



HVDC-WISE



D6.1: Definition of the R&R-oriented methodology for the use cases

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Executive Summary

This document defines a common methodology aligned with the goals of the HVDC-WISE project to be applied to the use cases, thereby providing resilience and reliability-oriented HVDC-based reinforcement. It serves as the first version of Deliverable 6.1 within Work Package 6 (WP6). The associated task in this work package, Task 6.1, primarily focuses on:

- The practical methodology's overall framework is described, outlining the required inputs from other work packages (WPs) and expected outputs.
- An overview of the use cases, as per WP2, is provided, accompanied by a methodology that includes the grid topology and specifications, along with HVDC architectures for further study in the use cases.
- The R&R-oriented planning toolsets developed in WP5 are explained in the context of applying the methodology to the use cases. This involves assessing the grid using different indices, including techno-economic/adequacy indices, as well as reliability and resilience indices.
- The design of the methodology involves defining key indicators, practical assumptions, operational scenarios, and types of disturbances tailored to each use case's characteristics.

The final version of the deliverable, incorporating updates and improvements to the practical methodology for the use cases, will be submitted in June 2024.

1. Introduction

Task 6.1 primarily lays the groundwork for the R&R-oriented network expansion planning study of the use cases, related to other subsequent tasks in WP6, through the design of a practical methodology. This task facilitates the assessment and prioritization of different design options for HVDC architectures, which are developed to increase transmission network power transfer capability and enhance system reliability and resilience. The methodology involves defining key indicators, practical assumptions, operational scenarios, and types of disturbances tailored to each individual use case.

1.1 Scope and Objectives

This deliverable, D6.1, provides an overview of the project layout developed in D5.3 [1], outlining the interconnections and interactions between WP6 and other WPs. It subsequently delves into the data and findings required for designing the methodology in Task 6.1. This includes information related to the use cases from WP2, the identified suitable AC/DC grid architectures (encompassing various combinations of grid topologies and technologies) from WP3, and the toolset from WP5. The main objectives of the document, mainly focusing on the design of a practical methodology, are outlined as follows:

- To define key indicators, practical assumptions, operational scenarios, and types of disturbances tailored to each use case.
- To assess the use cases and prioritize different identified HVDC options using the defined indicators.

1.2 Future use of this document

This document is the first version of D6.1 and introduces a practical methodology developed to address HVDC design options, aiming to enhance system reliability and resilience. The methodology serves to assess and prioritize identified designs of an HVDC-based grid architecture for each of the realistic use cases in other subsequent tasks within WP6, e.g., Tasks 6.2 to 6.4. The updated version of this document, serving as the final deliverable for Task 6.1, is scheduled for submission in M21.

1.3 Structure of the document

The rest of the document is structured as follows:

- Section 2 offers a brief overview of the use cases, including the network basis, the focus of relevant studies, and the identified AC/DC grid architectures.
- Section 3 provides a detailed discussion of the introduced practical methodology for R&R-oriented HVDC-based reinforcement. In addition, it offers complementary explanations of the toolsets for applying the methodology to assess the grid with different identified AC/DC grid architectures and prioritize these design options through defined Key Performance Indicators (KPIs).

- Section 4 delves into the application of the methodology to the use cases, addressing intended studies and analyses, practical assumptions, operational scenarios, and types of disturbances tailored to each individual use case.
- Section 5 serves as the conclusion of the deliverable, summarizing key discussions and insights.

1.4 Update compared to the interim version of Deliverable D6.1

Since the first version of Deliverable 6.1, the deliverable has been thoroughly reviewed internally and further clarifications were made regarding the use cases, the methodology and the technologies to be used. These are now reflected in this version of the deliverable, including also an additional tool on power system restoration. The final version of D6.1 thus provides a comprehensive methodology for assessing the reliability and resilience of the use cases under the defined operational scenarios and AC/DC technologies.

2. Overview of Use Cases

This section provides an overview of all three realistic use cases required for studies in the subsequent tasks (T6.2, T6.3, and T6.4) within WP6. This overview encompasses the network basis, the focus of relevant studies, and the identified AC/DC grid architectures for all use cases.

2.1 Overview of the use cases

The following descriptions of the use cases, offering a brief overview, are adopted from the extensive discussions in WP2.

- **Use case 1:** The Continental European grid serves as the basis for this use case, primarily focusing on the reinforcement of a highly meshed network. The HVDC systems will primarily be embedded in a single synchronous zone, operating in parallel with the AC corridors of the onshore system. Although there will be a large amount of HVDC connections, this system will still be “AC-dominated”. This configuration enables the exploration of the advantages of HVDC overlay grids and facilitates the analysis of interactions between large AC/DC networks, as well as their risks in case of failures.
- **Use case 2:** This use case resembles the mainland GB grid, as an example of a small or medium synchronous area, with an emphasis on the HVDC systems needed to transfer power from wind-rich zones both onshore and offshore to distantly located demand centres. The use case will explore options for the connection of large offshore wind farms and reinforcement of transmission capacity via embedded point to point or multi-terminal HVDC networks. It represents a smaller onshore network with a rapidly declining reliance on synchronously connected generation, resulting in associated impacts on inertia, fault current, and voltage support. It allows for the investigation of challenges associated with a hybrid AC/DC network dominated by the combination of HVDC and converter-connected resources.
- **Use case 3:** This use case is defined based on a multi-purpose HVDC grid for both offshore wind integration and inter-area energy trade. The HVDC-based architectures of interest are those that could be used to interconnect the two other use cases. In this third use case, the requirements of each TSO area’s generation and HVDC performance standards must be simultaneously respected. Opportunities for new inter-area services (e.g., in inertia and frequency reserve sharing) must be identified and allocated across HVDC and generation while respecting minimum firewall requirements between the TSO areas.

Table 1 summarizes the above discussions on the use cases, including the network basis, the focus of relevant studies, and the identified AC/DC grid architectures.

TABLE 1: SUMMARY OF THE USE CASES INCLUDING THE CORRESPONDING NETWORK AND TARGET OF STUDY

	Use case 1	Use case 2	Use case 3
Network Basis	The continental European network	The GB network	Interconnection of EU and GB networks
Focus	Reinforcement of a highly meshed network	Reinforcement of a small or medium synchronous area	Multi-purpose HVDC grid for offshore wind integration and inter-area energy trade
AC/DC Grid Architectures	HVDC systems embedded in a single synchronous zone, operating in parallel with onshore AC corridors	Connecting wind-rich zones onshore and offshore to distantly located demand centres through point-to-point or multi-terminal HVDC networks	Offshore multi-terminal HVDC grid options connecting Use Case 1 and Use Case 2

