

1.5 Specific Goals

1. Review past cascading contingencies and identify mechanisms that may cause system instability.
2. Model DK2's transmission grid and update its parameters, and then integrate it in the Nordic 56 model for load flow and static contingency analysis.
3. Assess the post-contingency steady state condition of the Nordic grid in four scenarios of high wind generation and varying demand, along with FCR performance of hydro and BESS/EVs.
4. Evaluate localized FCR assets for improving the post-contingency power flow and transmission capacity in the Nordic grid.

1.6 Limitations

- Denmark's western grid DK1 will not be included, since it is synchronously connected with Continental Europe.
- One substation each in DK2, SE4 and SE3 will be expanded for the purpose of BESS integration.
- Dynamic simulations will not be performed: as such, no transient behavior will be captured.

2

Theory

In this chapter, technical terms and concepts related to power grid management are presented and explained.

2.1 Frequency Stability & Inertia

System frequency is an indicator of the real-time balance between active power generation and load. If generation is less than demand, energy is extracted from the rotational inertia of synchronous generators, slowing the rotors and lowering frequency. Should generation be larger than demand, the surplus energy accelerates the rotating masses and increases frequency. Consequently, a synchronous system's frequency stability is maintained by keeping the differential between generation and demand as close to zero as possible.

A grid's synchronous generators (SGs) are electromagnetically coupled, making frequency a global parameter. Conventional plants (hydro, nuclear and thermal) provide inherent stability through the rotational inertia of their SGs. Conversely, inverter-based resources (IBRs) like wind and solar lack a direct mechanical link to the grid. While IBRs do not contribute any inertia in their default setting, they must actively monitor frequency deviations to maintain synchronization.

The time derivative of the frequency is RoCoF, Rate of Change of Frequency [8]. It is the speed at which the frequency deviates following a power imbalance. It is defined as:

$$\text{RoCoF} = \frac{df}{dt} = \frac{\Delta P_{MW} \cdot f_0}{2H \cdot S_{total}} \quad (2.1)$$

where ΔP is the difference between active power generation and demand, H is the system's inertial constant, f_0 the nominal frequency and S_{total} the system's total nominal power. As can be seen in (2.1), a high inertia H decreases RoCoF and gives the system more time to stabilize. A comparison of low and high inertia constant H on a system's frequency can be seen in Fig. 2.1.

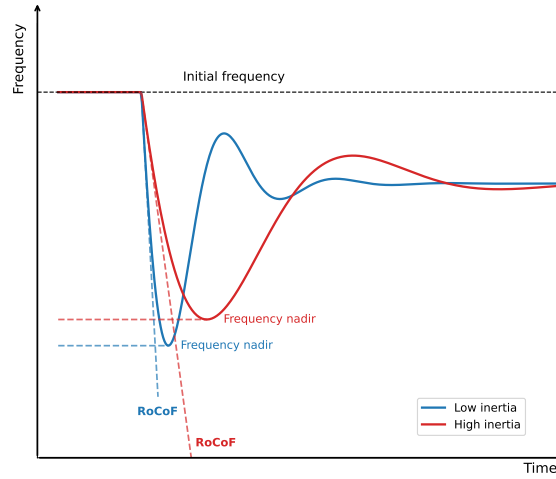


Figure 2.1: The impact of low vs. high inertia (H) on frequency response.

2.1.1 Droop & Primary Frequency Bias

Droop (R) is a generator control characteristic. It defines how much a generator's output power changes in response to a frequency deviation, expressed as a percentage:

$$R = \frac{\Delta f}{f_n} / \frac{\Delta P}{P_{rated}} \quad (2.2)$$

A 4% droop means that a 4% change in frequency (e.g. 2 Hz in a 50 Hz system) produces a 100% change in output. In practice, droop values are typically 4–6%. The key insight is that droop is intentionally non-zero – if all governors tried to fully restore frequency ($R = 0$), they would fight each other. Droop lets multiple units respond to frequency deviations proportionally without coordination. Droop is a physical/mechanical governor setting and thus a property of the individual machine.

A related concept is primary frequency bias (B). Frequency bias is an area-wide/regional parameter used in automatic generation control (AGC). B represents how much the total area's generation responds to frequency deviations, and is expressed in MW/Hz. It can be viewed as the aggregate droop of all the area's generators. It is defined as:

$$B = \frac{\Delta P}{\Delta f} \quad (2.3)$$

As an example, if an area's total frequency bias is 1500 MW/0.5 Hz, it means that all generators involved in frequency response will output a total of 1500 MW if the frequency drops by 0.5 Hz.

2.1.2 Grid-Following & Grid-Forming Inverters

An inverter is a power electronic device that changes DC to AC. Inverters are essential for connecting RES, such as wind turbines and solar farms, to a synchronous

grid. Today, most of these IBRs are grid-following. A GFL IBR's control system uses a Phase-Locked Loop (PLL) to track the grid's voltage waveform and injects a current vector aligned with the grid's voltage, essentially behaving like a current source [9]. Since a GFL IBR relies on an external voltage reference, it will shut down to protect itself if a large voltage or frequency disturbance occurs (such as a steep RoCoF). This can cause instability, since system inertia decreases in a grid with a high share of IBRs. As shown in Eq. 2.1, a decreased inertia H leads to a smaller denominator, resulting in a higher RoCoF (all else equal). These larger frequency deviations challenge the response time of frequency control reserves, and can also cause GFL IBRs to disconnect during contingencies.

Grid-forming inverters, on the other hand, can autonomously regulate their frequency and voltage, while simultaneously synchronizing power transmission [10]. A GFM IBR can thus be considered a voltage source, since it establishes its own internal voltage phasor.

2.2 Voltage Stability & Reactive Power

If frequency serves as a global indicator of a grid's active power balance, voltage magnitude is a local indicator of system stability. This localization stems from the coupling between voltage magnitude and reactive power (Q). The approximate voltage drop ΔV over a high-voltage transmission line can be expressed as:

$$\Delta V \approx \frac{RP + XQ}{V_n} \quad (2.4)$$

where V_n represents the nominal bus voltage [11]. In high-voltage power grids, lines are highly inductive, meaning the inductive reactance is significantly larger than the resistance ($X \gg R$). Because of this high X/R ratio, the RP term in Eq. 2.4 becomes negligible compared to the XQ term, simplifying the equation to:

$$\Delta V \approx \frac{XQ}{V_n} \quad (2.5)$$

Consequently, changes in reactive power Q have a direct impact on voltage magnitude ΔV . To manage this, reactive power compensation, such as capacitor banks or static VAR compensators (SVCs), is typically installed in close proximity to generators or large industrial loads to regulate the local voltage.

2.2.1 Voltage Ride-Through & Fault Ride-Through

Based on the technical framework of IEEE Standard 2800-2022 [12], voltage and fault ride-through (VRT/FRT) requirements are defined as the mandatory ability of an IBR to remain connected and continue operating during voltage or frequency disturbances. As the share of IBRs increase in systems like the Nordic grid, these requirements become critical for maintaining stability, since they lack the inertia and short-circuit capacity (SCC) of traditional SGs.

Fault ride-through capabilities are essential for preventing cascading system failures. For instance, faults occurring close to the point of IBR measurement can cause voltage sags; without robust ride-through capabilities, these sags could cause large-scale simultaneous tripping of IBRs, leading to a severe power imbalance and potential blackout. To actively support the grid during such events, [12] mandates *Dynamic Voltage Support*, where IBRs must provide reactive current to help arrest the voltage drop and facilitate recovery. Furthermore, the standard requires that IBRs ride through consecutive voltage deviations, ensuring stability during the rapid tripping and reclosing sequences common during short-circuit faults.

2.3 Frequency Containment Measures

The implementation of frequency control in a power system follows a hierarchical approach, characterized by differing activation speeds and purposes. While the RoCoF determines the urgency of the initial response, the total magnitude of the required reserve is dictated by the scale of the active power imbalance (ΔP). The different measures are designed to provide the system with the necessary time to mitigate deviations and eventually restore the frequency to its nominal value [13].

2.3.1 Inertial response & Fast Frequency Reserve (FFR)

Inertia provides an instantaneous response of the rotational masses in the grid's synchronous generators. A higher inertia constant H buys more time for the frequency measures that follow. The Fast Frequency Reserve (FFR) provides fast power support from fast-acting sources, such as batteries, supercapacitors or GFM IBRs.

2.3.2 Frequency Containment Reserves (FCR)

The purpose of FCR is to contain frequency deviations to steady-state values within a defined interval, before they reach levels that may trigger load shedding or disconnection of generation [14]. This objective is met through the joint action of FCR within the whole synchronous area.

FCR is divided into FCR-N (Normal) and FCR-D (Disturbance). Table 2.1 details the Nordic FCR distribution. The FCR-D of the Nordic synchronous area is dimensioned for the reference incident of losing its largest generator, i.e. the nuclear reactor Oskarshamn 3 in Sweden, rated at 1450 MW [15]. The frequency containment process in the Nordic grid is supported by Fast Frequency Reserves (FFR) during low inertia conditions [15].

Table 2.1: FCR distribution in the Nordic grid for 2026 [15].

Parameter	Value
Nordic FCR-N	600 MW (minimum)
Nordic FCR-D	1450 MW
Dimensioning of FCR-N & FCR-D	
Sweden	226 MW (38%)
Norway	226 MW (38%)
Finland	128 MW (21%)
Denmark (DK2)	20 MW (3%)

Frequency Thresholds for FCR Activation in the Nordic Grid

1. **49.90 - 50.10 Hz:** Normal operating range handled by FCR-N. If $\Delta f = 49.90/50.10 \text{ Hz} = \pm 0.10 \text{ Hz}$, 100% of FCR-N must be activated.
2. **49.50 Hz < f_{actual} < 49.90 Hz:** FCR-D Up gets activated when the frequency breaches 49.90 Hz, and is fully activated at 49.50 Hz. Should the frequency drop to 49.50 Hz, 50% of FCR-D Up must be activated within 5 seconds, and 100% within 30 seconds.
3. **50.10 Hz < f_{actual} < 50.50 Hz:** FCR-D Down gets activated when the frequency breaches 50.10 Hz, and is fully activated at 50.50 Hz. Should the frequency rise to 50.50 Hz, 50% of FCR-D Up must be activated within 5 seconds, and 100% within 30 seconds.

2.3.3 Distributed Energy Resources (DERs) in the Nordic Grid

Power grids are seeing an increased penetration of DERs. Small-scale DERs, like EVs and distributed energy storage systems, can be aggregated into Virtual Power Plants (VPPs) to meet the minimum capacity requirements for FCR in Nordic countries, allowing them to participate in the energy bidding market [16]. In the context of FCR, IBRs like EVs are capable of much faster activation than hydro units, which has historically been the major type of FCR provider in the Nordic grid. As such, aggregated EVs can essentially be considered FFR resources.

EVs can act as both generation and demand units by modulating the rate of discharging or charging of their batteries, depending on the frequency deviation. The power transfer can be either unidirectional (V1G) or bi-directional (V2G). V1G manages the rate of charge of the EV; electricity always flows from the grid to the EV. V2G enables energy to flow both ways, and allows the EV to support the grid. When sufficiently many EVs have been aggregated and passed TSO prequalification, they participate as a block that provides upward or downward regulation of the frequency, on the same terms as other FCR providing units.

2.4 Power Flow Analysis

Electric power flows continuously from generation units to consumers through interconnected networks of transmission lines and substations. The distribution of power within a system is determined by the network's topology and grid impedances. Power flow analysis describes how electricity is distributed between different parts of the network and how heavily loaded each component is under normal and disturbed conditions.

When electricity flows through transmission lines, heat loss is unavoidable due to the electrical resistance of the transmission lines. Heat loss is related to the flow of active power, while the network's inductive and capacitive properties cause energy to oscillate as reactive power. Both flows are distributed in the grid according to its topology, impedance, busbar voltage magnitudes and phase angles. Hence, the connection of the network determines where active power is delivered and/or lost, and how reactive power supports voltage levels.

2.4.1 Active & Reactive Power Flow

The single-phase transfer of active power P through a lossless ($R = 0$) transmission line is outlined in the equation below.

$$P = \frac{V_1 V_2}{X} \sin(\delta) \quad (2.6)$$

V_1 is the generator bus voltage, V_2 the line voltage, X the reactance of the transmission line, and δ the angle difference between the two buses of the line. δ is kept small (well below 90°); if δ were to exceed 90° , the generator V_1 and the line V_2 would start to lose synchronism.

Similarly, the reactive power Q transferred across the same lossless transmission line is given by:

$$Q = \frac{V_1}{X} (V_1 - V_2 \cos(\delta)) \quad (2.7)$$

Under normal operating conditions, the transmission angle δ is small. In such cases, $\cos(\delta) \approx 1$, which simplifies the relationship to show that reactive power flow is driven by the voltage magnitude difference $V_1 - V_2$ between the two buses. This reinforces why voltage control needs to be managed locally, as outlined in section 2.2, through reactive power compensation, since the transport of Q over large reactances X leads to significant voltage drops.

2.4.2 Transmission Line Constraints

The ability of a transmission line to transfer power is determined by the stability limit of the system and the thermal limit of the line. These constraints ensure that the grid has room for contingencies.

The major transmission constraint of a long line is the stability limit, which is determined by the power angle δ . δ is vital to monitor in order to keep the grid within operational limits. As can be derived from Eq. 2.6, the theoretical maximum active power flow is when $\delta = 90^\circ$. However, in reality, when generator and transformer reactances are taken into account, δ increases for a given load. As such, δ is usually limited between $30^\circ - 45^\circ$ in order to compensate for line reactance [11]. Operating the line at $\delta = 90^\circ$ would provide no room for contingencies, since the line would be fully loaded.

The lesser – but not insignificant – constraint is the physical thermal limit of the lines themselves. An increase in a conductor’s temperature from active power loss will stretch the conductor, which causes the transmission line to sag as it passes between transmission towers. If the temperature is high enough, this stretching will be irreversible [11], and a sufficiently high current could damage the conductor.

2.4.3 Load Flow Analysis

Load flow analysis is an essential part of analyzing power systems and their contingencies. In this report, *DIgSILENT PowerFactory* is used to perform load flow, using the Newton-Raphson method. The method solves the non-linear algebraic power flow equations through an iterative, linearizing process. It determines the voltage magnitudes (V) and phase angles (δ) at every node to satisfy the system’s active and reactive power constraints. Four quantities are involved in load flow: voltage magnitude V , phase angle δ , active power P and reactive power Q . After a load flow has been performed, it is possible to see how loaded a bus or transmission line is. The buses of a system are grouped into three different types [11]:

Slack bus: The reference bus of the whole system, often containing the reference machine(s). Voltage and phase angle (defined as 0°) are specified. The power output is flexible, which allows the bus to adjust or absorb whatever amount of power that is necessary during the simulation’s iterative process to balance the grid equation.

Load bus: Active and reactive power are specified at this bus, while voltage and phase angle are unknown. Also called PQ buses.

Regulated bus: These are generator buses or voltage-controlled buses. Active power and voltage are specified, while phase angle and reactive power are unknown. Also called PV buses.

2.5 Contingency Analysis

Contingency analysis is the primary method to provide secure and resilient operation of power systems in large parallel networks. These analyses are regularly performed and planned according to the N-1 criterion. The N-1 criterion specifies that the grid should remain stable and operational after the loss of one major component (e.g. a generating unit or a transmission line) [17]. Events are considered *credible contingencies* if they have been specifically foreseen when designing the system, and measures have been implemented to mitigate them [17]. However, power systems also experience *non-credible contingencies* (i.e. unforeseen disturbances) due to single, simultaneous and/or cascading outages [17]. Therefore, contingency analysis serves as a framework for analyzing the resilience of power systems under normal and extreme conditions [18]. The fundamental goal of contingency analysis is to evaluate power system stability after disturbances.

2.5.1 Contingency Sequential Modeling

A contingency can be a single, simultaneous, or cascading outage of multiple system components. A simultaneous failure means that two or more components fail at the same time due to an external common cause. In contingency analysis, this is often referred to as an N-k contingency. They can be caused by lightning strikes, cyber attacks or physical events like earthquakes, and happen independently from the grid's condition. A cascading failure is a sequence of events. It starts with a trigger, for example an N-1 outage, and then it propagates as power is forced to find new ways when grid components fail. This redistribution of power flow creates a cycle: **Failure** → **Overload** → **Protective trip** → **Overload** and so on. There is a delay between each cascading step as the grid tries to adjust. TSOs use stability analysis and cascading simulations to see if a single point of failure risks a total blackout.

ENTSO-E regulations stipulate that European grids must withstand single failures, i.e. N-1 contingencies. Exceptional contingencies such as N-2, N-3 etc., that are likely under certain conditions, must be prepared for. Out-of-range contingencies are too expensive to prevent entirely, which shifts the focus from prevention to Defense Plans [19], which entails load shedding as a remedial action. In the Nordic grid, the following N-1 dimensioning contingencies are defined accordingly [20]:

Loss of power generating unit: Tripping of Oskarshamn 3 in Sweden (1450 MW).

Loss of demand facility: Tripping of an aluminum smelter hall in Norway.

HVDC interconnector: Tripping of the Nordlink HVDC cable in an export/import situation.

Loss of line(s): Tripping of Hasle-Halden 420 kV AC line(s) resulting in system protection schemes activating in Norway.

Busbar failure: Single busbar failure resulting in the tripping of more than one generation unit or demand facility.

2.5.2 Contingency Stability Metrics

Voltage magnitudes: Voltage stability is tied to the management of reactive power Q . Unlike frequency, which is a global parameter, voltage is highly localized. A significant voltage drop indicates that local reactive power demand exceeds supply, or that transmission lines are heavily loaded, causing high reactive power losses. If voltage drops below or rises above critical thresholds (typically 0.95–1.05 p.u.), it can trigger a cascading failure known as voltage collapse. This occurs when the system can no longer supply the reactive power required to maintain the voltage profile.

Angular stability: The phase angle difference between two nodes determines the transmission of active power P across a line. This relationship is governed by the power-transfer equation [11]:

$$P = \frac{V_1 V_2}{X} \sin(\delta_1 - \delta_2) \quad (2.8)$$

V_1 and V_2 are terminal voltages, X is line reactance, and $(\delta_1 - \delta_2)$ is the phase angle difference. A larger phase angle difference signifies a higher power transfer and increased electrical distance between the terminals. It acts as a direct measure of stress in a transmission corridor. The theoretical steady-state stability limit is reached when the angle difference approaches 90° . If a disturbance (such as an N-1 contingency event) pushes the angle beyond sustainable limits, synchronous generators can lose synchronism. This leads to pole-slipping, transient instability, and eventual system separation.

RoCoF: RoCoF is the most important metric for the state of health of a power system, with respect to frequency stability. According to ENTSO-E, the current maximum manageable RoCoF of the system protection schemes in Europe is ≤ 1 Hz/s. Less RoCoF means more time for FCR to act to arrest the frequency deviation, while a higher RoCoF gives FCR less time to act.

Frequency limits: For European TSO simulations to be acceptable, the operational frequency limits of 47.5 and 51.5 Hz must not be reached/exceeded, and the final steady-state frequency must be equal or close to 50 Hz. If either limit is reached or exceeded, power generating units may trip along with load shedding being initiated, and the simulation is considered a failure.

3

Analyses of Real Contingencies

To construct a realistic scenario for the PowerFactory simulation in this report, several real contingency events were analyzed to identify critical failure mechanisms. The 2025 Iberian blackout involving Spanish and Portuguese power systems, the 2019 Hornsea incident in the UK, and the 2016 South Australian blackout were studied in-depth. All of these events involved the tripping of a large amount of wind and solar/PV generation, which made their failure mechanisms interesting from the perspective of this report.

Important events in each incident are sequentially numbered in the corresponding timeline figures, with detailed technical explanations provided for each incident; the explanatory text is also supplanted with a bolded number (**X**) to denote the corresponding sequential event in the timeline figures. The key findings are then presented at the end of the section, which aim to identify possible mechanisms that contribute to cascading failures in the grid. Public data, in the form of incident reports, was downloaded from the relevant TSO websites and used to build the graphs and maps [21], [22], [23].

Google Gemini Pro 3.1 was used to create a Python code template for the plot designs in this chapter. The template and subsequent designs were then modified by the authors depending on the data presented in the TSO incident reports.

3.1 Iberian Peninsula Blackout 28 April 2025

Conditions during the morning of 28 April 2025 were normal, with typical spring weather for South-West Europe. Solar PV and wind generation were high, with Spain exporting 5 GW to Portugal, France and Morocco. From 9:00, Spain voltage variability started increasing, with a peak close to 435 kV at 10:30. Significant oscillations occurred 30 minutes before 12:32:00; the first was a local Iberian power oscillation phenomenon with a frequency of 0.63 Hz, and the second was an East-Center-West oscillation of 0.2 Hz [21].

Fig. 3.1 showcases the progression of the incident and the most significant losses of power generation. The bolded numbers correspond to the sequence presented in Fig. 3.2. In total, approximately 10.1 GW of power generation and 11.3 GW of load was tripped between 12:32:00 to 12:33:25 [21].

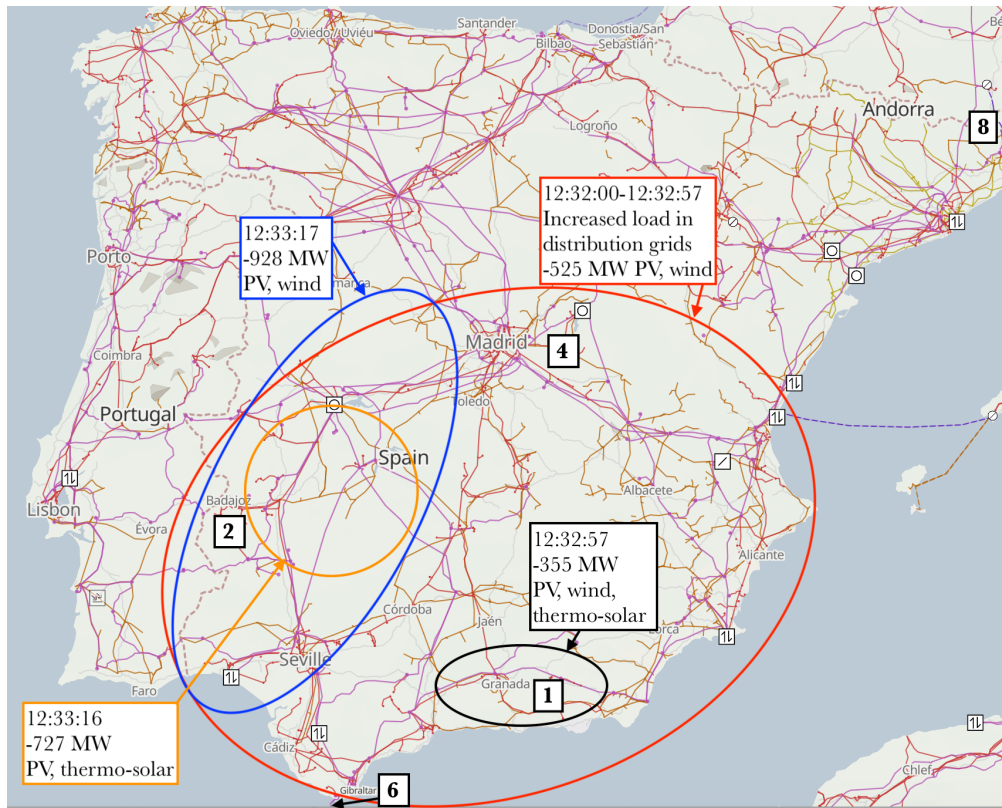


Figure 3.1: Incident map of the Iberian system showing location of events 1, 2, 4, 6 and 8. [24]. Adapted with permission.

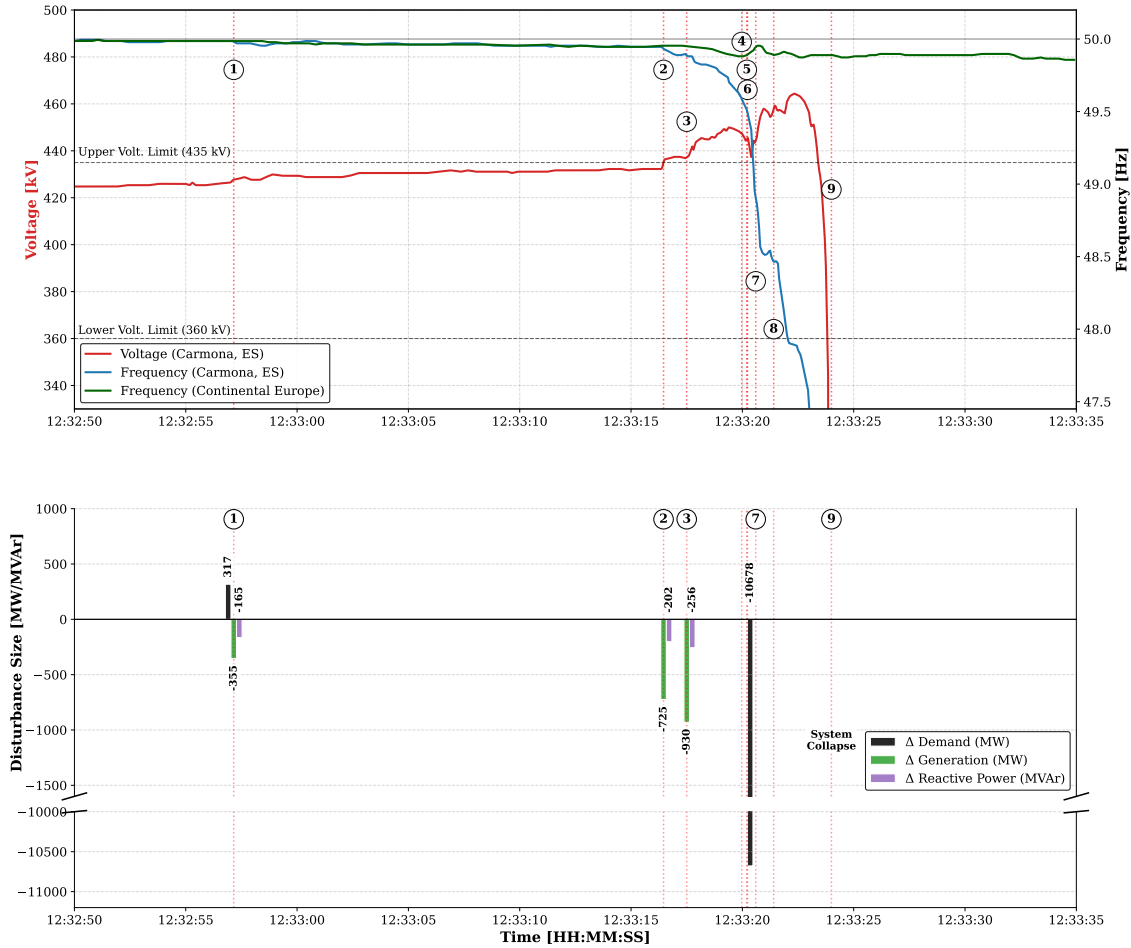


Figure 3.2: Timeline of the Iberian power system blackout on 28 April 2025.

- | | |
|---|--|
| <p>1: 12:32:57: Transformer at Granada substation tripped → loss of wind, PV and thermo-solar generation (-355 MW).</p> <p>2: (+19 s) Tripping of two Badajoz 400 kV lines (-725 MW).</p> <p>3: (+20 s) Solar generation cascade disconnection (-928 MW).</p> <p>4: (+22.9 s) Arganda 220 kV breaker opened due to incorrect voltage measurement (false overvoltage).</p> | <p>5: (+23 s) Increasing loss of synchronism between Iberian peninsula and Continental Europe → start of system separation.</p> <p>6: (+23.2 s) Morocco separation. Pump storage in Spain and Portugal disconnected.</p> <p>7: (+23.6 s) Under-frequency load shedding triggered (10.7 GW).</p> <p>8: (+24.4 s) France separation.</p> <p>9: (+27 s) Total system collapse.</p> |
|---|--|

From 12:32:00, initial solar PV and wind generation losses (708 MW) and a demand increase (317 MW) preceded the 12:32:57 trip of a Granada 400/220 kV transformer. Triggered by Phase B overvoltage (242.9 kV) on the 220 kV side, the trip removed 355 MW of active power and 165 MVar of reactive absorption, causing a system-wide voltage step-increase [21] **(1)**.

At 12:33:16, the loss of a 400 kV line and a PV plant in Badajoz (725 MW, 202 MVar) further destabilized regional voltage **(2)**. This triggered a 928 MW cascade of solar PV disconnections across multiple regions between 12:33:17 and 12:33:18, which also reduced reactive absorption by approximately 256 MVar **(3)**. These trips, caused by protection misalignment, accelerated the voltage rise by removing further reactive absorption capability [21].

By 12:33:19, an incorrect voltage measurement at Loeches substation caused an undesired opening of the Arganda-Loeches 220 kV line **(4)**. Simultaneously, the system lost synchronism with Continental Europe, resulting in severe power swings and a RoCoF exceeding -1 Hz/s **(5)**. Subsequent defense actions included tripping of the Morocco interconnection (49.5 Hz and shedding 4600 MW of pumped storage load **(5)**). Although UFLS shed an additional 10.7 GW, the imbalance persisted **(7)**.

Following the loss of AC interconnections with France (12:33:21), the Iberian Peninsula briefly entered island mode **(8)**. The collapse concluded at 12:33:23 as the Santa Llogaia-Baixas HVDC lines tripped and frequency fell below 44 Hz, leading to a total blackout by 12:33:27 [21] **(9)**.

3.2 Hornsea Incident 9 August 2019

Prior to the incident detailed in fig. 3.4 below, 32 GW of generation was available in the UK system, of which 30% consisted of wind generation and 50% of conventional generation. Load demand was forecast at 29 GW. A number of transmission lines were out of service, which is normal during the summer period. Yellow weather warnings had been issued for southern England [22].

Fig. 3.3 showcases the progression of the incident and the most significant losses of power generation. The bolded numbers correspond to significant sequential events presented in Fig. 3.4. In total, approximately 1.9 GW of power generation and 931 MW of load was tripped between 16:52:30 to 16:56:30 [21].

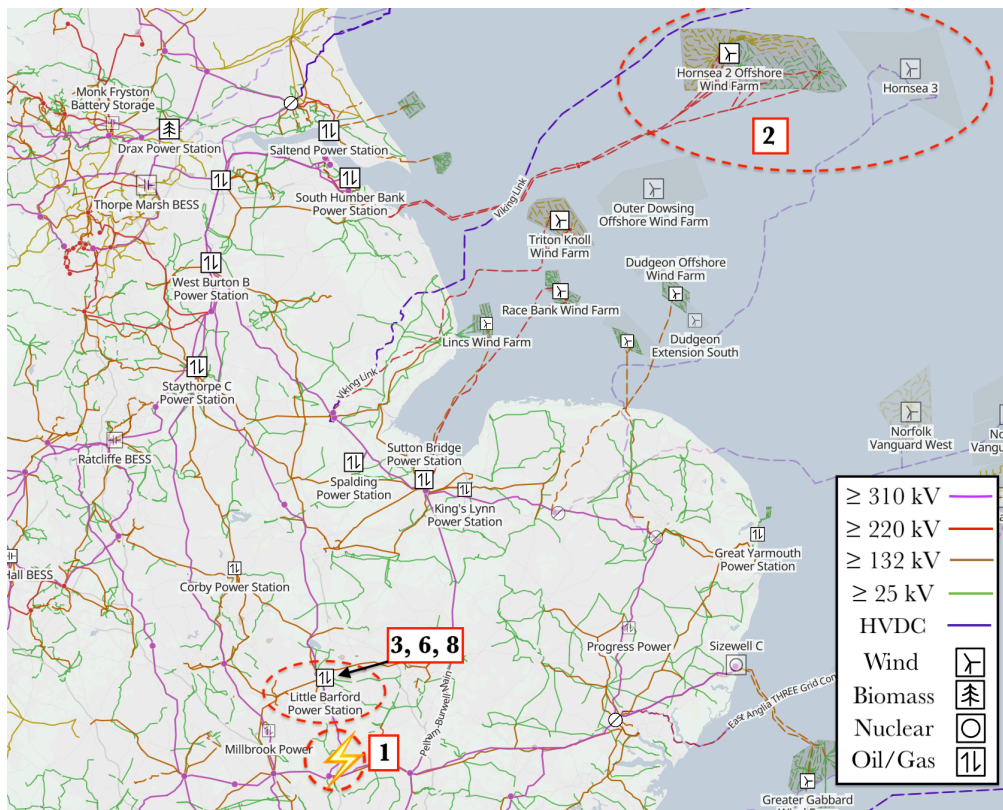


Figure 3.3: Incident map of the South-Eastern UK system showing location of events 1, 2, 3, 6 and 8. [25]. Adapted with permission.

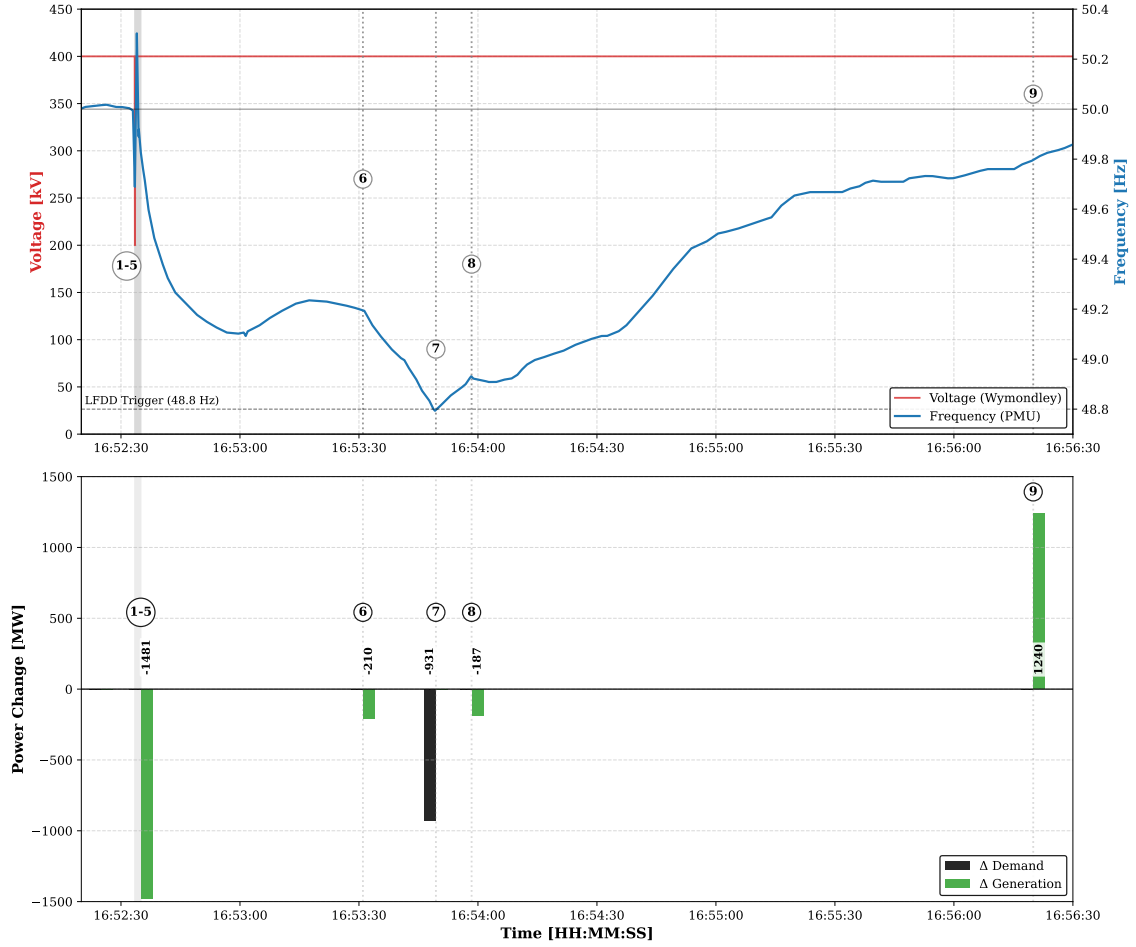


Figure 3.4: Forensic timeline of the 9 August 2019 UK grid incident.

- 1: 16:52:33.490:** A lightning strike on the 400 kV circuit caused a single-phase-to-earth fault → trip of embedded generation by vector shift protection (-150 MW).
- 2: (+0.24 s)** Hornsea wind farm de-loaded rapidly (-737 MW).
- 3: (+0.51 s)** Little Barford (LB) steam turbine tripped (-244 MW).
- 4: (coincident with 3)** Embedded generation tripped by RoCoF protection (- 350 MW).
- 5: (coincident with 3)** Rapid frequency decrease.
- 6: (+57.51 s)** First gas turbine at LB tripped (-210 MW).
- 7: (+75.91 s)** Frequency fell below 48.8 Hz → 931 MW load shed.
- 8: (+84.51 s)** Manual (intentional) trip of second gas turbine at LB (-187 MW).
- 9: (+106.51 s)** Frequency restoration actions → 50 Hz reached 16:57:15 (not shown).

The faults caused by the lightning strikes were cleared within 74 ms. Coincident with the faults, an estimated 150 MW of embedded generation across the UK tripped on vector shift protection **(1)**.

As the transmission system voltage started recovering after the fault clearance, Hornsea started deloading unexpectedly **(2)**. Two circuit assets at the wind farm were out of service, and the wind turbine controllers reacted incorrectly to an insufficiently damped electrical resonance in the sub-synchronous frequency range as the system voltages recovered. This led to a local voltage drop at Hornsea, and the turbines shut down. This reduced output from 799 MW to 62 MW [22].

Then, 0.26 seconds after the Hornsea deload, the steam turbine at Little Barford tripped due to a discrepancy between three speed signal measurements **(3)**. One minute later, the first gas turbine tripped due to a rapid pressure increase in the steam-bypass system **(6)**. Continuing high pressure forced Little Barford staff to manually trip the second gas turbine 30 seconds later **(8)**. The cumulative loss of Little Barford generation amounted to 641 MW [22].

Coincident with the first turbine trip at Little Barford, an estimated 350 MW of embedded generation in various parts of the UK system tripped due to RoCoF protection **(4)**. In addition to this, several embedded generator and demand customers reported that they were disconnected when the frequency fell below 49 Hz a few seconds prior to 16:54:00, causing a further generation loss of 200 MW (protective measures at 49 Hz was not expected and had not been observed previously according to NESO [22]).