2.2 AC/DC architectures

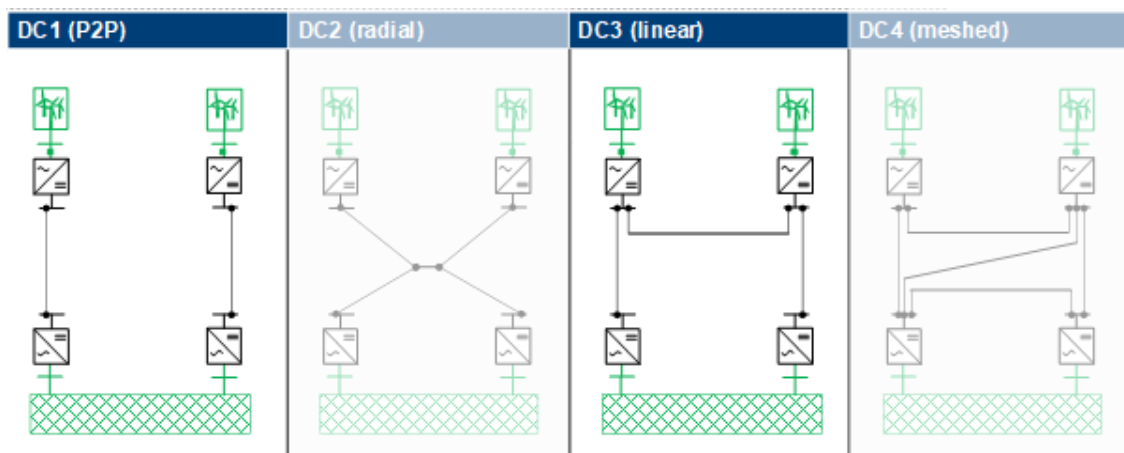
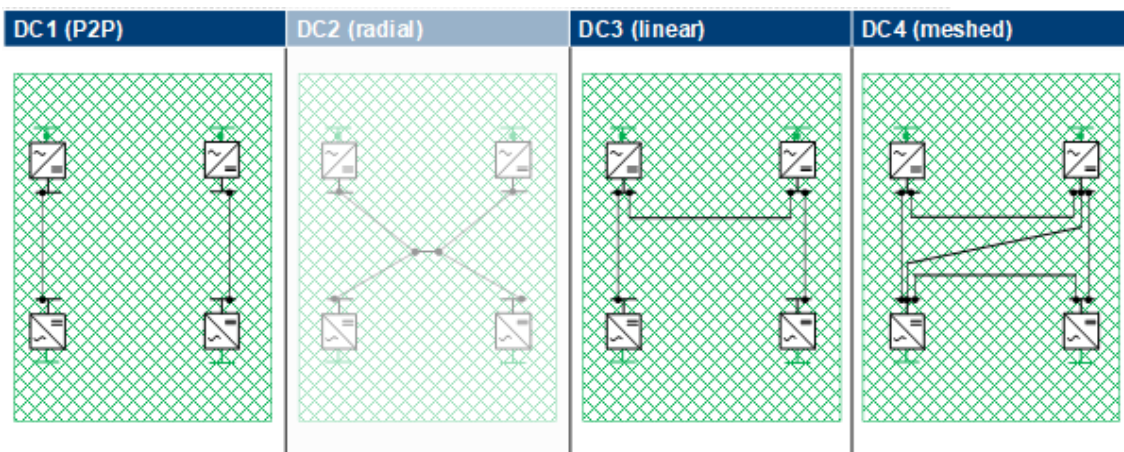
This subsection also provides a brief overview of the relevant AC/DC architectures for each use case. Further details can be found in D3.1 [2].

2.2.1 Use case 1

Table 2 offers an overview of the primary architectures relevant to use case 1, with less relevant ones shaded in grey. The main focus of evaluations in use case 1 lies on point-to-point and multi-terminal HVDC networks connected to a single AC grid. These networks are either fully embedded (AC3 – no-infeed) or connect multiple offshore wind farms to the same synchronous AC network (AC2a – multi-infeed). While AC2b systems linked to other AC grids (UK, Nordic) might be part of the grid scenario, they will not be actively varied during candidate architecture design. The development of candidate architectures will concentrate on AC3 and AC2a systems, with other systems remaining fixed in one or more scenario options. In addition, a graphical overview of the relevant cases is provided in Figure 1 and Figure 2.

TABLE 2: OVERVIEW OF AC/DC ARCHITECTURES PRIORITIZED FOR USE CASE 1.

AC (see D3.1)	DC (see D3.1)	Use Case 1 Relevance
AC1 (all separate)	DC1 (P2P)	low
	DC2 (radial)	
	DC3 (linear)	
	DC4 (meshed)	
AC2a (onshore embedded, offshore wind farms)	DC1 (P2P)	high
	DC2 (radial)	low
	DC3 (linear)	very high
	DC4 (meshed)	medium
AC2b (both sides embedded)	DC1 (P2P)	high (existing interconnectors)
	DC2 (radial)	low
	DC3 (linear)	
	DC4 (meshed)	
AC3 (fully embedded)	DC1 (P2P)	high
	DC2 (radial)	medium
	DC3 (linear)	very high
	DC4 (meshed)	high


FIGURE 1: RELEVANT DC TOPOLOGIES FOR AC2a (LESS RELEVANT ARE GRAYED OUT).

FIGURE 2: RELEVANT DC TOPOLOGIES FOR AC3 (LESS RELEVANT ARE GRAYED OUT).

2.2.2 Use case 2

The primary focus for use case 2 is on multi-terminal DC grids to connect large volumes of offshore generation to shore, while also incorporating existing architectures such as point-to-point interconnectors, embedded HVDC links, and direct offshore wind connections. Similarly, Table 3 outlines the most relevant architectures prioritized for use case 2. Figure 3 to Figure 8 also present a graphical overview of these architectures for use case 2.

TABLE 3: OVERVIEW OF AC/DC ARCHITECTURES PRIORITIZED FOR USE CASE 2.

AC (see D3.1)	DC (see D3.1)	Use Case 2 Relevance
AC1 (all separate)	DC1 (P2P)	low
	DC2 (radial)	
	DC3 (linear)	
	DC4 (meshed)	
AC2a (onshore embedded, offshore wind farms)	DC1 (P2P)	high
	DC2 (radial)	low
	DC3 (linear)	high
	DC4 (meshed)	low/medium
AC2b (both sides embedded, onshore to onshore or onshore to offshore AC island)	DC1 (P2P)	high (existing / future interconnectors)
	DC2 (radial)	low
	DC3 (linear)	medium (offshore plant AC-side connected)
	DC4 (meshed)	low
AC3 (fully embedded)	DC1 (P2P)	high (existing / future embedded)
	DC2 (radial)	low
	DC3 (linear)	medium
	DC4 (meshed)	low

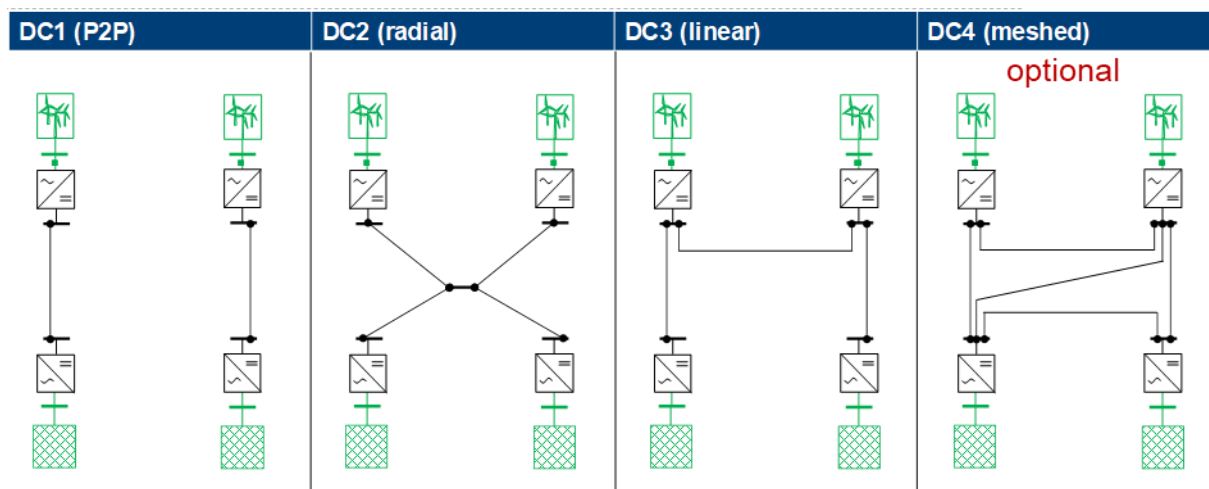


FIGURE 3: DC TOPOLOGY OPTIONS FOR USE CASE 2.

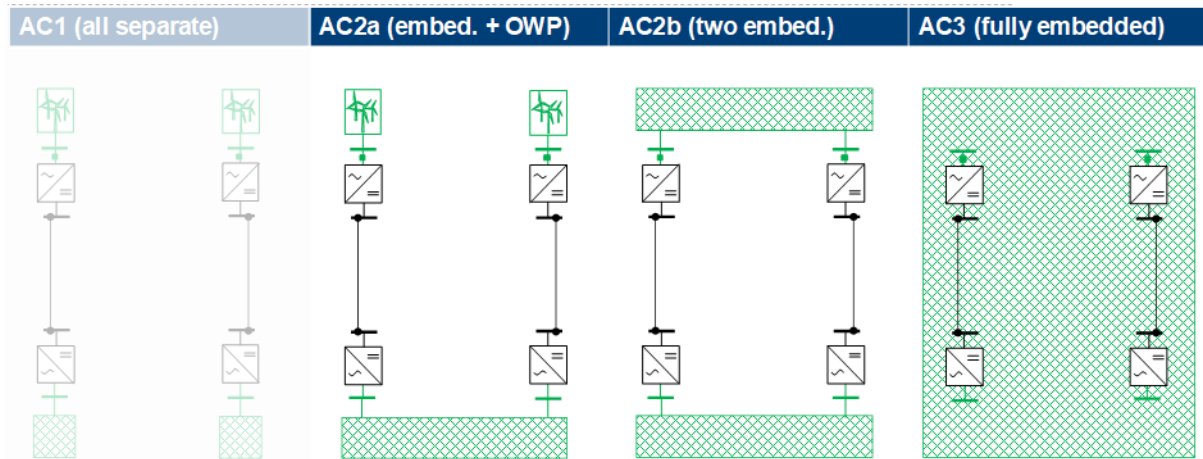


FIGURE 4: AC CONNECTION CONFIGURATION OPTIONS FOR USE CASE 2 – POINT-TO-POINT (DC1).

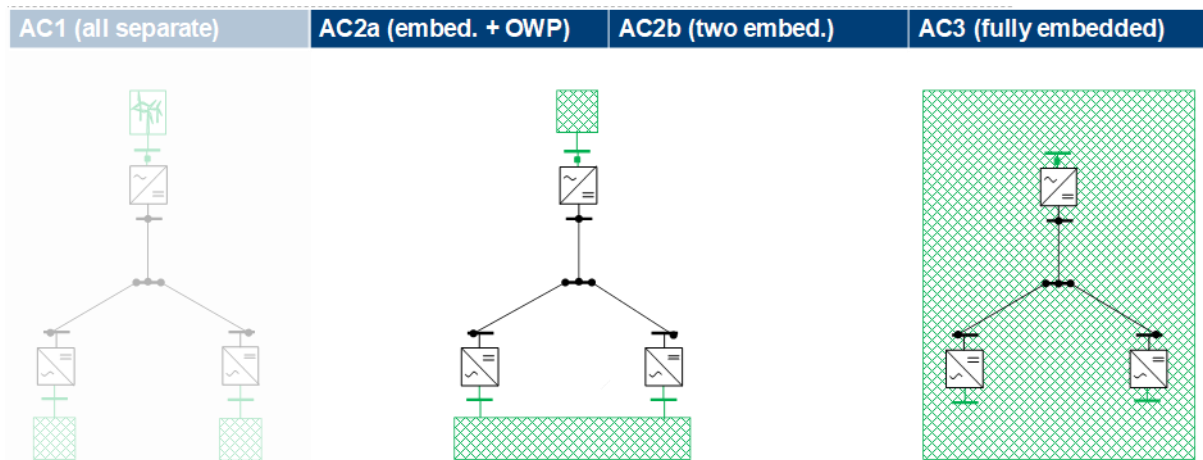


FIGURE 5: AC CONFIGURATIONS FOR USE CASE 2 – RADIAL MULTI-TERMINAL (DC2) TOPOLOGIES.

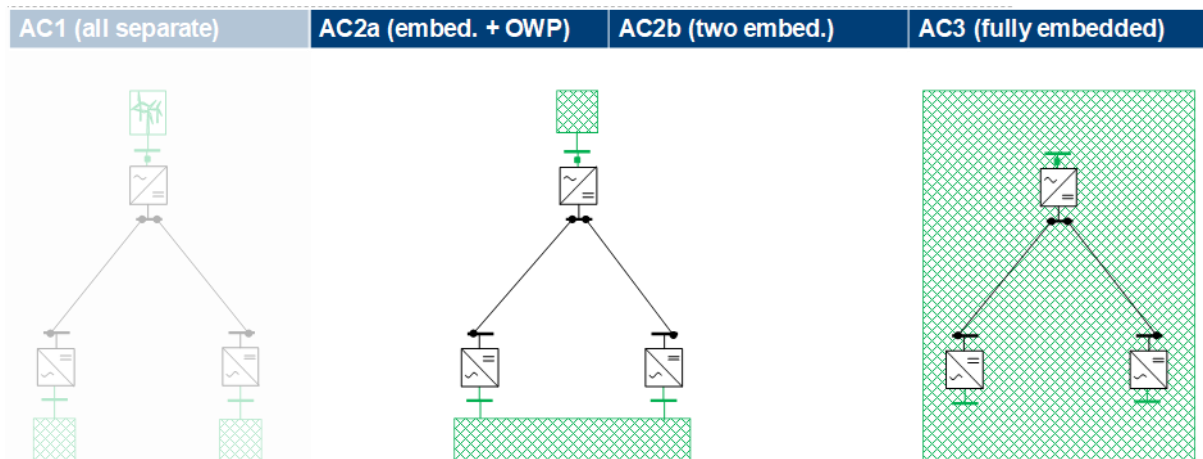


FIGURE 6: AC CONFIGURATIONS FOR USE CASE 2 – LINEAR THREE-TERMINAL (DC3) TOPOLOGIES.

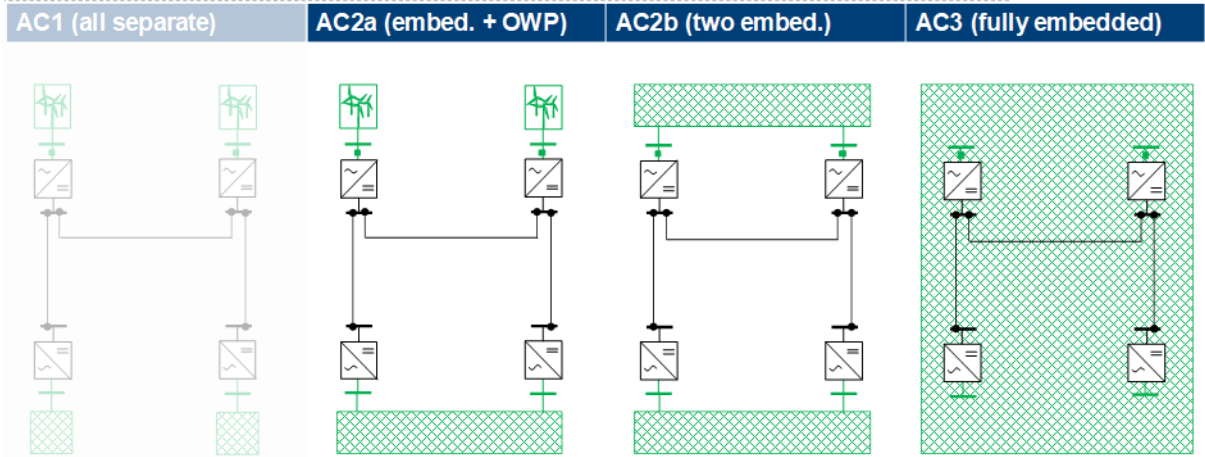


FIGURE 7: AC CONFIGURATIONS FOR USE CASE 2 – LINEAR FOUR-TERMINAL (DC3) TOPOLOGIES.