About 18 seconds after the second turbine trip at Little Barford, the frequency fell below 48.8 Hz, automatically activating the Low Frequency Demand Disconnection protocol **(7)**. 931 MW of demand was disconnected (approximately 3.2% of total demand in UK at the time, affecting 1.1 million customers), marking the culmination of the cascading event [22].

3.3 South Australian Blackout 28 September 2016

In the minutes preceding the events displayed in Fig. 3.6, the South Australian (SA) grid was already operating under major stress [23]. From 16:16:46 to 16:18:08, four faults occurred in the 275 kV transmission grid due to extreme weather which damaged several transmission lines. These accumulating faults initiated the contingency event detailed in this section, which led to the separation – and subsequent blackout – of the SA grid from the National Electrical Market (NEM), Australia’s national grid [23]. Fig. 3.6 outlines the final seconds before blackout occurred in the SA grid, and can be considered the culmination of the contingency event.

Fig. 3.5 [23] showcases the progression of the incident; it has been reprinted with permission. Between 16:18:00 and 16:18:16, a rapid generation deficit triggered an emergency load shedding of 932 MW. However, the frequency collapsed too quickly for the defense schemes to stabilize the grid, resulting in the total loss of all 1213 MW of local generation and a complete regional blackout of 1826 MW of demand.

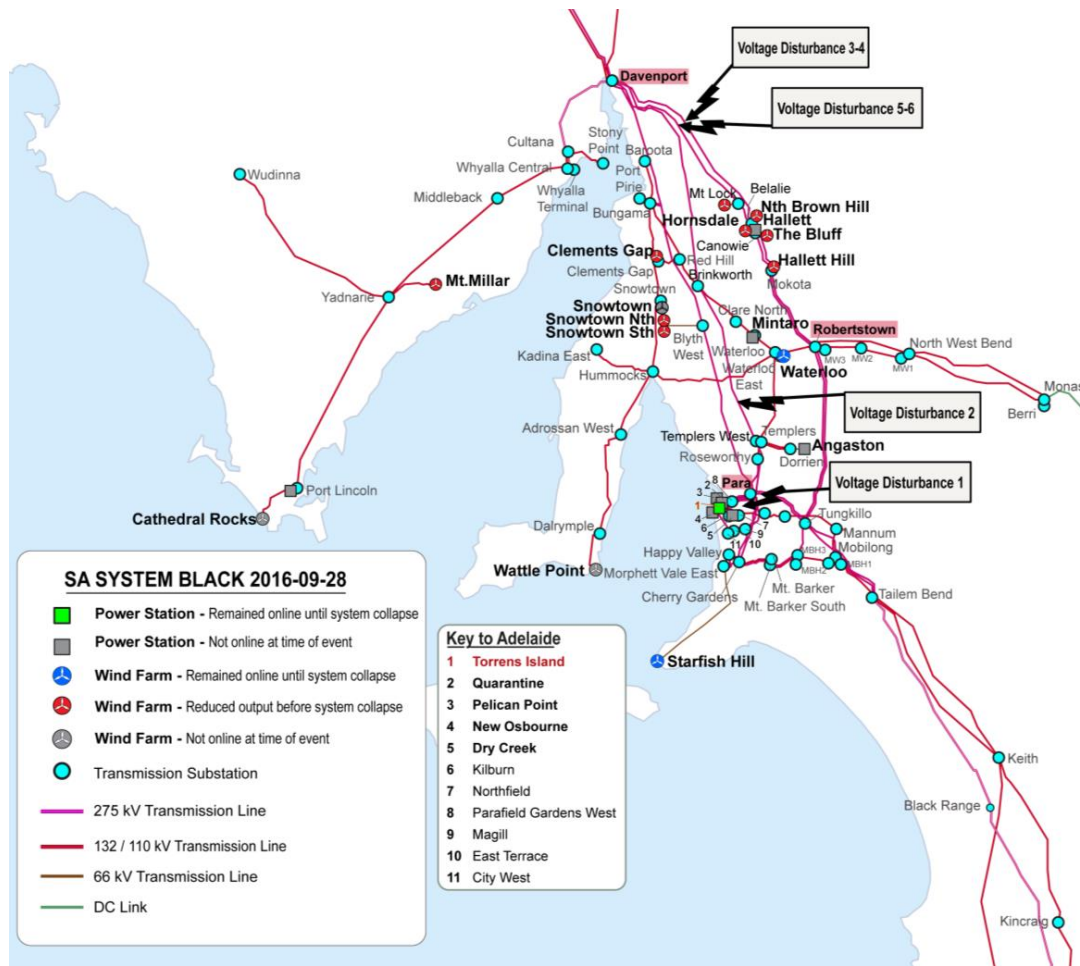


Figure 3.5: Incident map of SA system showing location of faults and major stations. [23]. Reprinted with permission.

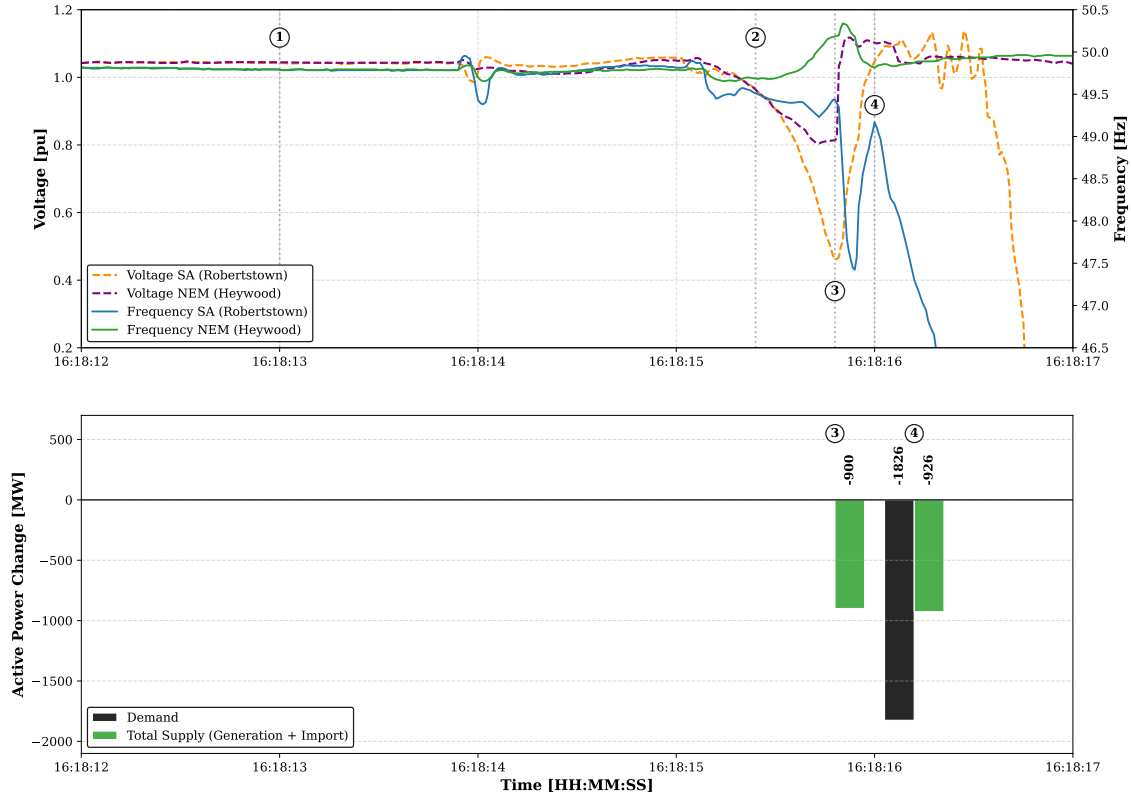


Figure 3.6: Timeline showing the last seconds prior to the 28 September 2016 South Australia blackout.

- 1: 16:18:13:** A single-phase-to-ground fault occurred on the Davenport-Mt Lock 275 kV line, causing voltage at Davenport to drop to approximately 0.4 pu.
- 2: (+2.45 s)** The cumulative reduction in wind generation reached 456 MW. The Heywood interconnector flow increased to compensate, maintaining total supply at the 1826 MW demand level.
- 3: (+2.84 s)** The Heywood interconnector tripped on loss of synchronism protection, separating the SA grid from NEM (- 900 MW).
- 4: (+3.0 s)** With a massive supply-demand deficit, the SA frequency fell below 47 Hz. Despite UFLS activation, the SA power system collapsed into a "Black System" at 16:18:16:00.

AEMO's report [23] concludes that, as a direct result of the electrical faults **(1)**, nine wind farms reduced their power output by a combined 456 MW due to voltage drops following the faults **(2)**.

The loss of 456 MW, in addition to transient losses of 42 MW due to wind farm fault ride-through mechanisms, caused flows on the Heywood interconnector to spike in order to provide the demand in power. The relative voltage phase angle between SA and the rest of the Australian grid thus exceeded 90° , and coupled with declining voltages and increased current on the interconnector, its automatic loss-of-synchronism protections tripped it. At this point, the SA and NEM systems separated [23] **(3)**.

The relatively low amount of conventional generation, coupled with a high degree of RES, resulted in low inertia conditions in SA. Immediately after separation from NEM, the SA system experienced minor overvoltages before the frequency collapsed. The frequency decline across SA was a direct consequence of the 966 MW of accumulated generation loss from the wind farms and Heywood interconnector.

RoCoF was 6 Hz/s following the interconnector loss - more than double that of previous system separations between SA and NEM - which negated any beneficial effects of UFLS. UFLS can operate quick enough to arrest the frequency if RoCoF ≤ 3 Hz/s - and successful UFLS implementation would have shed 60% of demand in this case - but since the remaining load would have been 800 MW, AEMO concludes that the remaining generation could not have met the demand. A blackout was thus unavoidable [23] **(4)**.

3.4 Key Findings

Grid collapses in systems with high RES are rarely the result of a single failure, but rather a sequence of cascading events triggered by combinations of physical faults and control system sensitivities.

The Iberian blackout highlights the dangers of overvoltage and IBR-driven instabilities in high RES scenarios. The initial loss of 355 MW wind and solar generation removed reactive absorption capacity, causing system-wide voltage increases. This eventually triggered a protection misalignment cascade, where another 928 MW of solar PV disconnected because they could not handle the voltage increase.

The Hornsea incident is an example of IBR control systems reacting incorrectly to electrical resonance, and of RoCoF-induced tripping. The trigger was a lightning strike on the 400 kV circuit which was correctly cleared. The Hornsea windfarm controller system nonetheless reacted incorrectly to an electrical resonance as the voltage recovered, causing it to rapidly decrease output. This in turn caused frequency to drop and further tripping at a conventional power station. RoCoF protection eventually tripped 350 MW of embedded generation, which caused further frequency deterioration and conventional generator trips, ultimately ending the cascade with 931 MW of UFLS.

The South Australia blackout highlights the vulnerability of low-inertia grids and the failure of UFLS during extreme RoCoF. Storms caused faults on the 275 kV grid, which resulted in windfarms reducing their output due to fault ride-through failures. This in turn caused a power spike on a large interconnector, which quickly tripped as the power angle between the areas it connected exceeded 90° . This caused a system separation, and in the low-inertia SA island, RoCoF reached 6 Hz/s: far too fast for UFLS to have time to arrest the fall and prevent a blackout.

4

Methods

In this chapter, the methodology for creating the simulation environment and extracting the simulation data is presented. Python scripting was developed manually, with OpenAI’s ChatGPT occasionally used for guidance, troubleshooting and error identification. The implementation was verified by testing the scripts and checking that the generated values and executed commands matched the expected results.

4.1 Creating the DK2 Base Model

The process started with adapting an existing grid model of Denmark’s transmission grid, imported from PSS/E, into PowerFactory. All DK1 grid components were removed, the only exceptions being fictitious border nodes and HVDC connections linking to neighboring regions/countries, since they represented interfaces of power exchange.

Datasets for the DK2 grid components and their parameters were provided in PSS/E and Excel format by the report’s supervisor. The PSS/E format was not compatible with PowerFactory, and data conversion was performed to transfer the DK2 grid parameters from PSS/E to PowerFactory. When validating the imported component data in PowerFactory, some of the grid parameters did not align with those in the datasets. Hence, many of the parameters of the DK2 components required adjustments, and Python scripts were implemented to automate the process. The scripts matched PowerFactory component parameters with their corresponding data in Excel. After conversion and validation, the base DK2 grid model consisted of 163 busbars.

4.1.1 Changes in DK2 Generation, Demand & Topology

Four scenarios were created in PowerFactory to vary DK2 grid conditions by modifying the base model and adjusting the generation and demand parameters. The data for all four scenarios can be found in Appendix A. The scenarios model current grid conditions using 2022 as reference, and projected grid conditions for 2050. HVDC links were treated as interconnections, i.e. power exchange with neighbouring grids. Negative HVDC values were treated as power export from DK2 (i.e. load), while positive values were treated as power import into DK2.

4.2 The Nordic56 Model

The Nordic56 (N56) model is a simplified model of the Nordic power system. It consists of 11 bidding zones (BZs) according to Table 4.1 below. The base version of N56 (which was modified for use in this report) has 56 busbars and models the 420 and 300 kV transmission network in Sweden, Norway, Finland and Denmark.

Table 4.1: Bidding zones in the N56.

Bidding Zones in N56			
Norway	Sweden	Finland	Denmark
NO1	SE1	FI1	DK2
NO2	SE2	FI2	
NO3	SE3		
NO4	SE4		
NO5			

4.2.1 Changes in Nordic56 Generation, Demand & Topology

N56 models, adjusted for the four scenario conditions in 2022 and 2050, were provided by the report's supervisor. Existing DK2 busbars, as well as load and generation connected to them, were removed entirely from the N56 model, reducing it from 56 to 52 busbars, to allow integration of the detailed DK2 model.

4.3 Integration of DK2 into N56

After performing load flow analysis on the DK2 model and optimizing its parameters, it was integrated into the N56 grid model in PowerFactory. In all four scenario models, the reference machine was changed from the combined heat and power plant Avedøreverket in DK2 to the nuclear power plant Oskarshamn in SE3.

Two 132 kV busbars and two 400 kV busbars were added to N56 and connected to the 8500 MALMO busbar. The N56 model has a base voltage of 420 kV, whereas the DK2 model has a base voltage of 400 kV. To handle this mismatch in base voltages, fictitious 420/400 kV transformers with very low short circuit impedance were added. Data for the border transformers between DK2 and SE4 can be found in Appendix D. The 132 and 400 kV busbars were then connected to the respective border terminals in the DK2 grid through 8 km long cables; this represented the Öresund connection between the bidding areas DK2 and SE4.

It must be noted that the 420/400 kV border transformers between DK2 and SE4 in this model is not an accurate representation of reality. There are, according to the knowledge of this report's authors, no transformers involved in directly linking DK2

and SE4 at the highest base voltages. As such, in this model the 420/400 kV transformers introduce artificial impedance between the BZs, but they are nonetheless strictly necessary due to the differences in nominal transmission voltages between the modeled grids.

4.3.1 Aggregated BESS & EV Battery Implementation in DK2 & N56

Three battery storage devices, representing a zonal aggregation of BESS and EV batteries, were connected to central busbars in SE3, SE4 and DK2. Data for the aggregated BESS/EV units (henceforth simply referred to as BESS) in DK2, SE3 and SE4 can be found in table B.1 in appendix B. The values for the 2022 BESS units were chosen to represent the BESS capacity for that year [26], while the 2050 values were dimensioned according to the current TSO requirement for total Nordic FCR capacity (2050 MW).

The capacity for each BZ was a deliberate compromise between regional demand and market efficiency. Based strictly on demand statistics, SE3 and SE4 would have had an even larger share of BESS, but since energy prices are usually higher in SE4 and DK2, it is likely that battery operators would place a higher proportion of BESS in these areas to exploit the higher profit margins in the local energy markets.

Each battery was connected to a 33 kV busbar, which was then connected to a 132 kV busbar through a 132/33 kV transformer, and then finally connected to a 400 kV busbar (DK2) and 420 kV busbars (SE3 and SE4). A power factor of 0.95 was chosen for the aggregated BESS units across all scenarios to comply with ENTSO-E's minimum reactive power capability for Nordic BESS [27].

No dynamic models for state of charge (SOC) behavior were implemented in the BESS units, given this study's focus on steady-state analysis. However, to allow charging, the minimum active power limits were set as negative of the maximum active power capacity (e.g., the SE3 BESS has an operational range of -820 to 820 MW). The BESS units are therefore assumed to be ideally available for charging or discharging according to grid needs at each stage of the contingency scenario, an assumption that must be noted as optimistic.

Detailed implementation of frequency bias for BESS/EV is provided in section 4.4.3.

4.4 Modeling of the Contingency Scenario

4.4.1 Model Validation

In order for the load flows to be considered valid, constraints were placed on the voltage magnitudes (p.u) and phase angles. The constraints were defined as a voltage magnitude between 0.95 – 1.05 p.u. and a phase angle of $\pm 30^\circ$; these constraints are commonly used to ensure stable grid operation.

To meet these constraints, Static VAR Systems (SVS) were used to determine the values for each additional shunt, to either absorb or produce additional reactive power for voltage regulation. An SVS is a voltage regulating component that maintains a certain fixed setpoint of voltage in per unit value, by injecting or absorbing reactive power. The SVS components were then replaced with fixed shunts in the updated model afterwards, to prevent automatic adjustments of reactive power during contingency analysis, which allows the effects of the events to be evaluated without the compensations for the disturbance. Additionally, parallel lines were also implemented in each scenario to decrease reactance, thereby reducing excessive phase angle differences.

For future scenarios with added generation and demand, the MVA capacities of the DK2 transformer and the rated current of the transmission lines were increased to prevent overloading and angle instability.

4.4.2 Grid Loading Condition Scenarios

As mentioned in section 4.1.1, four main scenarios were created in order to simulate different loading conditions in the Nordic grid. To model RES generation, high wind generation was chosen as the common factor among the scenarios. In addition, each main scenario had 3 sub-scenarios modeling different hydro and BESS FCR participation, in order to capture potential differences in power flow and grid steady-state behavior depending on FCR characteristics. In all, this resulted in 12 different contingency simulations.

4.4.3 FCR Frequency Bias for Sub-Scenarios

The projected BESS participation in FCR market in 2050 was assumed to be significantly larger than today. As a result, the BESS/EV capacity was modeled as non-distinguishing between FCR-N and FCR-D. This was accomplished by adjusting the primary frequency bias for BESS/EV in relation to the bias for hydro using Eq. 4.1 below:

$$\text{Primary Frequency Bias} = B = \frac{\Delta P}{\Delta f} \quad (4.1)$$

ΔP_{FCR-N} in the Nordic grid is 600 MW, and ΔP_{FCR-D} is 1450 MW. As such, ΔP_{FCR} is 2050 MW in total. The Δf_{FCR-N} is ± 0.1 Hz and Δf_{FCR-D} is ± 0.4 Hz.