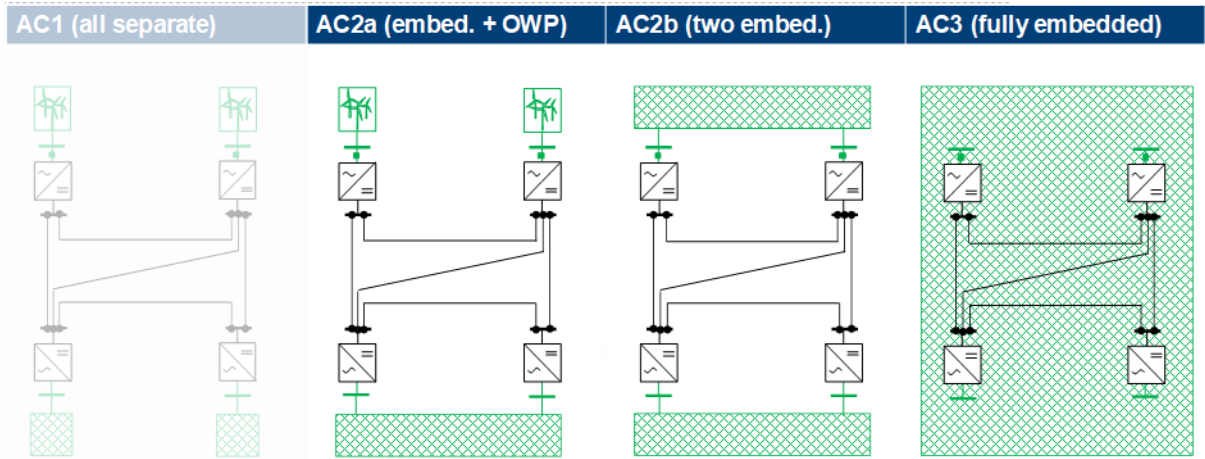


FIGURE 8: AC CONFIGURATIONS FOR USE CASE 2 – MESHED FOUR-TERMINAL (DC3) TOPOLOGIES (OPTIONAL).

2.2.3 Use case 3

In the context of Use Case 3, three different DC topologies are initially considered: a reference P2P topology, a low-meshed topology with an emphasis on radial connections, and a high-meshed topology. The reference case is not intended to be a realistic scenario that can or will occur in the future. It provides the basis for a comparison of the low and high meshed topologies to demonstrate the added value of the MT HVDC systems in terms of security, resilience and reliability. Table 4 provides an overview of the architectures that fall within the scope of Use Case 3.

Figure 9 gives an overview of the HVDC topologies addressed, divided into three levels, which are used to demonstrate the benefits and implications of different protection strategies in the HVDC system. The relevant AC requirements also need to be met, so the development of a hybrid AC/DC R&R planning toolset must take these factors into account. The first stage serves as a reference case and focuses on the P2P connections of a potential future scenario. The second stage is considered as a fictional evolution, focusing mainly on radial and linear connection of the P2P links [2]. The third stage is a fully meshed HVDC network, which serves as a desired scenario to demonstrate different C&P functions and technologies in the systems. It can be assumed that if the R&R planning toolset allows

the assessment of the C&P functions for the fully meshed system, the earlier stages with radial, linear and P2P connections are also possible.

According to Figure 9, Topology 1 serves as a reference case and is mainly characterized by P2P links and nationally connected wind farms. The only two international links are the Triton link between BE and DKW, and Nautilus between BE and the UK. Smaller multi-terminal structures are mainly found nationally, such as in NL or DKW. Topology 2 features a low meshing of the DC systems, with primarily national interconnections added compared to the reference topology. These include an offshore network in the UK, an additional connection of the PEI hub to BE, and the formation of a hub in the Danish and German North Sea. As an international connection, a link between a German and a Dutch wind farm is added. Topology 3 is characterized by a high level of interconnection, including the addition of the Lion link between the UK and BE. The hub in the German North Sea is also connected to the existing interconnection with NL. Additionally, an offshore connection is made between the hub in DKW and the hub in DE.

Figure 10 gives an overview of the relevant AC PoC of the different topologies discussed above. These represent the TSOs' view of the relevant connection points that may be realistic and lead to a high impact on the AC networks. They also reflect the challenges ahead (such as a large number of connection points with offshore infeed and electrolyser loads) in terms of system stability aspects of the future hybrid AC/DC network.

TABLE 4: OVERVIEW OF AC/DC ARCHITECTURES PRIORITISED FOR USE CASE 3.

AC (see D3.1)	DC (see D3.1)	Use Case 3 Relevance
AC1 (all separate)	DC1 (P2P)	Low
	DC2 (radial)	Low
	DC3 (linear)	Low
	DC4 (meshed)	Low
AC2a (onshore embedded, offshore wind farms)	DC1 (P2P)	High
	DC2 (radial)	High
	DC3 (linear)	Medium
	DC4 (meshed)	High
AC2b (both sides embedded, onshore to onshore or onshore to offshore AC island)	DC1 (P2P)	High
	DC2 (radial)	High
	DC3 (linear)	Medium
	DC4 (meshed)	High
AC3 (fully embedded)	DC1 (P2P)	Low
	DC2 (radial)	
	DC3 (linear)	
	DC4 (meshed)	

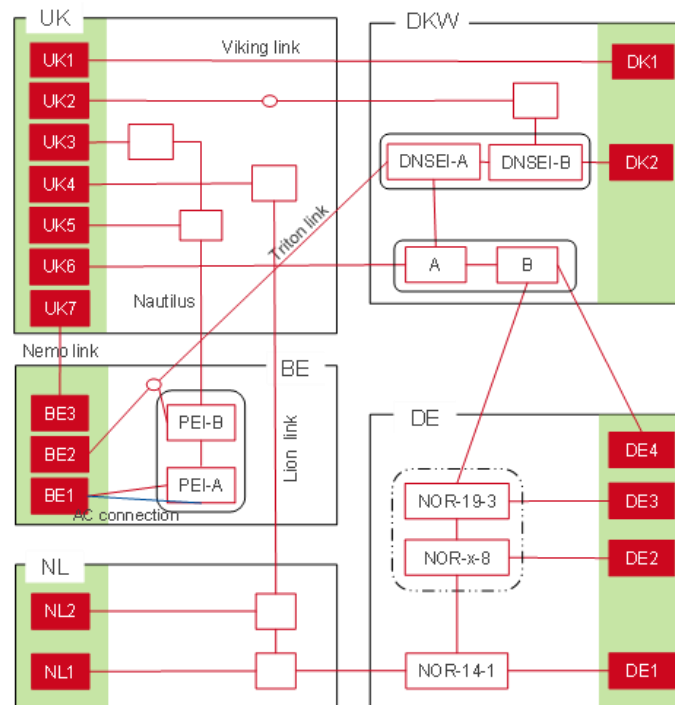


FIGURE 9: TOPOLOGY 1, 2 AND 3 FROM THE STUDY ON INTERNATIONAL OFFSHORE INTERCONNECTION CONSIDERED IN USE CASE 3.

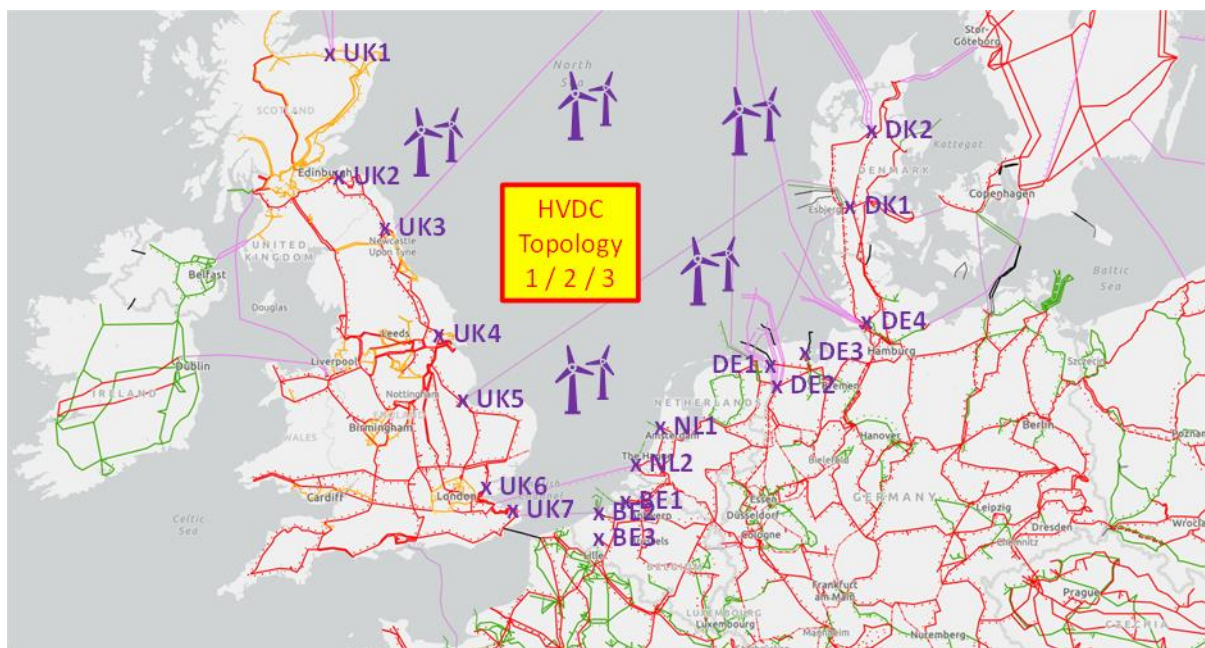


FIGURE 10: ILLUSTRATION OF THE AC POCs IN THE CONNECTED AC NETWORKS CONSIDERED IN USE CASE 3.

3. Designing a methodology for R&R-oriented HVDC-based reinforcement

The methodology introduced in this section primarily focuses on evaluating different reinforcing design options tailored for HVDC-based grid architectures in real use cases. It encompasses a variety of studies, including techno-economic analysis, static and dynamic security assessments, and resilience analysis. Accordingly, the section delves into the representation of the conceptual framework of the practical methodology, introducing each incorporated analysis along with the models and data necessary for the corresponding studies.

3.1 Overview of the methodology

As introduced in D5.1 and further clarified in the accompanying document to D5.3 [1], the approach adopted within the project to support HVDC grid planning is to characterise each HVDC architecture candidate in terms of adequacy, security, and resilience. This enables comparisons and ranking of different grid expansion candidates, whether point-to-point or multi-terminal HVDC grids, through global or detailed performance indices describing the three different system properties. To achieve this, complementarity and synergy between analyses are exploited. Figure 11 represents the overall implementation layout of the project involving the details of each block.

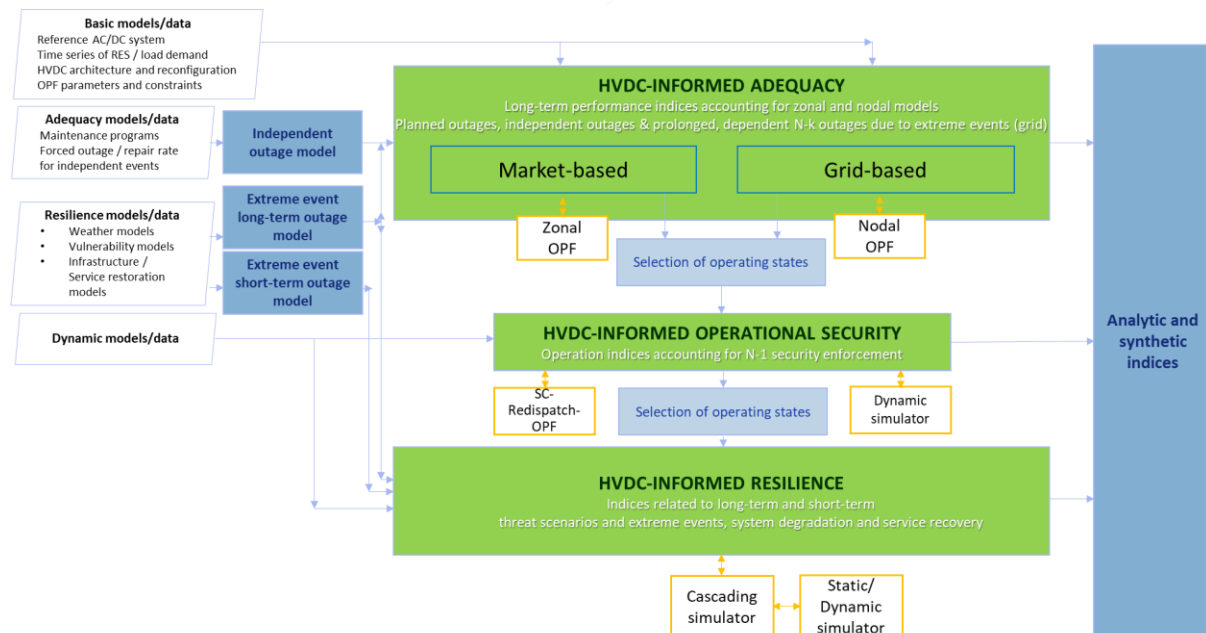


FIGURE 11: OVERALL IMPLEMENTATION LAYOUT IN DETAIL.

1) Adequacy assessment

Adequacy and other long-term performance indices assessed with Optimal Power Flow (OPF) tools are major components in the grid planning decision-making process. Several benefits

accounted for in the ENTSOE methodology for Cost-Benefit Analysis (CBA) of transmission projects rely on static analyses performed via OPF [1].

The Adequacy / Techno-Economic Analysis (TEA) block addresses evaluations of adequacy and other techno-economic indices that can be obtained by OPF functions, either zonal or nodal, accounting for HVDC features such as power flow controllability and operation under partially reduced capacity such as from bipolar to monopole operation. In particular, zonal OPF allows to replicate the energy market. Following this step, security KPIs can be computed, considering a detailed grid model (see next block “HVDC-informed security”). On the other hand, a range of adequacy and other techno-economic KPIs can be computed starting from a grid model, via nodal OPF.

The sets of inputs to the different OPF functions, in terms of time series of load demand, renewable generation potential and availability of system components can be defined according to the specific aims of the analyses. For instance, for adequacy evaluations it is important to account for the variability of load/renewable and availability as much as possible. Out of this set it may be worth selecting just a limited, representative subset of initial operating states to be passed to the subsequent security analysis, due to the computational burden of this stage (see “Selection of operating states” block in the figure). Conversely, if the analysis focuses on the evaluation of the actions and costs for systematic enforcement of security within the market-security chain, a suitably pre-selected time series may be adopted in input, with no need for further dimension reduction before moving to the Security block.

The input for adequacy analyses will thus generally consist of (many) time series of independent outages (see “Independent outage model” block in the figure), processed by nodal OPF within Monte Carlo simulation according to “conventional” adequacy approaches. A link with resilience can be added in adequacy analyses, suitably considering (un)availability of multiple components due to extreme events (“extreme event long-term outage model” box in the figure). In this way, long-duration effects of extreme events on system adequacy can be quantified (while the “immediate” evolution of extreme events is addressed in the Resilience block).

2) Security assessment

Security analyses provide insights into security constraints enforcement, relevant costs, and possible stability issues. The Security block applies Security-Constrained (SC) OPF to the output of either the zonal or the nodal OPF from the Adequacy block. In particular, the optimisation problem is formulated as a redispatch SC-OPF, as it is aimed to modify the operating condition in input. The SC-OPF is used to compute security-related KPIs and to identify N-1 secure operating conditions to feed the subsequent Resilience block. The Security block can also encompass dynamic analyses to check that the contingencies addressed in SC-OPF do not involve stability issues, and to devise constraints for the SC-OPF. Again, as resilience analyses are computationally expensive, a subset of representative operating conditions should be selected to be passed to the Resilience block (“Selection of operating states” block).