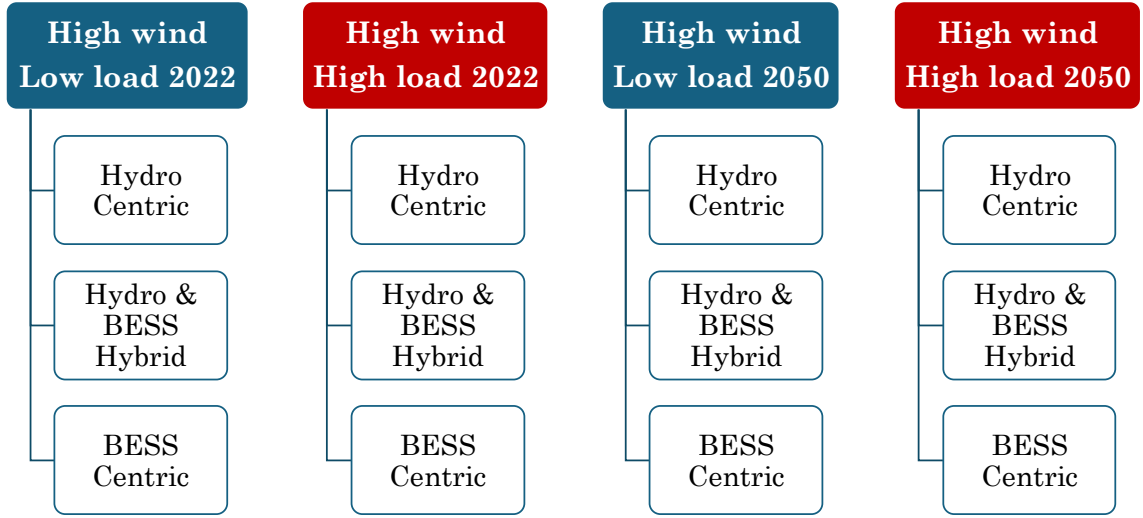


Figure 4.1: The 4 main scenarios with each sub-scenario.

As such, B_{total} for FCR-N and FCR-D in the Nordic region can be derived as:

$$B_{total} = \frac{P_{FCR-N} + P_{FCR-D}}{\Delta f_{FCR-N} + \Delta f_{FCR-D}} = \frac{2050}{0.5} = 4100 \text{ MW/Hz} \quad (4.2)$$

B_{total} was then distributed in the different sub-scenarios according to table 4.2. In the BESS-centric sub-scenario, it was decided to keep some frequency bias for hydro to retain a valid and realistic FCR response. The argument for this decision is hydro's historically dominant role in the Nordic FCR response, the fact that BESS are considered Limited Energy Resources (LERs), and retaining a realistic operational baseline. A power system relying on 100% BESS FCR is not realistic and carries risk of exhausting the FCR [28]. The hydro-centric scenario had no frequency bias allocation for BESS, making BESS contribute zero FCR.

Table 4.2: K values for hydro and BESS/EV in the different sub-scenarios.

Hydro-Centric	Hydro/BESS Hybrid	BESS-Centric
$K_{FCR}^H = 3606 \text{ MW/Hz}$	$K_{FCR}^H = 2050 \text{ MW/Hz}$	$K_{FCR}^H = 10 \text{ MW/Hz}$
$K_{FCR}^{BESS} = 0 \text{ MW/Hz}$	$K_{FCR}^{BESS} = 2050 \text{ MW/Hz}$	$K_{FCR}^{BESS} = 4100 \text{ MW/Hz}$

K_{FCR}^{BESS} was distributed among the three BESS units in proportion to their capacity, across the hydro/BESS hybrid and BESS-centric sub-scenarios. Table ?? shows the individual K values for BESS units in SE3, SE4 and DK2 for each sub-scenario.

For the hydro-centric case in HWLL 2022, the BESS units were given a small total frequency bias of 494 MW/Hz to compensate for insufficient FCR from hydro since hydro's spare capacity in that scenario was below 2050 MW, i.e. the required capacity for FCR. The frequency bias was distributed among the BESS units according to their capacity.

Table 4.3: Individual K values for BESS/EV in the HWHL 2022, HWLL 2050 and HWHL 2050 sub-scenarios.

Hydro-Centric	Hydro/BESS Hybrid	BESS-Centric
$K_{FCR}^{BESS,SE3} = 0$ MW/Hz	$K_{FCR}^{BESS,SE3} = 820$ MW/Hz	$K_{FCR}^{BESS,SE3} = 1160$ MW/Hz
$K_{FCR}^{BESS,SE4} = 0$ MW/Hz	$K_{FCR}^{BESS,SE4} = 717.5$ MW/Hz	$K_{FCR}^{BESS,SE4} = 1015$ MW/Hz
$K_{FCR}^{BESS,DK2} = 0$ MW/Hz	$K_{FCR}^{BESS,DK2} = 512.5$ MW/Hz	$K_{FCR}^{BESS,DK2} = 725$ MW/Hz

Table 4.4: Individual K values for BESS/EV in the HWLL 2022 scenario.

Hydro-Centric	Hydro/BESS Hybrid	BESS-Centric
$K_{FCR}^{BESS,SE3} = 239.5$ MW/Hz	$K_{FCR}^{BESS,SE3} = 820$ MW/Hz	$K_{FCR}^{BESS,SE3} = 1160$ MW/Hz
$K_{FCR}^{BESS,SE4} = 239.5$ MW/Hz	$K_{FCR}^{BESS,SE4} = 717.5$ MW/Hz	$K_{FCR}^{BESS,SE4} = 1015$ MW/Hz
$K_{FCR}^{BESS,DK2} = 15$ MW/Hz	$K_{FCR}^{BESS,DK2} = 512.5$ MW/Hz	$K_{FCR}^{BESS,DK2} = 725$ MW/Hz

4.4.4 Contingency Scenarios

The contingency scenarios, detailed in Fig. 4.2, were chosen to mirror the mechanisms of the contingencies described in chapter 3. The aim was to simulate the cascading loss of wind generation due to control system failure after an N-1 reference incident, defined as the loss of an Oskarshamn generation unit in SE3. Since there was a large variance in absolute generation and demand between each scenario, the N-1 incident varied in magnitude accordingly. It was also decided to trip close to 2000 MW of power in each contingency to significantly stress the Nordic FCRs' dimensioning limit of 2050 MW.

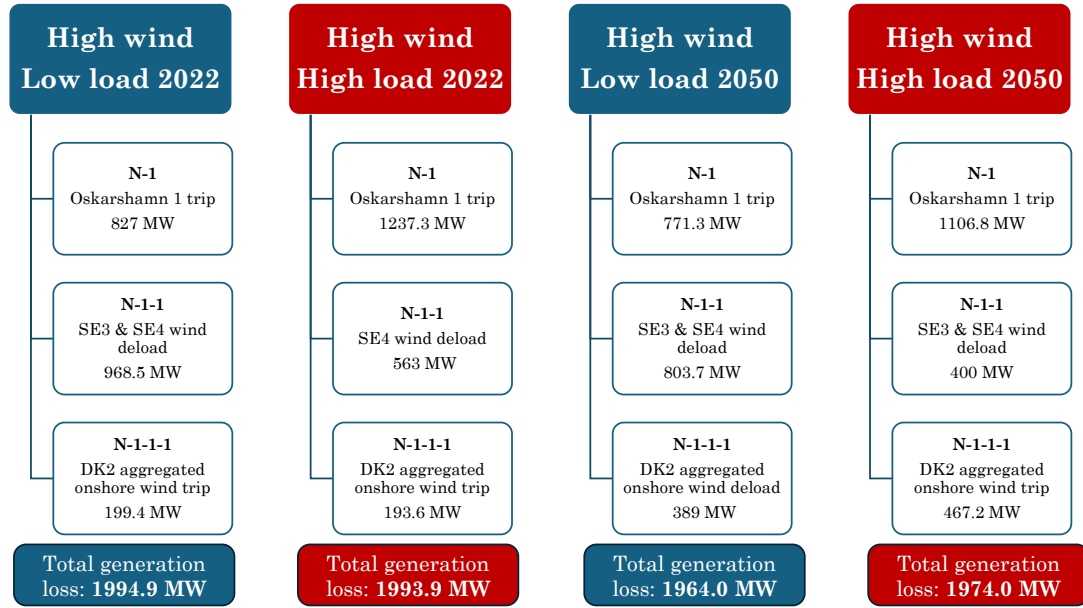


Figure 4.2: Flow chart of the individual cascading contingencies for each scenario.

Trial simulations were performed to assess the load flow convergence of each scenario. During this process, the high wind and high load scenario of 2022 (HWHL 2022) had convergence issues. It was decided to only deload an SE4 wind turbine in the HWHL scenario compared to the HWLL scenario, to achieve a stable system.

The individual scenarios were implemented by combining sequential load flow analysis with Python scripting, according to Fig. 4.3. Tripping of generators was accomplished by setting them as *out of service*, which in the PowerFactory load flow environment is equivalent to a switching event. Deloading of wind turbines was done through scaling down their active and reactive power output before initializing the subsequent load flow.

The load flow solver was set to calculate according to primary control, which allows station controllers to oversee the response of their assigned generators. This normally lessens the load on the slack bus when solving the load flow, and simulates the actual load-sharing behavior of generators both in steady-state and during contingencies. However, in this report the absolute majority of generators had station

controllers set to voltage control according to their individual reactive power. This means that they only participated in local voltage control at their specified buses (through modulating their reactive power output), and not in frequency control and power re-balancing. Only hydro plants and BESS units with assigned frequency bias participated in power re-balancing along with the slack bus, which itself was controlled by a power-frequency controller.

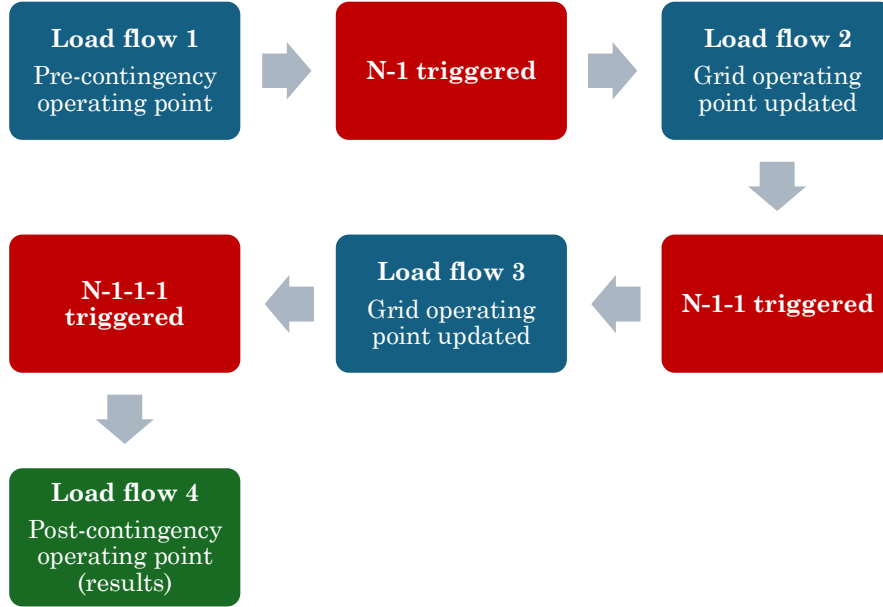


Figure 4.3: Flow chart of the Python script implementation for the cascading contingency event in PowerFactory, which was used across all scenarios.

4.4.5 A Note on Load Flow Convergence

To ensure numerical stability across all simulations, scenario-specific load flow adjustments had to be implemented. The BESS/hydro hybrid and BESS-centric HWLL 2050 scenarios, as well as the BESS-centric HWHL 2050 scenario, required the explicit designation of 3300 OSKARSHAMN in N56 as reference bus to achieve load flow convergence. However, the load flow was still configured to solve these scenarios according to primary control balancing, so the impact of these adjustments were likely negligible.

5

Results

In this chapter, the following results are presented: DK2 model evaluation, scenario-specific power flows between BZs, voltages, phase angles and FCR performance.

5.1 Evaluation of the Updated DK2 Model

Fig. 5.1 shows the voltage and phase angle distribution of the busbars in the base DK2 model after performing load flow analysis. Several busbars violated the voltage operational limits of 0.95–1.05 p.u.

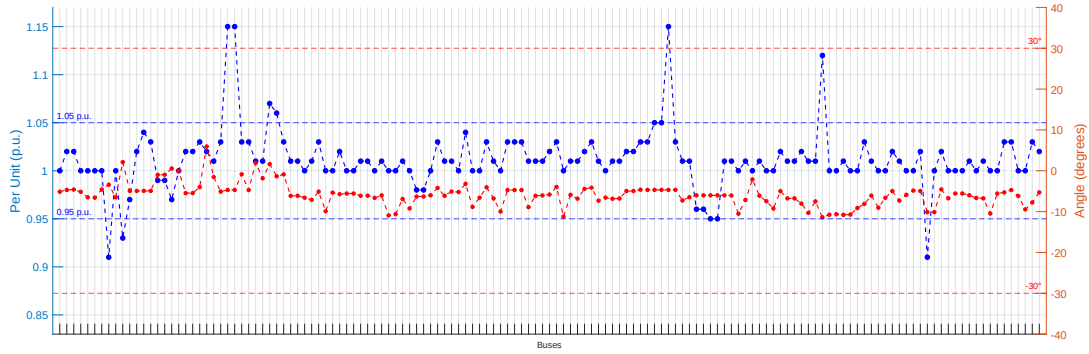


Figure 5.1: Voltage and phase angles across DK2 busbars before shunt compensation.

To correct the violations, additional shunts were added to the buses with voltage levels outside the limits. After adjustments, the load flow analysis showed that all busbars had voltages within operational limits, showcased in Fig. 5.2.

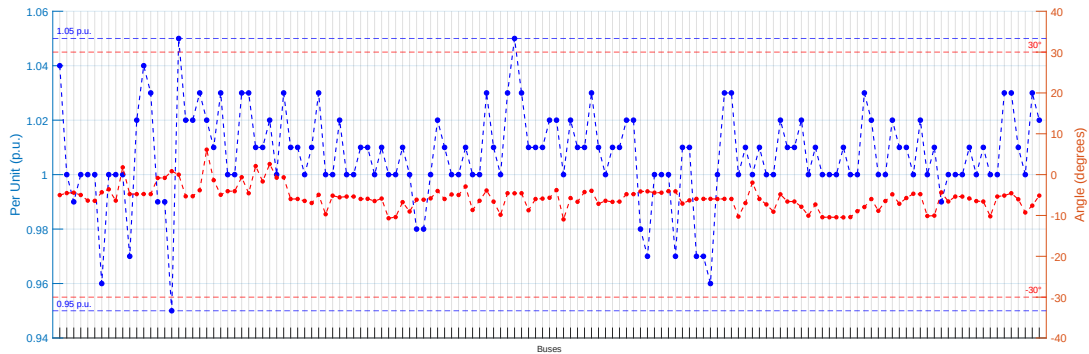


Figure 5.2: Voltage and phase angles across DK2 busbars after shunt compensation.

5.2 Power Flows between Bidding Zones

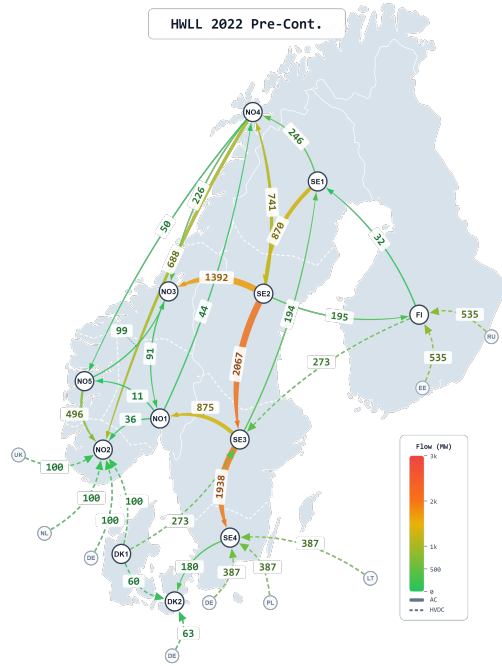
Figures 5.3a to 5.6d present the pre- and post-contingency power flows between BZs for current and future scenarios. For each scenario, panel (a) illustrates the pre-contingency flows, while the subsequent sub-figures show the change in post-contingency flows compared to pre-contingency flows in MW, labeling the five largest variations. Note that some transfers (such as the direct exchange between NO4 and NO1) are simulation-specific abstractions rather than real power flows, as these BZs share no physical border.

The most significant change observed between current and future power flows is that inter-area flows in the Nordic power system shift dramatically. This change is likely correlated to the shift in generation centers. Traditionally, generation has been concentrated in the northern parts of the NPS, while load centers have been concentrated in the south. This places stress on the transmission corridors from north to south, and from west to east, especially during contingencies when hydro needs to increase power and transport it south. In this situation (which mirrors current power transmission realities in 2026) localized FCR in the form of BESS is expected to relieve north-to-south transmission corridors and decrease the need for reserved hydropower.

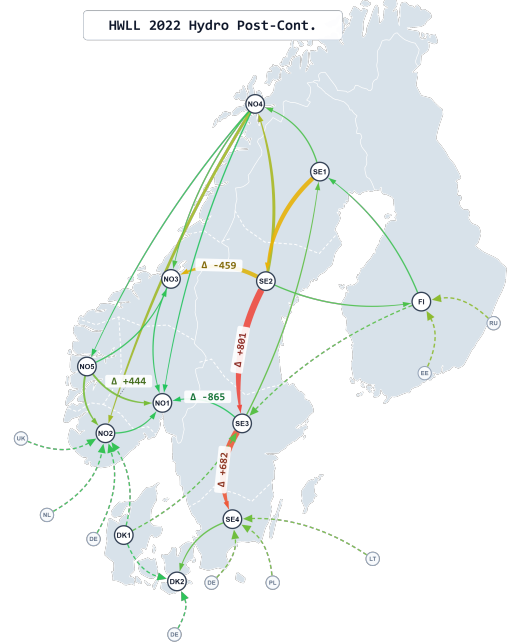
However, a change in power flow dynamics was observed in the future scenarios. Finland has a significant increase in overall output power in both scenarios, as well as DK2 in the 2050 scenarios. Norway and Sweden become load centers. This marks a change from the current north-to-south transmission burden, where the future power flows are marked by an east-to-west transmission corridor instead. A lot of power thus flows from east to west, as well as a south-to-north flow. Since BESS assets are located in the southern areas, their FCR participation increases the power transfer to northern BZs during disturbances, which leads to higher losses. On the contrary, hydro FCR (which comes from the northern part of the NPS) reduces the total net flow in future disturbances. This could in part explain the repeated negative angle violations observed in Norway in table 5.2 and 5.3. This shift in power flow directions leads to a possible decrease in benefit of localized FCR in the southern NPS for the specific contingency analysed in this project report.

Google’s Gemini 3.1 Pro was used for creating a power flow visualizer tool, which enabled the creation of the power flow figures in this section.