3) Resilience assessment

Resilience analyses allow to quantify impacts and costs of N-k events. The Resilience block computes resilience KPIs based on detailed analyses of extreme events. To this aim, static or dynamic cascading simulators can be exploited. Extreme events can be randomly sampled,

based on suitable models or historical data series of the weather threat and infrastructure vulnerability (see “Extreme event short-term outage model” box in the figure), and the detailed sequence of contingencies in the system is simulated. In addition, events derived from a long-term outage model can be simulated, in order to account for specific events relevant over the long-run of the power system (see “Extreme event long-term outage model” block in the figure).

It is worth remarking that the methodology depicted in the figure is general and comprehensive, and it can be customised according to the specific features and needs of the use cases. Each Use Case (UC) will implement a specific workflow where each function can be carried out by different tools.

Simplification of the overall implementation layout in Figure 11 results in the methodology's flowchart, as depicted in Figure 12. The flowchart shows the key steps of the comprehensive methodology involving the overall, high-level conceptual scheme for R&R evaluations at the planning stage. The process includes three major blocks, respectively devoted to adequacy, security and resilience. It commences with input data and models, AC/DC architectures and configurations, as well as adequacy, resilience, and dynamic models and data. The methodology's subsequent computational stages begin with market simulation and progress through techno-economic analysis, security assessment, and resilience analysis. The methodology then ends with the prioritization of different reinforcing design options for HVDC-based grid architectures.

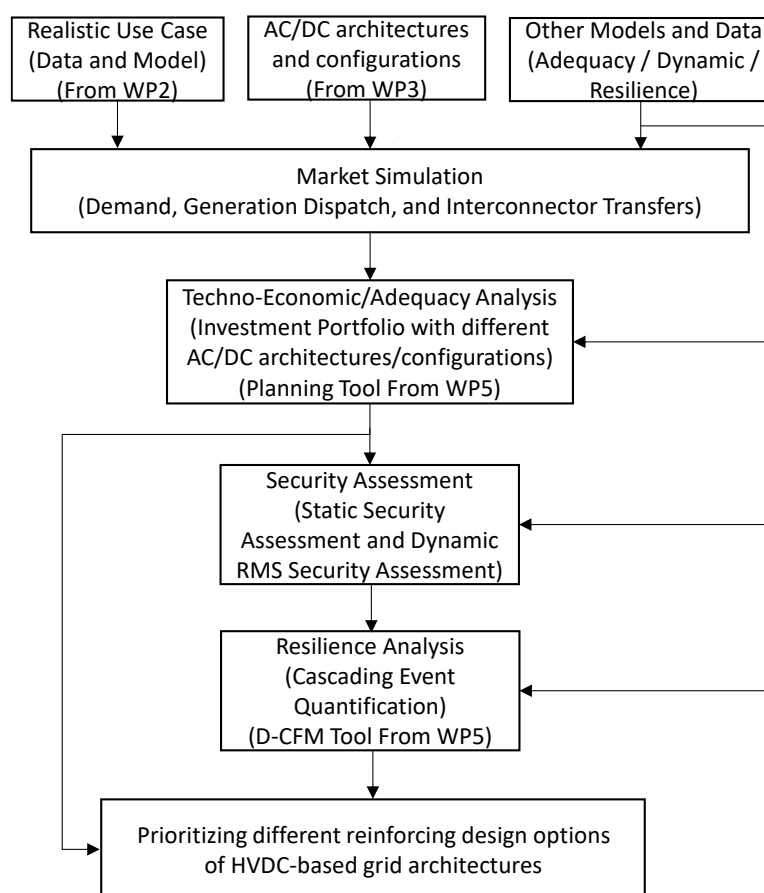


FIGURE 12: SIMPLIFIED FLOWCHART OF THE PRACTICAL METHODOLOGY.

3.2 Description of tools for the R&R oriented methodology

The primary goal of a comprehensive R&R-oriented planning toolset is to have interfaced tools incorporating respective metrics and methodology into an appropriate representation of future HVDC-based grid architecture concepts, fulfilling TSOs' resilience and reliability needs. As conceptually represented in Figure 13, the development of this innovative planning toolset is driven by the need for effectively assessing trade-offs among reliability, resilience, and cost for future HVDC systems integrated within existing power systems. The toolset, comprising a set of metrics, a comprehensive methodology, and specific tools, is developed to evaluate different HVDC-based grid architectures by comparing and prioritizing the respective reinforcing design options.

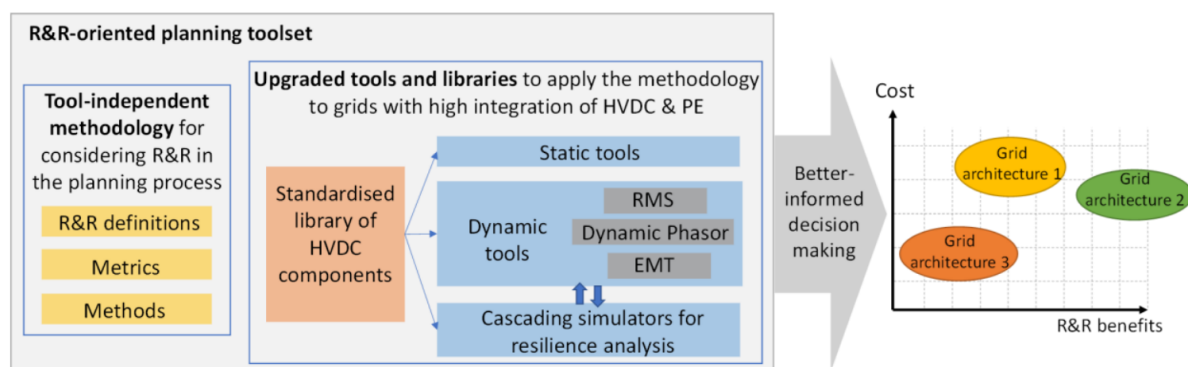


FIGURE 13: CONCEPTUAL REPRESENTATION OF THE R&R-ORIENTED PLANNING TOOLSET FUNCTIONALITIES (ACCORDING TO THE PROJECT PROPOSAL).

3.2.1 Tools for adequacy assessment

3.2.1.1 Grid-based adequacy and techno-economic analysis (TEA)

Adequacy¹ and other techno-economic indices of mixed AC/DC grids are obtained by expanding the methodologies and tools for AC system adequacy / techno-economic analysis (TEA) evaluations to account for DC features (e.g. controllability, possibility of operation under partial failure conditions) and resilience aspects, namely the impact of enduring outages due to extreme events on system adequacy. To this aim a specific methodology has been devised, that combines a conventional approach, accounting for probabilistic models of independent unavailabilities of components (generators, grid elements) via Monte Carlo simulation, with an innovative direct probabilistic approach accounting for long-lasting unavailabilities due to the after-effects of resilience events. In the following, the OPF framework is recalled, with focus on the independent unavailability management.

¹ Definitions of adequacy and other system properties are recalled in D5.1 and in [21]. See also CIGRE C1 definition of reliability [21].

Framework

The OPF tool, labelled as *HVDCWISE_TEA.jl*, is an open-source package developed in Julia language. It mainly consists in a wrapper of other open-source, research-graded Julia packages for power system analysis, as described in the accompanying document of D5.3 [1].

The primary objective of this tool is to assess the viability of a proposed High Voltage Direct Current (HVDC) expansion architecture, whether it is point-to-point or multi-terminal, in terms of adequacy indices and techno-economic metrics commonly utilised in cost-benefit analyses. This is done in a robust and probabilistic way by evaluating the HVDC candidate under multiple “micro-scenarios” to account for uncertainty related to load consumption, renewable generation and power system component failure.

Input data

The techno-economic analysis is based on a macro-scenario for a target year (e.g. 2030 or 2050) providing transmission power system data that are fixed over the simulated time horizon. This includes, among others, the grid model with HVAC and HVDC line ratings, installed generation, operational costs of generators, demand characteristics (such as maximum load absorption), load flexibility characteristics at nodal level. Alongside the macro-scenario data, (typically hourly) time series must be provided to vary specific parameters of the model, namely:

- Nodal active power demand
- Wind, photovoltaic and Run-of-River available generation (taking into account a weather scenario)
- Inflows of dispatchable hydro power plants
- Unavailabilities of generating units and grid components, both HVAC and HVDC

These time series define a single micro-scenario. In addition to the input data recalled above, some further data requirements are provided hereafter:

- AC/DC grid
 - Multiconductor description of HVDC grids
 - AC/DC line type: cable vs. overhead (for fault/repair rates within independent and extreme events)
- Parameters for evaluation of KPIs (post-processing of OPF results), such as Value of Lost Load (VOLL), CO2 cost, cost of curtailed Renewable Energy Source (RES) generation

Modelling choices

An HVDC expansion candidate is evaluated for multiple micro-scenarios to account for uncertainty using a Monte Carlo approach. For each given micro-scenario, a multi-period OPF problem with hourly resolution is solved. The objective of the OPF problem is to minimize the sum of system operational costs over the defined time horizon, which typically consists in a year, while abiding by the physical and operational constraints of the power system. Specifically, the model accounts for operational costs related to generator fuel, voluntary demand reduction, voluntary demand shifting and mandatory load curtailment.

A multi-conductor modelling approach based on [3] is applied for DC components (i.e., buses, HVDC lines, and AC/DC converters). This is motivated by the fact that, in case of unbalanced operation (e.g., fault at one pole of a bipolar HVDC line or AC/DC converter), a single conductor model fails to correctly

represent power flow within the HVDC grid, resulting in an incorrect solution and in a potential overestimation of generation cost.

Several simplifications are introduced in the model in order to limit the overall computational cost of the optimisation and analyse multiple micro-scenarios in a reasonable time:

- A linearised formulation of the OPF problem is used. Therefore, voltage magnitude and reactive power variables and constraints are not modelled.
- Integer variables typically used in the unit commitment problem are disregarded to avoid solving a mixed-integer formulation. The lower bound for active power is set to zero for all generators except for must-run ones, and start-up and shut-down times are not considered.
- Only inter-temporal constraints that are necessary to properly model flexibility resources (i.e., demand shifting and energy storage devices) are accounted for. Among others, generator ramping constraints are not included.
- Due to the used linearised formulation, it is not possible to distinguish between LCC and VSC converters from a quasi-steady-state modelling standpoint, as reactive power is disregarded.

The outputs of the OPF problem for a micro-scenario consist in the optimal generator setpoints and, possibly, in the RES curtailment and load voluntary or mandatory reduction for each hour of the year. From these outputs, several KPIs can be computed. The computed setpoints are feasible with respect to the specific situation of components' availability (that may include N-1 or N-k unavailabilities), provided as input data. Accordingly, and consistently with conventional adequacy assessment approaches, the outcome of the OPF may not be (further) N-1 secure.

3.2.1.2 Long-term failure model

Extreme weather events may cause severe infrastructure damage, leading to blackouts. The disruption process and the subsequent service restoration are addressed by resilience analyses. However, especially in case of widespread and severe events, infrastructure restoration (e.g., repair or replacement) may take long, such as days, weeks or even months. The power grid thus results in a structurally weak condition, potentially prone to adequacy issues. It is therefore important that the assessment of adequacy indicators in the project accounts for the long-lasting (e.g. for weeks or months) unavailabilities of grid assets due to extreme events. To this purpose, within the adequacy assessment methodology (see subsection 3.2.1.1) it is important to account not only for independent, but also for dependent, long-lasting multiple outages related to the occurrence of extreme events.

A “long-term failure model” previously developed for resilience analyses in the planning stage [4] has been adapted for the project. Its objective is to identify multiple failures and their probability, that may result from extreme weather events, considering weather conditions over the long term. Thus the “contingency” is actually turned into an “unavailability”. In this regard, the contingency model is complemented by a recovery model, that determines the sequence and timing of the infrastructure restoration.

The methodology is divided into these steps:

1. Analysis of past weather events,
2. Vulnerability model definition,
3. Calculation of the return periods of grid asset failures

4. Calculation of the correlation among weather events affecting the grid asset,
5. Detection and evaluation of the probability of occurrence of the more probable N-k contingencies,
6. Modelling of the recovery process.

It is worth remarking that the evaluation of the adequacy impact of extreme events is complementary to the assessment performed by the Resilience module. The latter addresses in detail the power system evolution as a specific threat (either sampled or predefined, e.g. reproduced from historical events) is unfolding, hence considering the threat evolution (in the order of hours), the individual failures occurring in sequence, the progressive system degradation (possibly with cascading failures), and the (infrastructure and) service recovery in the immediate aftermath of the event (in fact, some infrastructures may be repaired shortly after the event). The TEA module addresses the subsequent stages (weeks, months) i.e. the system power supply performances with the grid still weakened by the event. The long-term contingency model can also feed the Resilience module with a list of contingencies that are relevant on long-term analysis horizons, in order to simulate the system response to the event while this is unfolding. Each contingency from the long-term contingency model is characterised by the set of components that fail, not by the sequence of the failures, hence in the simulation all affected components are considered to fail together. In this regard, the cascading analysis may result conservative.

The sequel of the description will focus on the “wind” threat, but the methodology is general and can be applied to any threat characterised by one or more stress variables affecting the grid assets. To simplify the description of the workflow, in the specific case of wind threat, only the wind speed is considered as stress variable. Figure 14 summarises the workflow of the methodology [4] with focus on the wind threat.

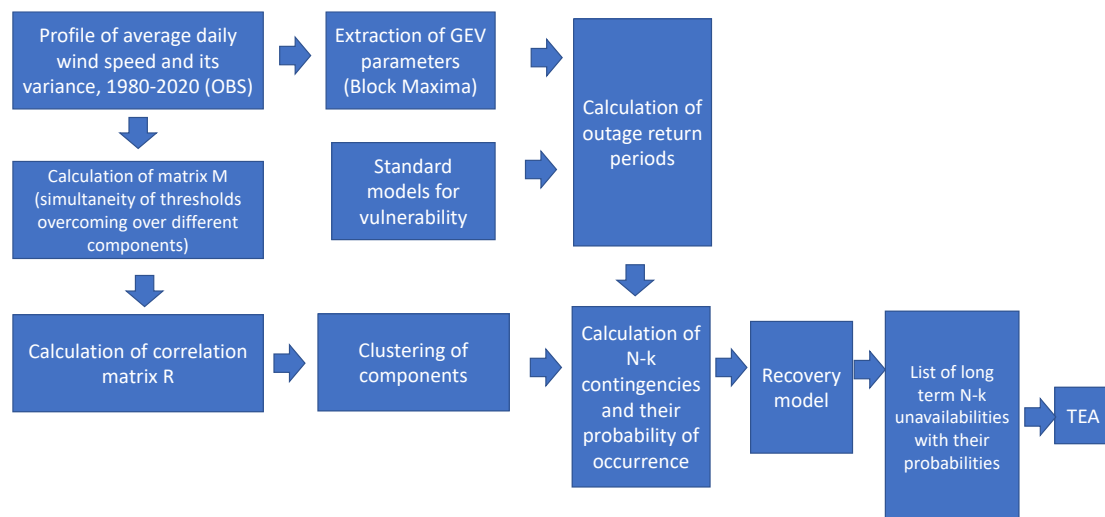


FIGURE 14: SPECIFICATION OF THE WORKFLOW FOR THE LONG-TERM N-K FAILURE MODELING FOR THE “WIND” THREAT.