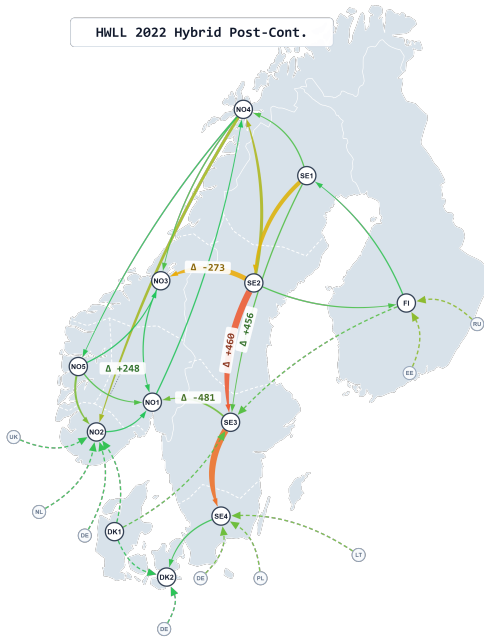
5. Results



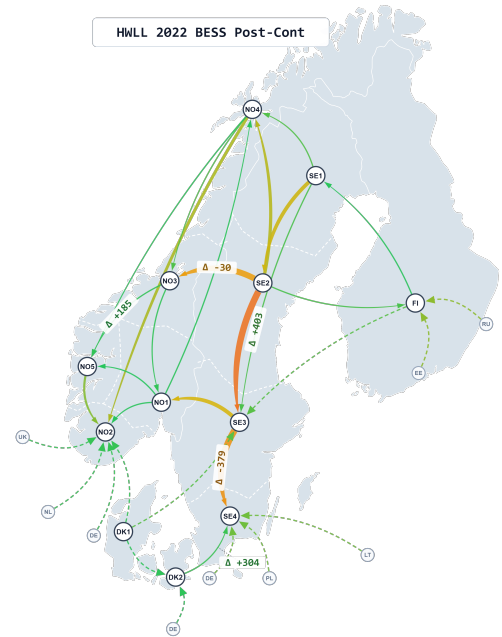
(a) Pre-contingency base case.



(b) Post-contingency: Hydro-Centric.

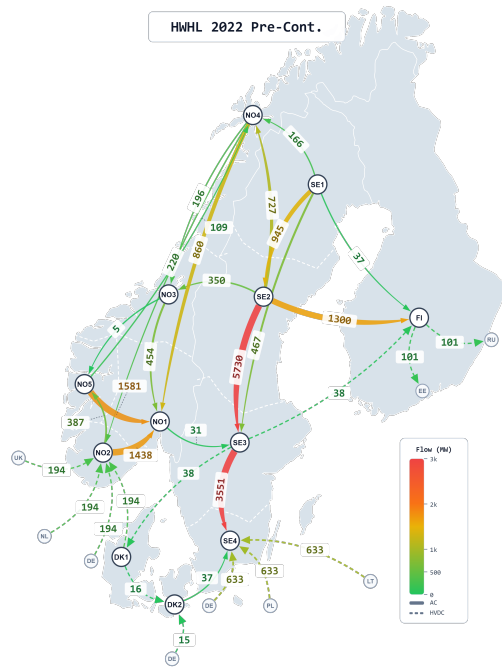


(c) Post-contingency: Hydro/BESS Hybrid.

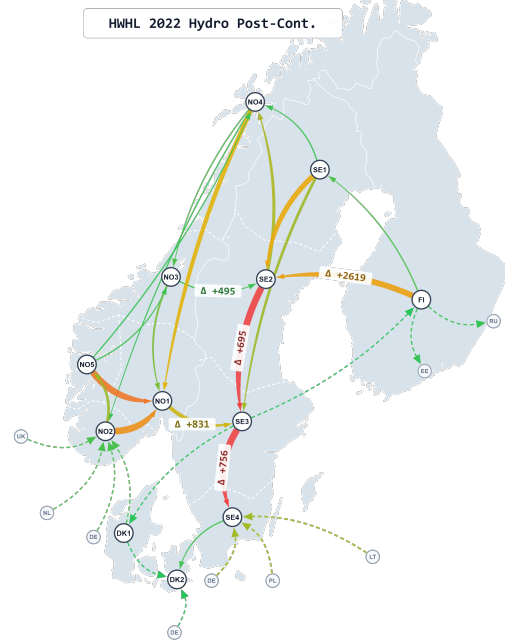


(d) Post-contingency: BESS-Centric.

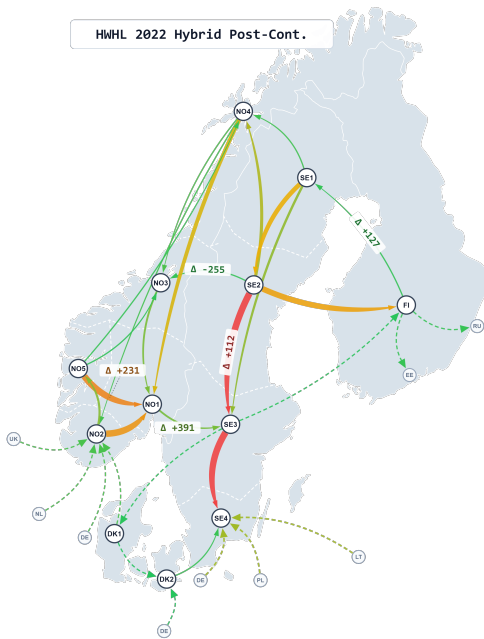
Figure 5.3: Comparison of pre-contingency power flow (a) and post-contingency power flow across hydro-centric, hydro/BESS hybrid and BESS-centric scenarios (HWLL 2022).



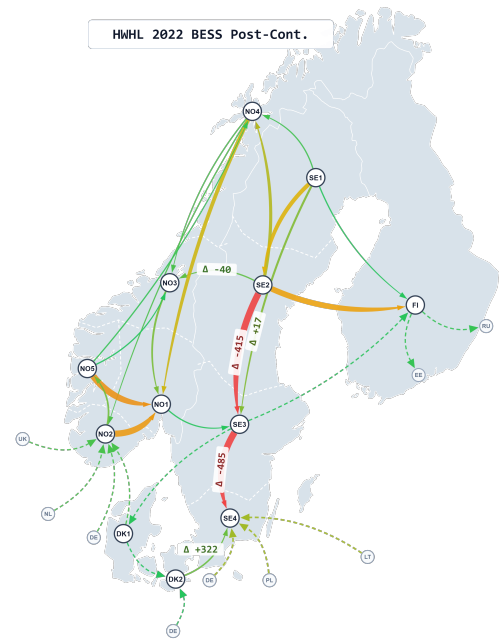
(a) Pre-contingency base case.



(b) Post-contingency: Hydro-Centric.

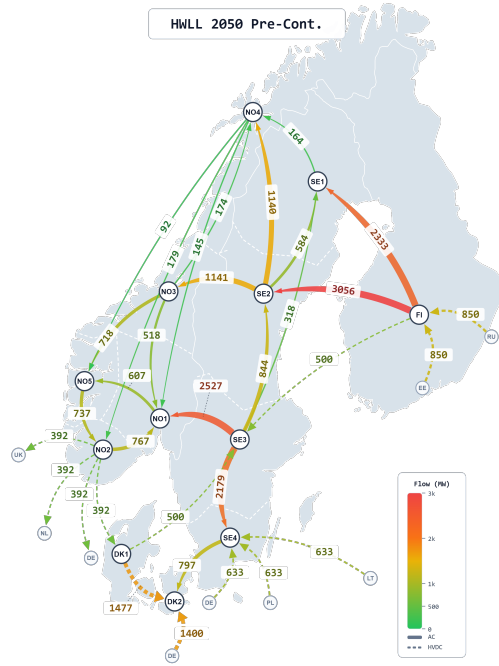


(c) Post-contingency: Hydro/BESS Hybrid.

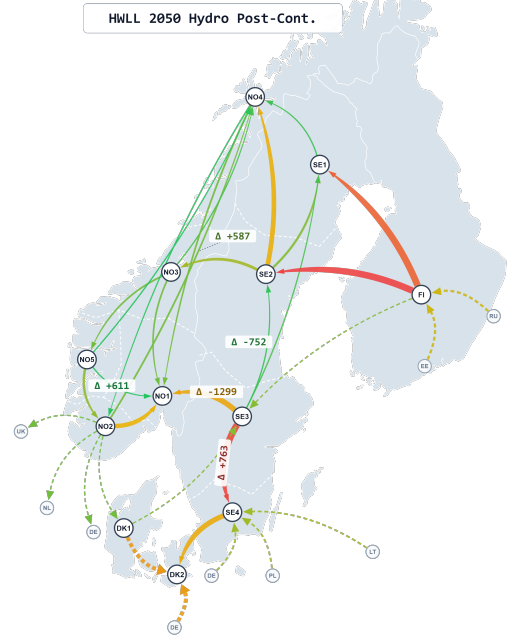


(d) Post-contingency: BESS-Centric.

Figure 5.4: Comparison of HWHL 2050 pre-contingency power flow (a) and post-contingency power flow across hydro-centric, hydro/BESS hybrid and BESS-centric scenarios (HWHL 2050).



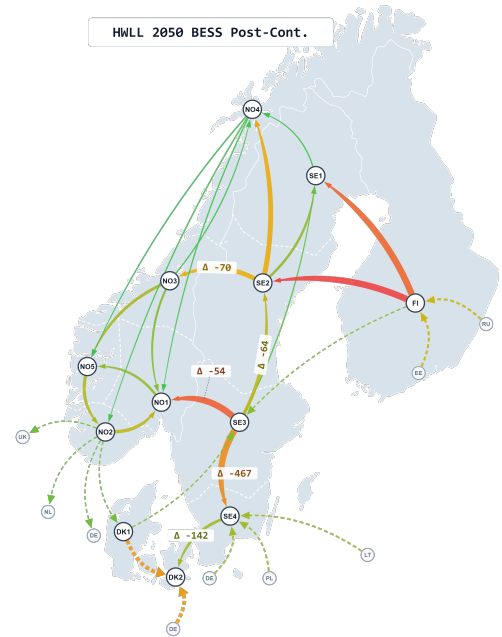
(a) Pre-contingency base case.



(b) Post-contingency: Hydro-Centric.

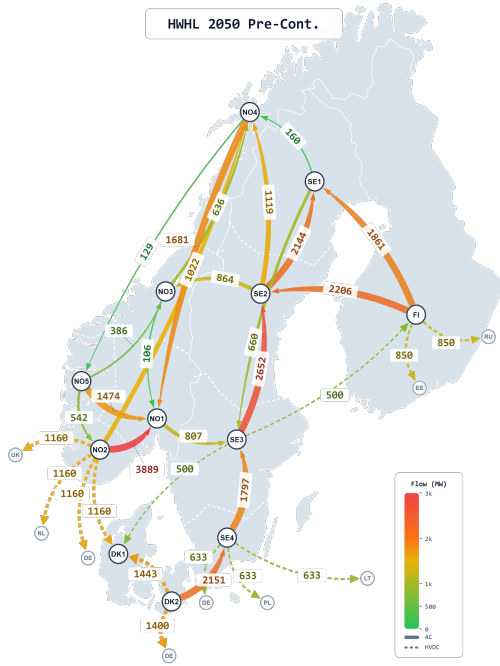


(c) Post-contingency: Hydro/BESS Hybrid.



(d) Post-contingency: BESS-Centric.

Figure 5.5: Comparison of pre-contingency power flow (a) and post-contingency power flow across hydro-centric, hydro/BESS hybrid and BESS-centric scenarios (HWLL 2022).



(a) Pre-contingency base case.



(b) Post-contingency: Hydro-Centric.



(c) Post-contingency: Hydro/BESS Hybrid.



(d) Post-contingency: BESS-Centric.

Figure 5.6: Comparison of HWWL 2050 pre-contingency power flow (a) and post-contingency power flow across hydro-centric, hydro/BESS hybrid and BESS-centric scenarios (HWWL 2050).

5.3 Voltage & Phase Angle Simulation Results

Figures E.1–H.6, found in appendices E–H, detail the pre- and post-contingency DK2 and N56 voltage magnitudes and phase angles for all scenarios. Each vertical line represents a busbar, each dot represents the busbar’s pre-contingency operating point, and each cross represents the busbar’s post-contingency operating point.

5.3.1 HWHL 2022

Out of all the given scenarios, only the HWHL 2022 resulted in voltage violations, which are the DK2-connected bus and the corresponding fictitious bus.

Table 5.1: Overvoltages in HWHL 2022 scenarios.

Location/BZ	Voltage (p.u.) δ (°)			
	Pre-Contingency	Post-Contingency		
		Hydro Centric	Hybrid BESS/Hydro	BESS
DK2 bus in N56-grid 400 kV/SE4	1.1	1.1	1.1	1.1
Fictitious bus 400 kV/DK2	1.08	1.08	1.08	1.08

One possible reason for the overvoltage is the use of the fictitious DK2 bus and SE4 transformer, which interacted differently with the conditions represented in HWHL 2022. While these settings might have worked for the remaining scenarios, the base parameters and conditions for HWHL 2022 seems to be more sensitive to these components. As they do not correspond to actual components in reality, they may have affected the calculated voltage levels. Due to the project time constraints, an investigation of this effect was not pursued.

5.3.2 HWLL 2050

Table 5.2 details the phase angle violations in the HWLL 2050 scenarios. The lower limit violations in Norway are consistent with the pattern of large power export from east to west showcased in Fig. 5.3a - 5.3d. When BESS FCR participation increases, DK2 power export increase as well, resulting in upper limit angle violations. This aligns with the reversed power flow pattern, where power flows from south to north instead of the traditional north-to-south direction. As battery’s FCR increases, DK2’s power export increases along with it due to one of the battery installed at DK2.

Table 5.2: Busbar phase angle comparison between HWLL 2050 scenarios. **Red color** denotes angle violation.

Location/BZ	Phase Angle δ ($^{\circ}$)			
	Pre-Contingency	Post-Contingency		
		Hydro Centric	Hybrid BESS/Hydro	BESS
Rødsand 2 132 kV/DK2	11.2	24.95	33.88	41.98
Rødsand 1 132 kV/DK2	10.8	24.56	33.49	41.58
Radsted 9 kV/DK2	7.98	21.75	30.68	38.78
Radsted 132 kV/DK2	7.96	21.73	30.67	38.76
Rødby 132 kV/DK2	7.53	20.68	29.61	37.7
Femern 132 kV/DK	7	20.12	29.05	37.14
Idestrup 132 kV/DK	5.68	19.79	28.73	36.82
Eskilstrup 132 kV/DK2	5.6	19.71	28.64	36.74
Vestlolland 132 kV/DK2	5.01	18.08	27	35.09
Orehoved 132 kV/DK2	3.76	18.03	26.96	35.06
Masnedøverket 132 kV/DK2	2.76	17.21	26.14	34.24
Kriegers Flak C 150 kV/DK2	-0.02	17.09	25.89	33.88
Germany 150 kV Kriegers Flak/DK2	-0.03	17.08	25.88	33.87
Germany 150 kV Kriegers Flak/DK2	-0.03	17.08	25.88	33.87
Kriegers Flak B 232 kV/DK2	-0.05	17.06	25.86	33.85
Kriegers Flak C 232 kV/DK2	-0.05	17.06	25.86	33.85
Kriegers Flak C 0.4 kV/DK2	-0.23	16.88	25.68	33.67
Kriegers Flak C 10 kV/DK2	-0.23	16.88	25.68	33.67
Kriegers Flak A 232 kV/DK2	-0.36	16.75	25.55	33.54
Stigsnæsværket 132 kV/DK2	2.33	16.05	24.98	33.07
Stigsnæsværket B2 18 kV/DK2	2.28	16	24.93	33.02
Blangslev 132 kV/DK2	-0.96	13.94	22.88	30.98
Blåfalli 300 kV/NO2	-39.79	-4.21	-4.92	-5.55
Bergen 300 kV/NO5	-34.13	0	0	0
Aurland 420 kV/NO5	-32.21	-0.06	0.94	1.82
Oslo 2 300 kV/NO2	-32.13	-2.75	-0.37	1.76
Oslo 1 300 kV/NO1	-32.08	-1.12	0.48	1.91
Kaggefoss 420 kV/NO1	-31	-0.23	1.46	2.97
Eidfjord 420 kV/NO5	-30.99	-0.1	1.53	2.99
Sylling 420 kV/NO1	-30.96	-0.69	1.25	2.99
Hagafoss 420 kV/NO4	-30.95	-0.19	1.51	3.02
Geilo 420 kV/NO5	-30.82	-0.11	1.61	3.15
Skien 420 kV/NO1	-30.67	-1.55	0.96	3.21
Stavanger 300 kV/NO2	-30.41	0.3	2.02	3.56
5999 300 kV/NO4	-30.39	0.93	2.34	3.61
Kvillidal 300 kV/NO2	-30.39	0.92	2.34	3.61
Sandefjord 420 kV/NO2	-30.37	-0.12	1.83	3.57
NO2 NSL 300 kV/NO2	-30.33	0.99	2.41	3.68
BESS-SE3, 33 kV/SE3	0	17.6	30.05	41.46
BESS-SE3, 132 kV/SE3	0	17.6	27.31	36.12
Forsmark 420 kV/SE3	1.14	19.15	26.53	33.19
Dannebo HVDC 420 kV/SE3	0.97	18.98	26.36	33.02
Oskarshamn 420 kV/SE3	0	17.6	25.34	32.33
Jarpestromme 420 kV/SE2	-0.68	18.57	25.42	31.58
Hogasen 420 kV/SE2	-2.02	17.8	24.39	30.32

5.3.3 HWHL 2050

Table 5.3 details the phase angle violations that occurred in the HWHL 2050 scenarios.

Table 5.3: Busbar phase angle comparison between HWHL 2050 scenarios. Red color denotes angle violation.

Location/BZ	Phase Angle δ (°)			
	Pre-Contingency	Post-Contingency		
		Hydro Centric	Hybrid BESS/Hydro	BESS
Rødsand 2 132 kV/DK2	35.96	13.06	21.96	29.39
Rødsand 1 132 kV/DK2	35.49	12.59	21.49	28.92
Radsted 9 kV/DK2	32.21	9.33	18.22	25.65
Radsted 132 kV/DK2	32.21	9.33	18.22	25.65
Rødby 132 kV/DK2	31.64	8.05	16.95	24.37
Femern 132 kV/DK	31.11	7.32	16.22	23.64
Røssåga 420 kV/NO4	-28.7	-41.23	-36.26	-32.15
Røssåga NEW 300 kV/NO4	-26.46	-38.99	-34.04	-29.93
Ofoten 420 kV/NO4	-24.73	-37.81	-32.57	-28.22
Ajaure 300 kV/SE2	-24.81	-37.53	-32.46	-28.25
Porjus 420 kV/SE1	-22.39	-35.77	-30.37	-25.9
Helsinki 420 kV/FI1	-21.48	-34.52	-29.28	-24.95
Vyborg HVDC 420 kV/FI1	-21.19	-34.23	-28.99	-24.66
Estlink HVDC 420 kV/FI1	-21.19	-34.23	-28.99	-24.66
Grundfors 420 kV/SE2	-20.91	-33.83	-28.65	-24.35
Oulu 420 kV/FI1	-17.82	-30.86	-25.62	-21.29

All of the DK2 substations are located in or around Lolland, which is situated on the southern edge of DK2, except Stignæsværket and Masnedøværket which are located on Sjælland. Rødsand 1 and 2 are offshore wind farms. It can be concluded, given the violations, that the southern-most part of DK2 was under heavy strain pre-contingency.

The majority of substations with post-contingency angle violations are situated in northern Norway and Sweden. When FCR is provided mainly by hydropower, which is located in the northern part of the NPS, the angles decreased even further compared to the pre-contingency values. This indicates increased power transfer through the northern part of the grid. With both hydro and BESS participating in FCR, the angles are reduced. However, in the BESS-centric case the post-contingency angles are closer to the pre-contingency values. This is primarily due to a larger FCR response from BESS located in the southern part of Sweden, as well as DK2. Hence, less additional power needs to be transferred from the northern part of the NPS which in turn resulted in smaller angle deviations in the BESS-centric case.

5.4 FCR Performance & Loss Comparison

Fig. 5.7 details the scenario-specific FCR contribution of the individual BESS in DK2, SE3 and SE4, along with the hydro response.

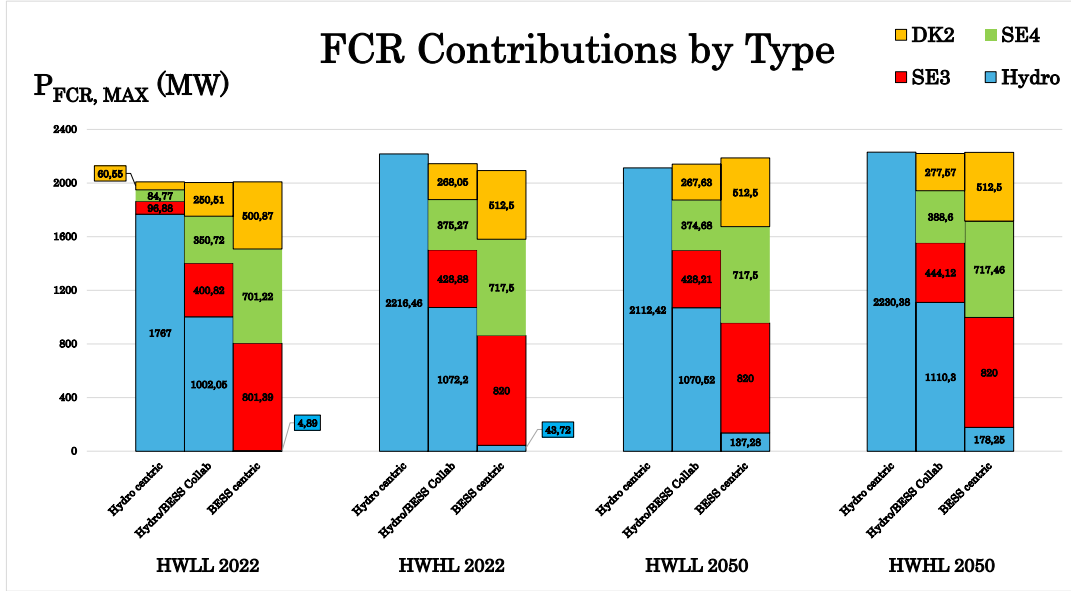


Figure 5.7: Total post-contingency FCR contribution by type for each scenario.

Table 5.4 shows the post-contingency reserve power by type in each sub-scenario. The main finding is that for hybrid BESS/hydro scenarios (except HWLL 2022), BESS does not saturate, while in the BESS-centric scenarios they do. This is an indication that BESS reached its limit and could not provide any additional power.

For consistency with the hydro-centric case where hydro FCR capacity was 2050 MW, total BESS FCR capacity (i.e. the accumulated capacity of BESS in DK2, SE4 and SE3) was set to 2050 MW in the hybrid hydro/BESS and BESS-centric scenarios. However, the post-contingency results showed that BESS reached its limit and could not provide any further power. During that stage of simulation, the authors of this report did not consider increasing the capacity of BESS. Since hydro had non-zero frequency bias in the hydro/BESS collaboration and BESS-centric scenarios, there was FCR support from hydropower in both scenarios that compensated for the saturated BESS.

As can be seen in table 5.4, hydro reserve power increased alongside increased BESS FCR participation.

5. Results

Table 5.4: Scenario-Specific Post-Contingency Power Reserves (in MW) across Sub-Scenarios

Scenario	Sub-scenario	Hydro	DK2 BESS	SE4 BESS	SE3 BESS
HWLL 2022	Hydro-centric	35.7	452	632.7	723.1
	Hybrid BESS/Hydro	801.5	262	366.8	419.2
	BESS-centric	1798.7	11.6	16.3	18.6
HWHL 2022	Hydro-centric	2497.6	512.5	717.5	820
	Hybrid BESS/Hydro	3641.8	244.5	342.2	391.1
	BESS-centric	4670.3	0	0	0
HWLL 2050	Hydro-centric	6751.3	512.5	717.5	820
	Hybrid BESS/Hydro	7787.1	244.9	342.8	391.8
	BESS-centric	8720.4	0	0	0
HWHL 2050	Hydro-centric	408.6	512.5	717.5	820
	Hybrid BESS/Hydro	1528.6	234.9	328.9	375.9
	BESS-centric	2460.7	0	0	0

Fig. 5.8 shows the pre- and post-contingency losses (in MW) for each sub-scenario compared to pre-contingency losses.

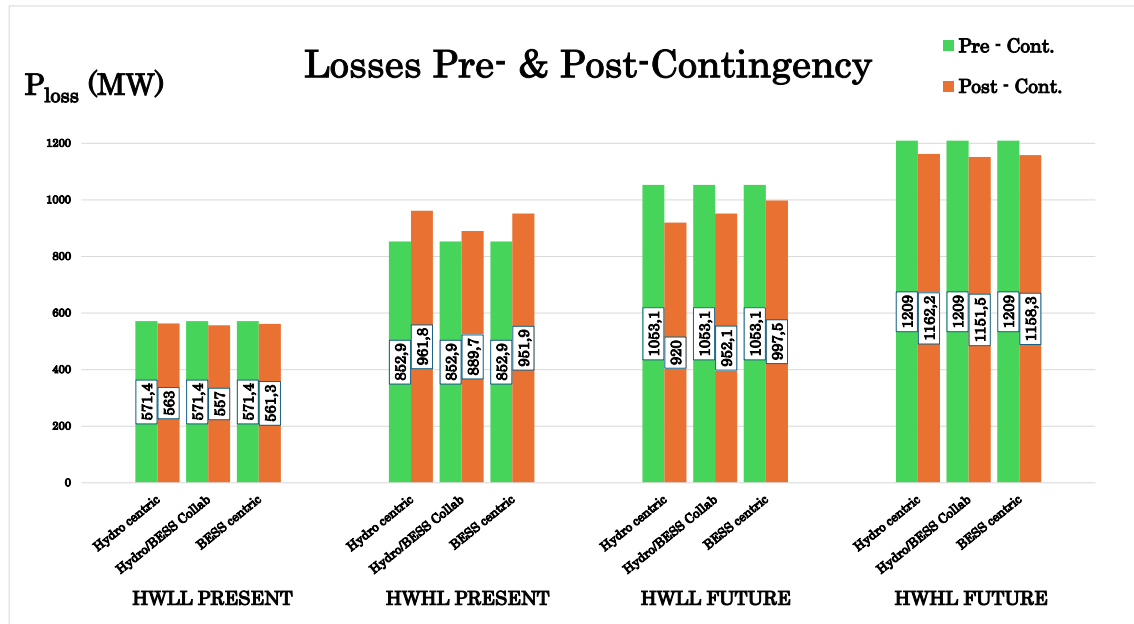


Figure 5.8: Losses for each scenario in MW.

Table 5.5 shows the loss data for each sub-scenario. A normalized efficiency coefficient ρ_{loss} was calculated for each scenario using Eq. 5.1. ρ_{loss} represents the net grid loss impact/MW of lost generation.

$$\rho_{loss} = \frac{P_{loss,post} - P_{loss,pre}}{P_{contingency}} \times 100 = \frac{\Delta P_{loss}}{P_{contingency}} \times 100 \quad (5.1)$$

A positive coefficient indicates a network efficiency penalty, where the post-contingency power redistribution increases the electrical distance between generation and load. Conversely, a negative coefficient indicates a network optimization effect, where the FCR response relieves transmission bottlenecks.

Table 5.5: Comparison of Scenario-Specific Grid Losses and Normalized Efficiency Coefficients

Scenario	$P_{loss, pre}$ (MW)	$P_{loss, post}$ (MW)	ΔP_{loss} (MW)	$P_{contingency}$ (MW)	Loss Coefficient (ρ_{loss})
HWHL 2022 BESS-Centric	852.9	951.9	+99	1993.9	+4.97
HWHL 2050 BESS-Centric	1207.6	1158.3	-49.3	1974.0	-2.50
HWHL 2022 Hybrid BESS/Hydro	852.9	889.7	+36.8	1993.9	+1.85
HWHL 2050 Hybrid BESS/Hydro	1207.6	1151.5	-56.1	1974.0	-2.84
HWHL 2022 Hydro-Centric	852.9	961.8	+108.9	1993.9	+5.46
HWHL 2050 Hydro-Centric	1207.6	1162.2	-45.4	1974.0	-2.30
HWLL 2022 BESS-Centric	571.4	561.3	-10.1	1994.9	-0.51
HWLL 2050 BESS-Centric	1053.1	997.5	-55.6	1964.0	-2.83
HWLL 2022 Hybrid BESS/Hydro	571.4	557	-14.4	1994.9	-0.72
HWLL 2050 Hybrid BESS/Hydro	1053.1	952.1	-101	1964.0	-5.14
HWLL 2022 Hydro-Centric	571.4	563	-8.4	1994.9	-0.42
HWLL 2050 Hydro-Centric	1053.1	920	-133.1	1964.0	-6.78

Based on ρ_{loss} comparison for each scenario in table 5.5, BESS-based FCR has a larger beneficial impact on efficiency during heavy loading conditions compared to low loading.

For HWHL 2050, HWLL 2022 and HWHL 2022 scenarios, BESS participation in FCR correlates to efficiency gains. There is also a marked pattern of an optimal level of BESS FCR participation, since the hybrid BESS/hydro characteristic shows the highest efficiency gains compared to hydro-centric or BESS-centric scenarios. In the HWHL 2050 scenario, the south-to-north and east-to-west transmission corridors are already stressed due to high demand, and the efficiency gains may be explained by localized BESS FCR injecting power closer to where the contingencies happened. The same is true for the 2022 scenarios, albeit in their case the the southern BESS assets are decreasing the strain on the north-to-south transmission corridors.

For HWLL 2050, hydro involvement correlates with larger efficiency gains, and BESS has a negative impact on efficiency in proportion to its FCR participation. This may be due to the shift in east-to-west and south-to-north transmission corridors in the future. Because BESS FCR is located in the south, their FCR power injection forces more energy to travel from south to north during a contingency. This increases the power transfer and subsequently increases network line losses, which becomes more

apparent in low load conditions.

For the future scenarios, with south-to-north power transfer, post-contingency losses were lower compared to pre-contingency due to the tripping of power generation in SE3, SE4 and DK2. Since the southern part of the NPS acted as a generation center and the northern part a demand center, the contingency actually decreased the amount of power transported across the network. This resulted in lower post-contingency losses compared to the 2022 scenarios.

6

Discussion

6.1 Verification of the Model

The operational limit is 0.95–1.05 voltage p.u. and a δ of $\pm 30^\circ$ is used to evaluate if the simulation model is reasonable. Three of the pre-contingency cases (HWHL 2022, HWLL 2050 and HWHL 2050) were in violation of the operational limits from the start. These base case violations point to possible underlying problems in the balancing of generation and demand (and other unknown factors) of the models. The operational violations were probably also exacerbated by non-optimal reactive power compensation in the DK2 model, since all of the load flows – despite converging – resulted in multiple warnings of maximum and minimum reactive power limits reached.

The single voltage violation found in the HWHL 2022 scenario was likely caused by one of the border transformers between DK2 and SE4. The transformers were assigned a very low short-circuit voltage U_k of 0.5% to represent an ideal transformer between the areas. During the high loading scenario, the increased active and reactive power exchange are higher due to the low impedance path offered by the transformer, which increased busbar's voltage level. The same behavior did not occur in the HWLL 2022 case, which could be due to the lower current and power exchange environment.

Another possible issue is integrating a non-optimized higher-resolution model (DK2/163 busbars) with an optimized lower-resolution model (N56/52 busbars). In this case, non-optimized means that the DK2 model converged with around 25–30 warnings of reactive limits reached, while the N56 model converged with significantly fewer such warnings. When integrating the non-optimized DK2 model with the optimized N56 model, the authors of this report suspect that the Newton-Raphson solver encounters mathematical difficulties when trying to solve the load flow in each scenario.

Another error source are the 420/400 kV and 420/132 kV transformers that enabled the connection between DK2 and SE4 in this report's model. These are necessary modeling artifacts for this report: in reality the Öresund high-voltage cables connect DK2 and SE4 directly without the need for transformers. In this report, the transformers introduce artificial impedance between DK2 and SE4, and as such may have influenced the resulting load flows and their ability to converge.

6.2 Accuracy of the Simulation Method & Scenario Implementation

The most significant weakness of the DK2 model in this report is its lack of dynamic behavior. The original intention was to capture not only the voltage and phase angles during a contingency, but also variables affected by the dynamic and transient behavior of a power system under stress. These factors include RoCoF, frequency nadir, and load shedding. Due to time constraints during the project, the decision was made to limit the scope to static contingency modelling.

Because of this limited scope, generators and loads were not assigned dynamic models. Dynamic models would likely have enabled more realistic contingency responses. For example, assigning governor, voltage regulation and power-frequency control models for a synchronous generator would have allowed frequency plots to be captured in PowerFactory. Due to these limitations, it is likely that transient operational limit violations occurring between each N-X stage were missed, since only steady-state data was captured.

In addition, PowerFactory allows the implementation of remedial action schemes, which adds another dimension of dynamic behavior by allowing generators and loads to disconnect/reconnect based on defined frequency and voltage levels. This would likely impact simulation behavior, compared to this report's deterministic contingency implementation: hard-coded disconnections and de-loading of wind turbines in a certain sequence. Remedial action schemes would have allowed a more realistic power system response to the contingency.

It is also important to recognize that no scenario resulted in a blackout, despite the contingencies' size and high RES grids' sensitivity to disturbances. Whether this is a result of the Nordic grid's resilience, or a feature of the simplified modeling choices of this report, is a matter to investigate in future studies.

6.3 FCR Performance

The decision to use 2050 MW to dimension the FCR in the 2050 scenarios is an approximation. It is likely that FCR requirements will increase in the coming 24 years, and the viability of applying current FCR requirements on future scenarios is at best tenuous. Nonetheless, for a system the size of the Nordic grid, a contingency resulting in the sudden generation loss of 2000 MW goes beyond current N-1 criterion.

As detailed in Fig. 5.7, localized FCR in the form of BESS close to a disturbance may alleviate transmission capacity that would otherwise be reserved to provide FCR. The reduced burden on transmission capacity scales with BESS participation rate in FCR. The results in table 5.1 demonstrate that the efficiency of the FCR response is highly sensitive to the grid's power flow profile. Under heavy load conditions (HWHL 2050), a BESS-centric or hybrid BESS/hydro response provides

the highest efficiency gain by injecting power close to load centers and minimizing transmission line loading. Conversely, under low-load (HWLL 2050) a hydro-centric response offers superior efficiency by physically rebalancing the transmission system, exemplified by the reversal of power flow between DK2 and SE4 pre- and post-contingency. Overall, it was expected to see a greater benefit of localized BESS assets in the southern NPS, but since future power flows will likely change compared to today's, BESS' effect on unlocking transmission capacity was not as pronounced when placed in the south, which was potentially caused by the change in power flow from east-to-west.

The unlocked transmission capacity enabled by BESS FCR participation – under certain loading conditions – can be used in the energy market, which could potentially lead to energy price reductions. This is of great value in the Nordic grid, which is characterized by long transmission corridors and electrical bottle-necks. Given the tentative results of this study, optimal future BESS placement remains to be determined.

6.4 Ethical, Social & Sustainability Considerations

One of the main concerns of battery manufacture (which encompasses ethical, social and sustainability factors) is where the materials come from. Rare earth elements (REEs) and critical minerals, which are essential in the manufacturing of BESS, are linked to geopolitical, environmental and human rights challenges in countries where they are sourced [29]. One of the most important elements in battery manufacturing is cobalt [30], an essential part of many lithium-ion battery technologies. For example, it is highly likely that the BESS modelled in this report would be based on lithium-ions, as they are usually the first choice for ancillary services [31]. Some of the world's largest cobalt and lithium reserves are located in DR Congo, a country long affected by conflict, humanitarian crises and resource exploitation [32].

The EU has implemented regulations to promote European sourcing of BESS materials from manufacturers that comply with human and environmental rights [33], in an effort to reduce the harmful effects on human lives and the environment that REEs mining entails depending on where they are sourced.

In a bid to decrease the European dependence on other countries for REEs, Sweden has begun investigating the exploitation of its own national resources, e.g., the Per Geijer deposit in Kiruna [34]. However, the path to large-scale mining of REEs is long and would also have ethical, social and environmental impacts here. For example, the Per Geijer deposit is on land that is important to the Sámi people and their traditional reindeer herding [35], and mining operations would impact the rights of the Sámi.

Sodium-ion batteries offer a promising alternative to their lithium-ion counterparts. Manufacturing them requires up to 682 times less water [36], which could drastically reduce environmental stress, and sodium itself is far more abundant than

lithium. Also, sodium-ion technology does not require cobalt [37]. However, the main drawback of sodium-ion technology is its lower energy density [36]. Consequently, conducting a cost-benefit analysis for specific applications is essential to determine when sodium can replace lithium, ultimately reducing the ethical and environmental impacts of cobalt and lithium mining.

It can be concluded that to secure a stable and renewable power system with an increased share of BESS, compromises must be made between global climate goals and ethical or environmental costs.

7

Conclusions & Future Work

In this chapter, conclusions based on the results and discussion are presented, along with suggestions for future research focus.

7.1 Conclusions

The aims of this degree project were to review real contingencies, integrate an updated DK2 model into the Nordic power system, and then subject the combined grid to a large contingency to assess whether FCR contribution from BESS may unlock Nordic transmission capacity.

The results indicate that there may be benefits to localizing FCR provision in the Nordic power system, depending on the grid's loading conditions. The most significant result was that for future high loading scenarios, the burden on transmission corridors reduced post-contingency when BESS was involved in the FCR response. There were also indications pointing to an optimal mix of FCR participation between BESS and hydro, since in some cases the hybrid BESS/hydro scenarios offered the largest efficiency gains, compared to the hydro-centric or BESS-centric cases.

These results likely correlate to changes in future power flows compared to current conditions. BESS efficiency gains in the future cases were less pronounced than expected. This indicates that placement of BESS units may be more advantageous in other areas than the southern NPS in the future, given the likely shift in generation centers from north to east and consequent change in transmission congestion.

It was also revealed that in future low loading scenarios, BESS participation decreased the efficiency of transmission. However, in those same scenarios, DK2 imported less power from SE4 when BESS was involved in the FCR response, indicating local alleviation in transmission capacity.

Overall, the findings of this report indicate that, given the geography and power asset distribution of the Nordic countries, local BESS assets may unlock transmission capacity in the grid during future and current high wind and high load conditions, as well as current high wind and low load conditions, but optimal placement and level of involvement remains to be determined. The ethical and environmental impact of current battery technologies must also be taken into account when evaluating large-scale investments in BESS.

7.2 Future Studies

Further research is needed to provide stronger evidence on the potential benefits that local BESS FCR assets may have on Nordic transmission capacity. The next step would be to apply a robust dynamic simulation method and assess transient and steady-state behavior of the DK2 and the Nordic power system during similar contingencies as the ones presented here, to challenge the assumptions and findings of this report. A larger variance of both local BESS capacity and frequency bias allocation would also be interesting to investigate.

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A

DK2 Scenario Data

Table A.1: High wind & low load scenario in DK2 for 2022.

Type	Value (MW)
<i>Generation</i>	
Wind	921
Thermal	117
Gas	27
Solar	0
Other (incl. nuclear, hydro)	0
Total generation	1065
HVDC	−120.5
<i>Demand</i>	
Total demand	1101
<i>Capacity</i>	
Wind	1753
Solar	574
Thermal	163
Gas	38
Total capacity	2568
HVDC	2800

Table A.2: High wind & high load scenario in DK2 for 2022.

Type	Value (MW)
<i>Generation</i>	
Wind	1473
Thermal	857
Gas	114
Solar	0
Other (incl. nuclear, hydro)	0
Total generation	2444
HVDC	−29.5
<i>Demand</i>	
Total demand	2335.4
<i>Capacity</i>	
Wind	1753
Solar	574
Thermal	1190.3
Gas	158.33
Total capacity	3675.6
HVDC	2800

Table A.3: High wind & low load scenario in DK2 for 2050.

Component	Value (MW)
<i>Generation</i>	
Wind	5296
Other (thermal, nuclear, hydro etc.)	0
Total generation	5296
HVDC	−2800
<i>Demand</i>	
Total demand	3028
<i>Capacity</i>	
Wind	6961
Solar	6048
Total capacity	13 009
HVDC	−2800

Table A.4: High wind & high load scenario in DK2 for 2050.

Type	Value (MW)
<i>Generation</i>	
Wind	6055
Solar	279
Other (thermal, nuclear, hydro etc.)	0
Total generation	6334
HVDC	2800
<i>Demand</i>	
Total demand	6685
<i>Capacity</i>	
Wind	6961
Solar	6048
Total capacity	13 009
HVDC	2800

B

BESS Data

Table B.1: DK2, SE3 & SE4 BESS Units

BZ	Capacity (MVA)	Power Factor $\cos\phi$	Substation
DK2	539.5	0.95	Vejleå 132 kV
SE3	863.2	0.95	Oskarshamn 420 kV
SE4	755.3	0.95	Mamlö 420 kV

C

BESS Transformer Data

Table C.1: BESS Transformer Parameters by Region & Year

Scenario	Region	Rating (kV)	Capacity (MVA)	Short-Circuit V_k (%)
2022 & 2050	DK2	132/33	400	5
	SE3	420/132	750	6
		132/33	540	6
	SE4	420/132	750	6
		132/33	540	6

Note: No-load losses and iron losses are 0 kW for all scenarios.

D

DK2/SE4 Border Transformer Data

Table D.1: DK2/SE4 Border Transformers – 2022 Scenario

Rating (kV)	Capacity (MVA)	Short-Circuit V_k (%)
420/132	1000	0.5
420/400	1000	0.5

Note: No-load losses and iron losses are 0 kW.

Table D.2: DK2/SE4 Border Transformers – 2050 Scenario

Rating (kV)	Capacity (MVA)	Short-Circuit V_k (%)
420/132	1500	0.5
420/400	2000	0.5

Note: No-load losses and iron losses are 0 kW.

E

DK2 & N56 Voltage & Angles for HWLL 2022

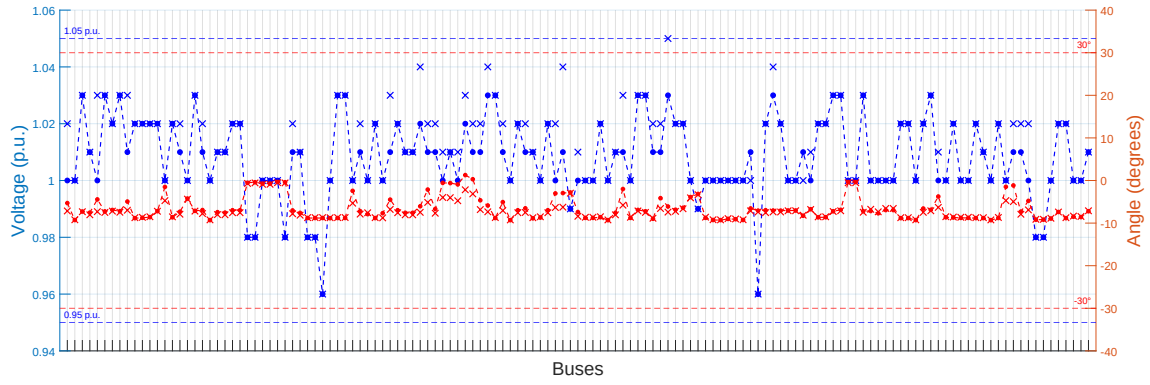


Figure E.1: DK2 Hydro centric sub-scenario.

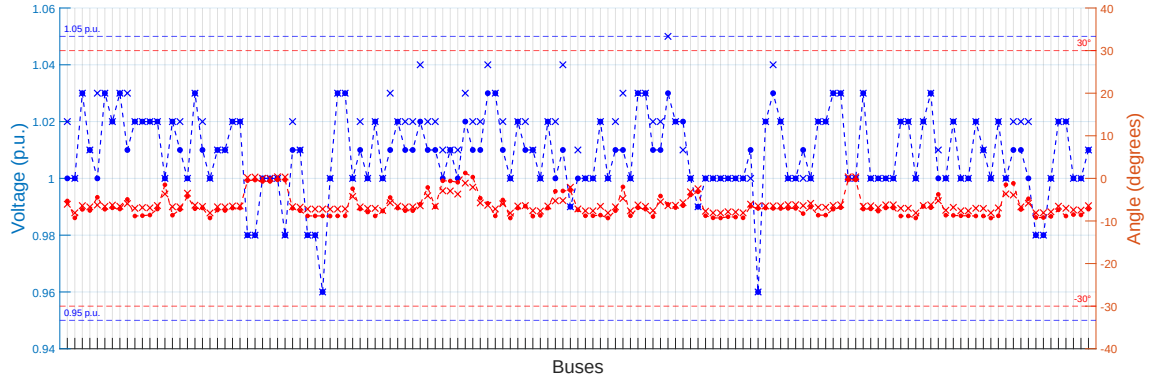


Figure E.2: DK2 Hydro/BESS hybrid sub-scenario.

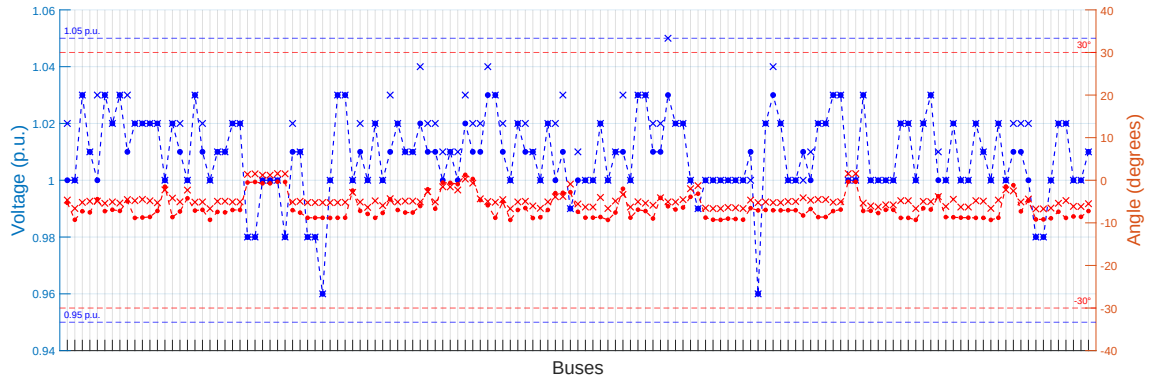


Figure E.3: DK2 BESS centric sub-scenario.

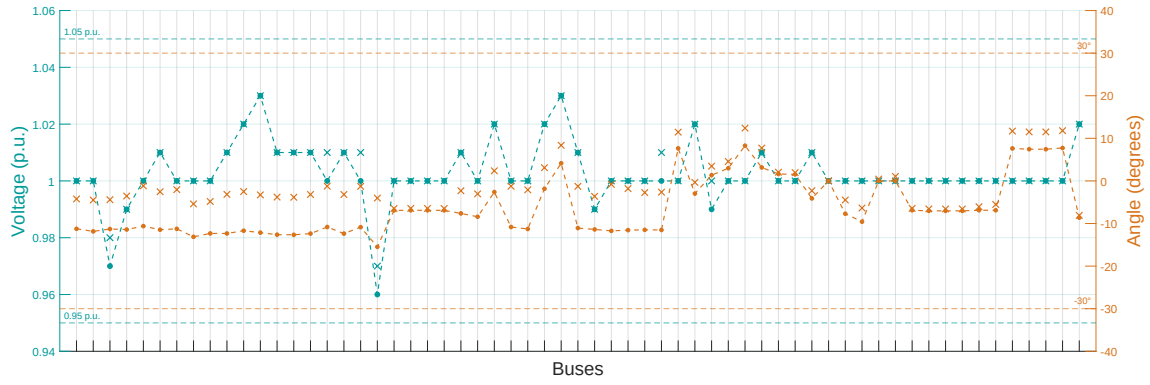


Figure E.4: N56 Hydro centric sub-scenario.

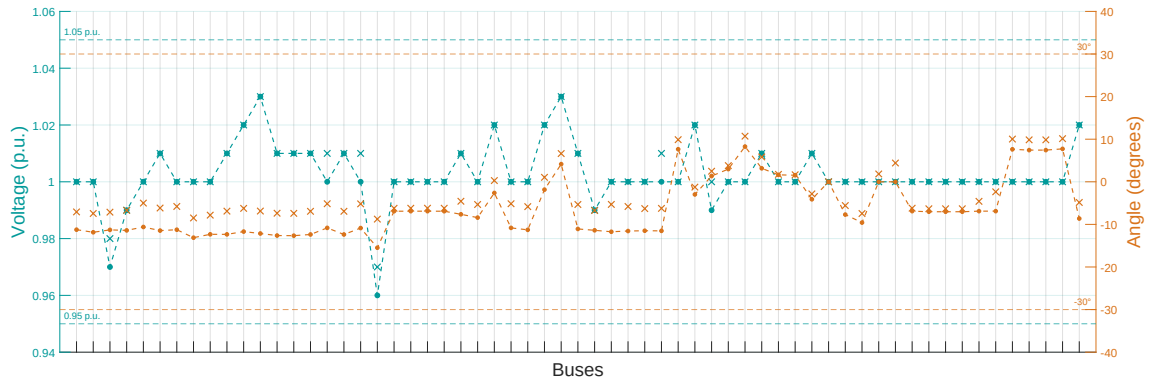


Figure E.5: N56 Hydro/BESS hybrid sub-scenario.

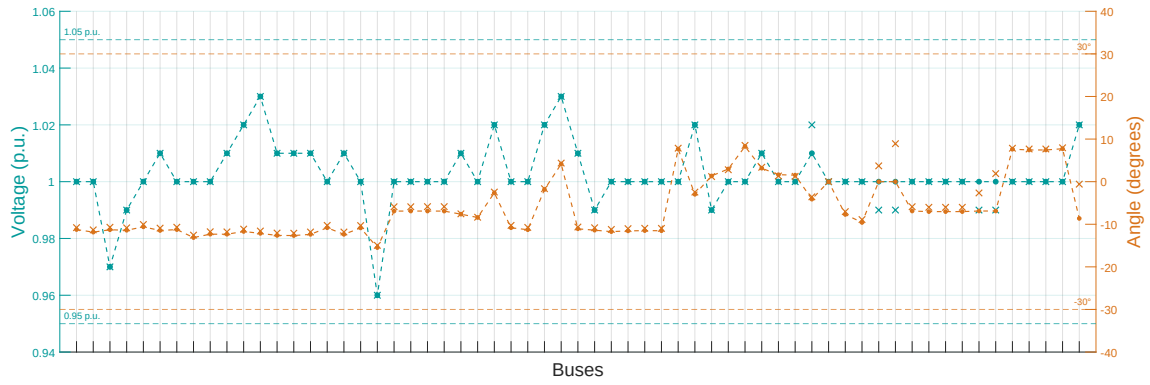


Figure E.6: N56 BESS centric sub-scenario.

F

DK2 & N56 Voltage & Angles for HWHL 2022

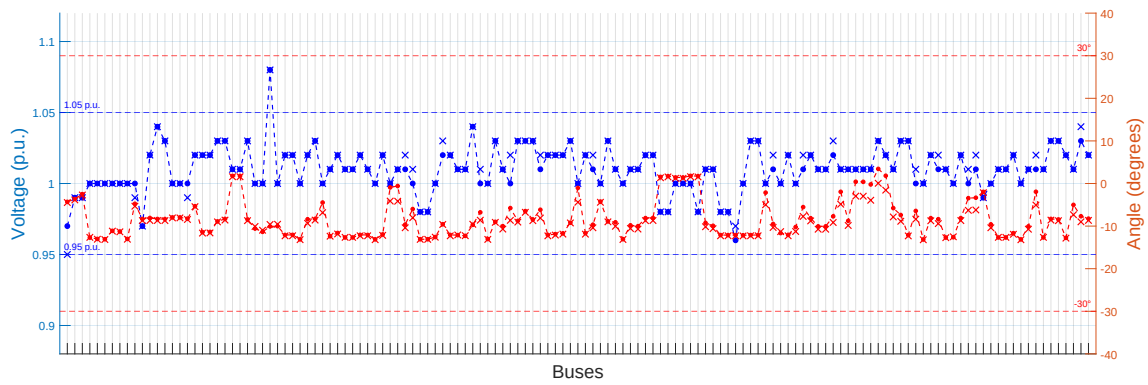


Figure F.1: DK2 Hydro centric sub-scenario.

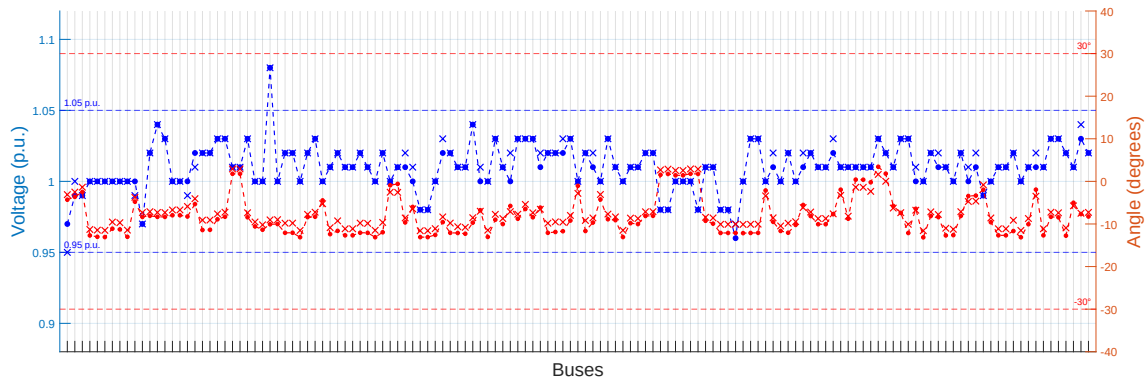


Figure F.2: DK2 Hydro/BESS hybrid sub-scenario.

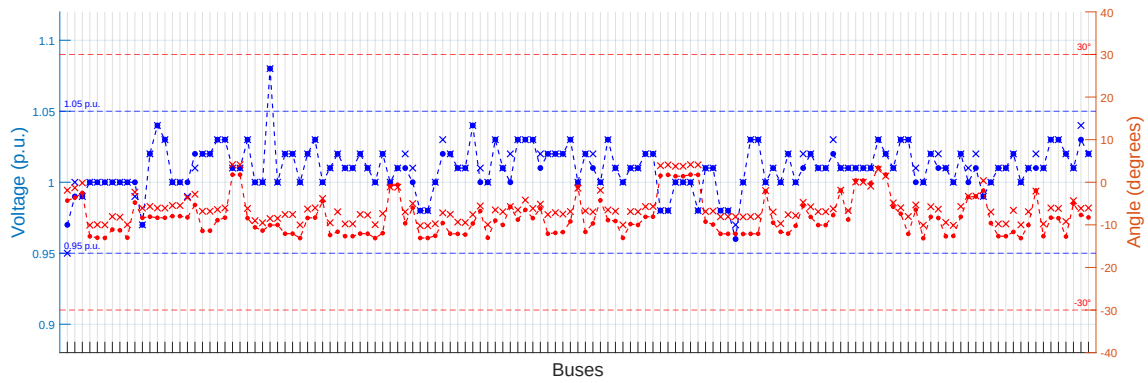


Figure F.3: DK2 BESS centric sub-scenario.

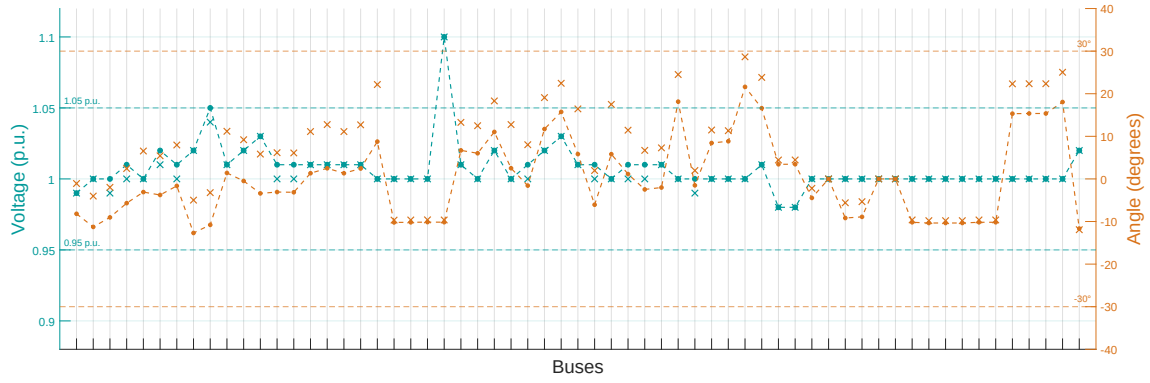


Figure F.4: N56 Hydro centric sub-scenario.

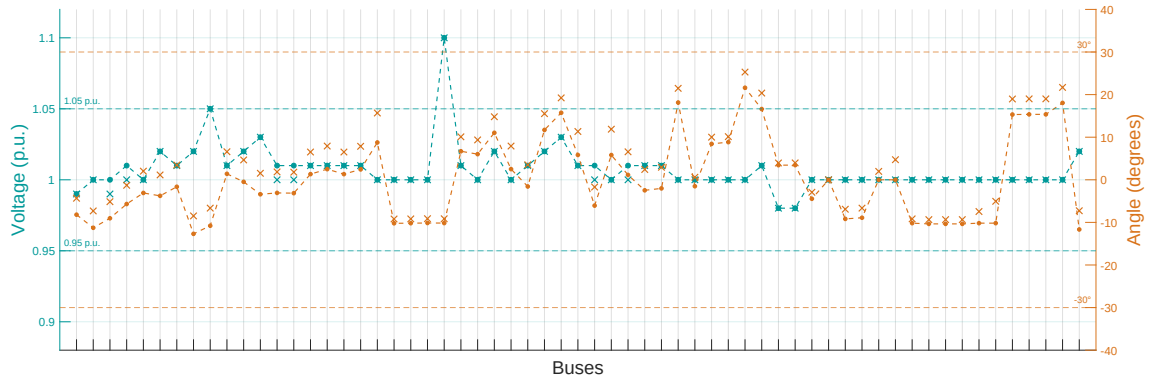


Figure F.5: N56 Hydro/BESS hybrid sub-scenario.

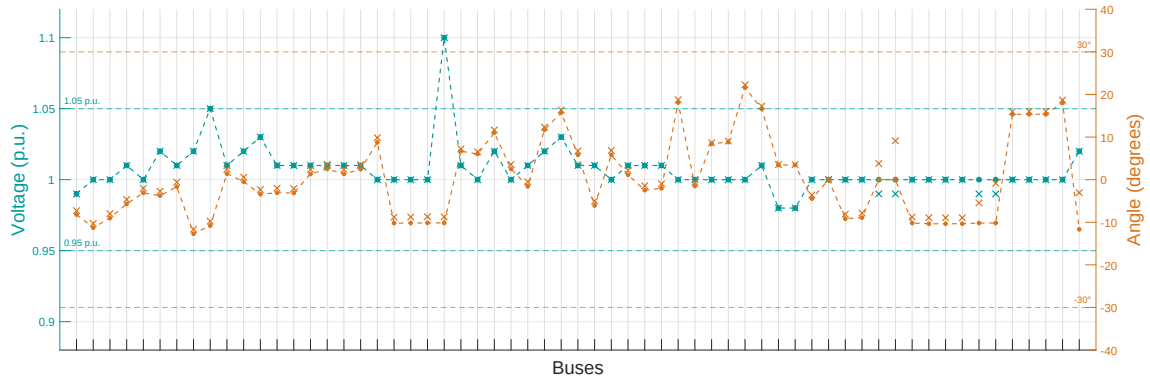


Figure F.6: N56 BESS centric sub-scenario.

G

DK2 & N56 Voltage & Angles for HWLL 2050

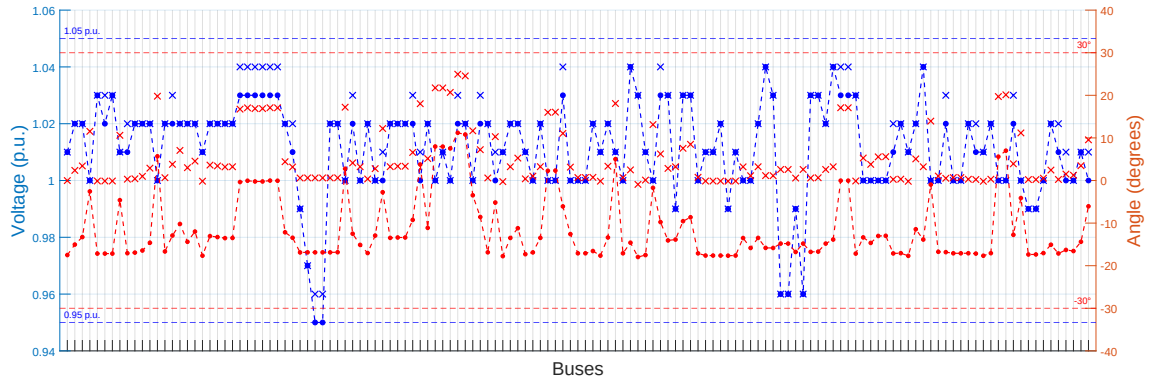


Figure G.1: DK2 Hydro centric sub-scenario.

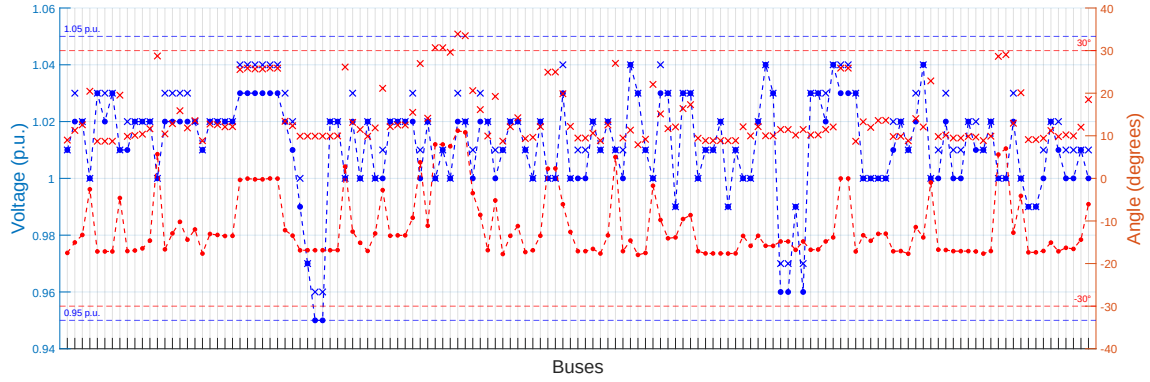


Figure G.2: DK2 Hydro/BESS hybrid sub-scenario.

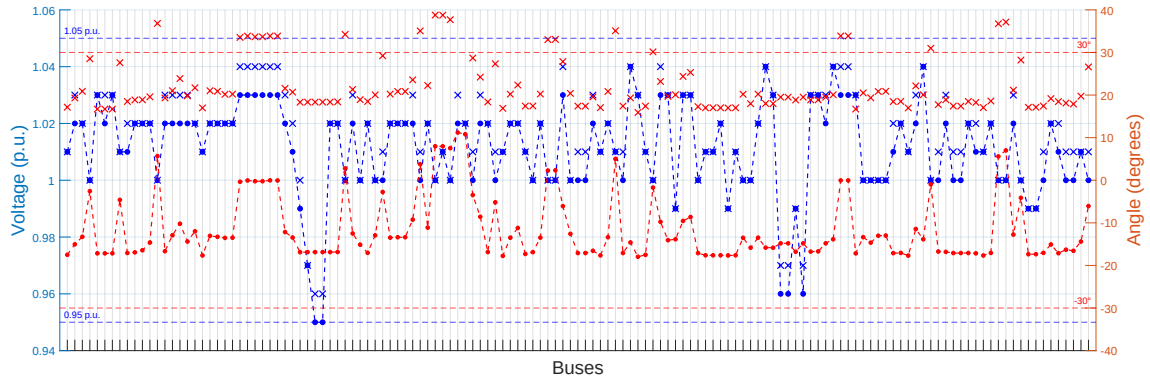


Figure G.3: DK2 BESS centric sub-scenario.

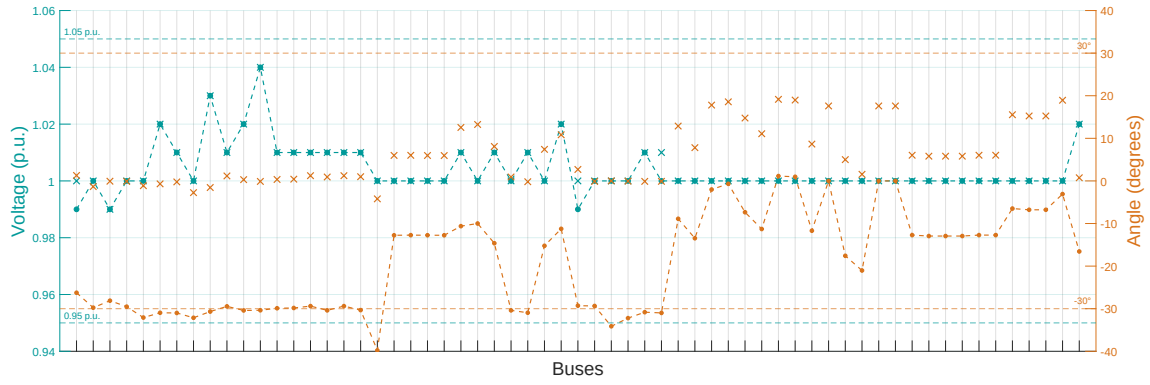


Figure G.4: N56 Hydro centric sub-scenario.

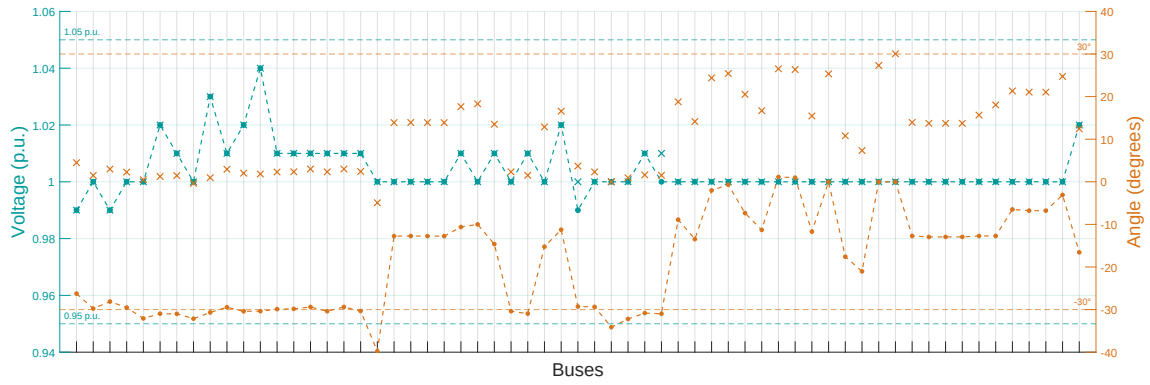


Figure G.5: N56 Hydro/BESS hybrid sub-scenario.

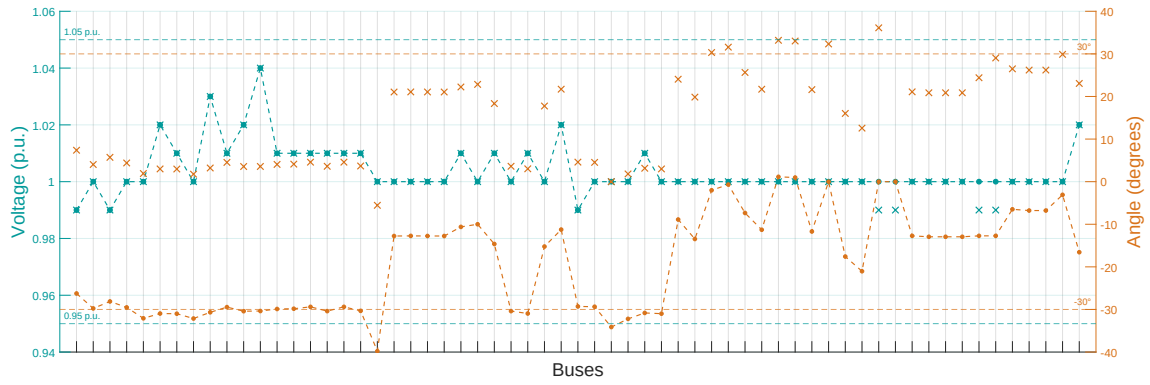


Figure G.6: N56 BESS centric sub-scenario.

H

DK2 & N56 Voltage & Angles for HWHL 2050

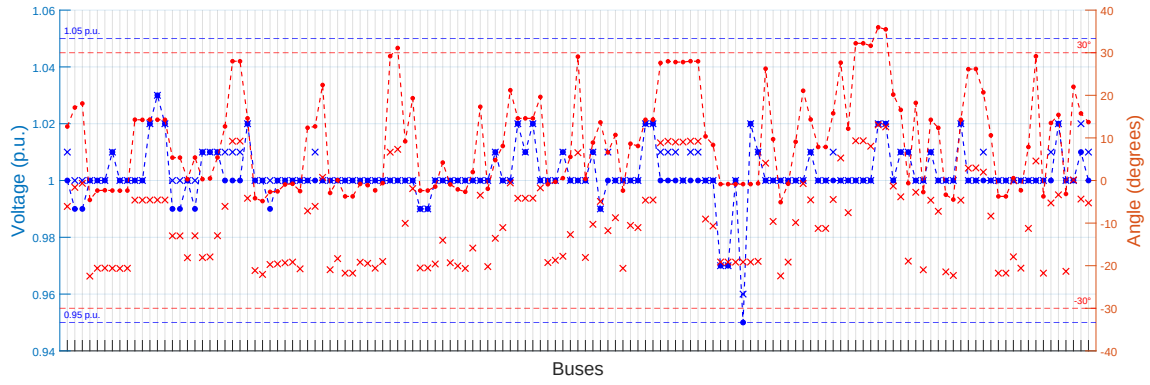


Figure H.1: DK2 Hydro centric sub-scenario.

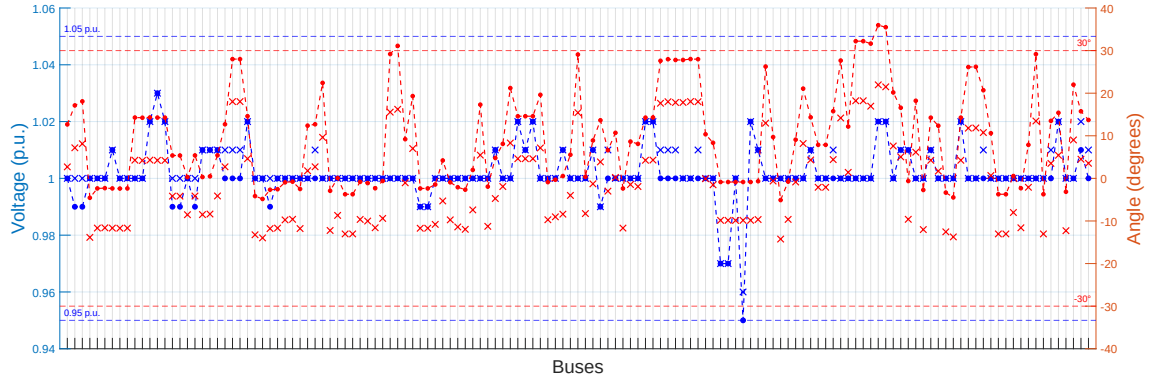


Figure H.2: DK2 Hydro/BESS hybrid sub-scenario.

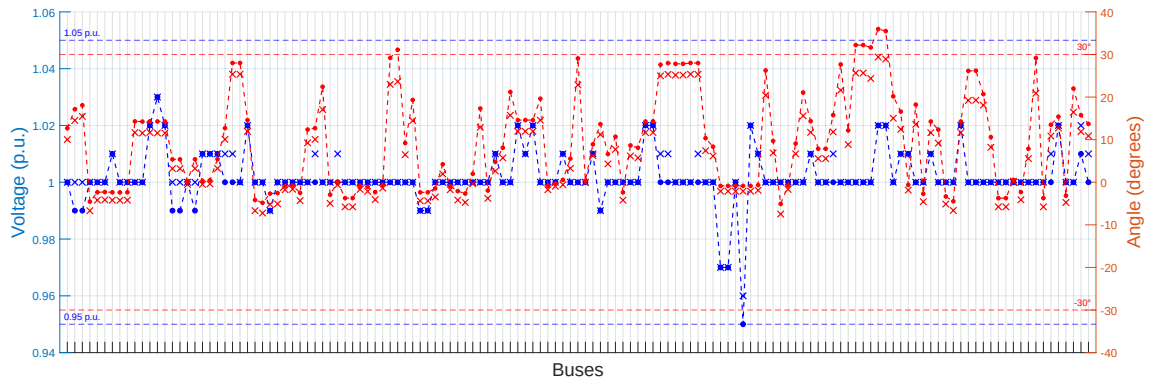


Figure H.3: DK2 BESS centric sub-scenario.

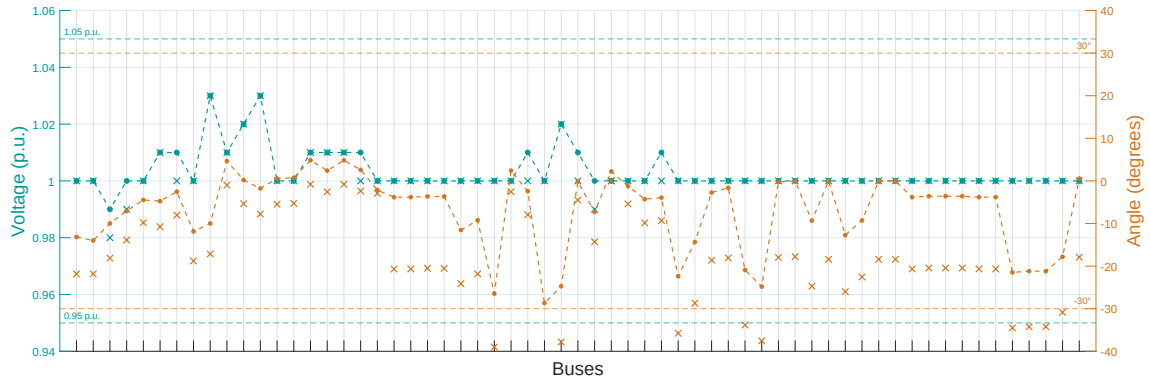


Figure H.4: N56 Hydro centric sub-scenario.

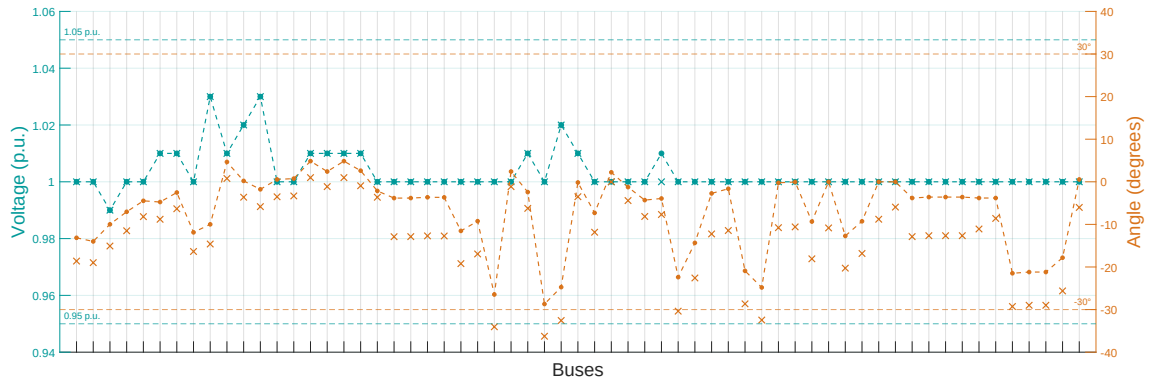


Figure H.5: N56 Hydro/BESS hybrid sub-scenario.

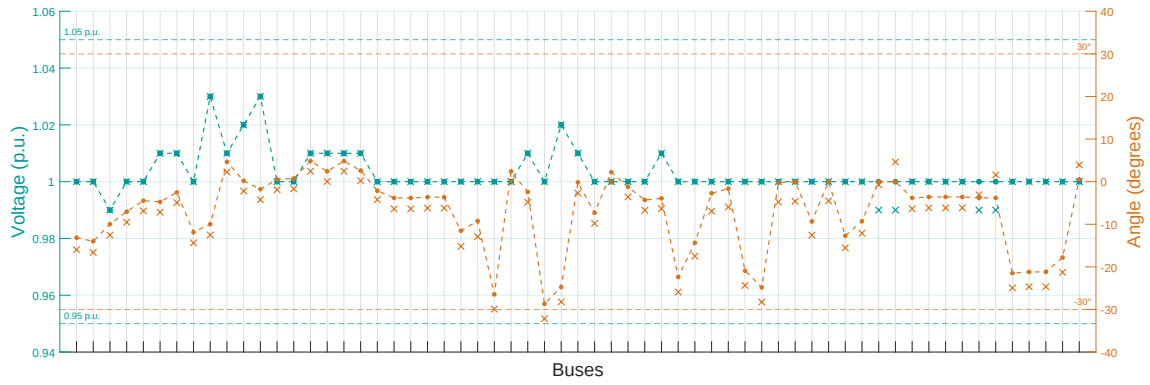


Figure H.6: N56 BESS centric sub-scenario.

DEPARTMENT OF ELECTRICAL ENGINEERING
CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden
www.chalmers.se



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