3.2.1.3 Integration of long-term multiple failure model with the grid-based adequacy assessment

The integration of the Monte Carlo-based probabilistic approach for adequacy assessment in case of independent events (subsection 3.2.1.1) with the direct probabilistic approach used in the identification of the extreme, dependent events and their probability (subsection 3.2.1.2) required a

specific methodological development that led to a hybrid approach to attain the scope of availability time series generation:

1. A Monte Carlo Sampling technique is applied to generate a sufficiently representative set of time series of availabilities of the components associated with independent failures of AC and DC grid components (e.g. generators, branches, converters). The main inputs are the MTTF (Mean Time to Failure) and MTTR (Mean Time to Repair) from statistics of past fault events. The framework for this analysis was presented in subsection 3.2.1.1 above.
2. An analytical method identifies the most probable dependent N-k failures and computes their yearly probabilities of occurrence. The main inputs are the historical series of the stress variables more related to the threat (e.g. wind gust speed in case of wind threat) over the grid under study, represented with a georeferenced model. The methodology calculates the GEV (Generalized Extreme Value) distributions for the stress variables over the grid components, as well as the correlations among relevant threat events affecting the components. The correlation matrix allows to identify clusters of components which tend to fail together, thus limiting the cardinality of the set of potential N-k failures of interest. After that, copula theory is exploited to compute the probability associated with each multiple failure within each cluster [4].

Thus, the outcomes of the overall methodology for adequacy evaluations are:

1. a set of N_s time series of availabilities sampled using Monte Carlo simulation technique for the independent failures on AC and DC grid components; the probability of each unavailability situation is computed as its rate of occurrence with respect to the whole set of Monte Carlo samples (see subsection 3.2.1.1 above).
2. a set of N_{ctg} time series (one for each N-k failures retained by the analytical method) of unavailabilities in case of extreme events. A probability of occurrence is associated with each multiple failure.

The time series of unavailabilities from independent (including maintenance) and (N-k) dependent failure events are dealt with separately, under the simplifying assumption that extreme events occur in case of fully available grid conditions. This choice, though counter-conservative, is motivated by the fact that adequately sampling the combination of independent and dependent unavailabilities would be practically unfeasible. Moreover, dependent unavailabilities due to extreme events are rare events and independent unavailabilities are relatively little frequent, thus the probability of combined unavailabilities is quite low. Figure 15 reports the conceptual scheme of the hybrid approach.

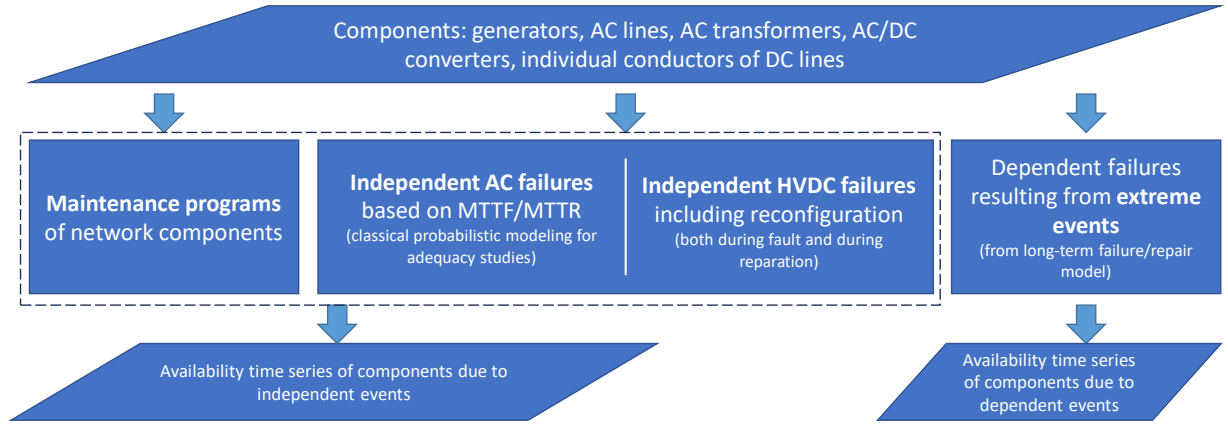


FIGURE 15: SCHEME OF THE METHODOLOGY FOR THE MANAGEMENT OF COMPONENT AVAILABILITIES.

Integration of the unavailabilities due to N-k contingencies in the TEA analysis

Each N-k contingency is characterised in terms of:

- Set of outaged components
- Probability of occurrence
- Time To Repair (TTR) of each outaged component

In view of the evaluation of the effect of long-lasting N-k unavailabilities on system adequacy, the time of application of the multiple contingency (hence, the specific operating point of the system when contingencies are applied) has a relatively minor role to quantify such effect, because a significant set of operating points of the grid (e.g. spanning over weeks) will be affected by these unavailabilities.

Thus, the basic idea is applying the N-k contingencies at a conventional hour of the year (e.g. 1st of January) and evaluate the effects of the relevant component unavailabilities over the subsequent hours of the year, up to the maximum of the TTRs of the components involved in the contingency definition. The UP/DOWN statuses of grid components for each N-k contingency are generated accordingly.

The basic idea is to separately quantify the effects of independent contingencies and dependent N-k contingencies in the adequacy analysis. In particular:

- The contributions of N-k contingencies is calculated using an analytical enumeration method (see subsection 3.2.1.2), applying each contingency at a conventional hour of the year, evaluating the effects in terms of Energy Not Served (ENS) for each of the hours exhibiting unavailabilities of the involved components, and finally evaluating the adequacy indices (Loss of Load Expectation, LOLE; Expected Energy Not Served, EENS) by analytically combining the impacts (in terms of ENS, and hours with unserved energy to customers) with the probability of the N-k contingencies (calculated in the previous steps).

To this regard, during the TEA analysis of the sequence of statuses associated to each N-k contingency, the tool computes:

- lost load $LOL_j^{(h)}$ due to j-th contingency for each hour h
- $F_j^{(h)}$ equal to 1 is in hour h a ENS > 0 takes place due to contingency j, 0 otherwise.

Indicators for each contingency are computed considering the annual failure rate $\lambda_j = 1/RP_j$

$$\begin{aligned}
 EENS_j &= \lambda_j \times \text{sum}(h, LOL_j^{(h)}) & [\text{MWh/yr}] \\
 ELC_j &= \lambda_j \times \text{mean}(h, LOL_j^{(h)}) & [\text{MW/yr}] \\
 LOLE_j &= \lambda_j \times \text{sum}(h, F_j^{(h)}) & [\text{hrs/yr}]
 \end{aligned} \tag{1}$$

- The contributions of N-1 contingencies are evaluated using the state duration sampling method, accounting for MTTF and MTTR of each grid components, coming from databases.
- HVDC contingencies are a specific class of contingency which affects the components of HVDC architectures. Typically, they are N-1 contingencies, and their repair times are usually very long. Specific experiences are needed to characterise the operation and the recovery of such architectures. The way how to integrate such contingencies in the TEA is similar to the one for N-k contingencies.

Such a hybrid approach (including both analytical enumeration approach and Monte Carlo simulation) neglects the potential “superposition” effects due e.g. to the presence of faulted components also during the long lasting unavailabilities of components struck by N-k contingencies.

3.2.2 Security-Constrained OPF

Two Security-Constrained OPF (SC-OPF) applications have been developed within the project by different partners, one included in the market-grid toolchain to address KPIs such as security costs, and the other one linked to the TEA OPF module with the aim to obtain N-1 secure operating states to feed the Resilience module. In fact, it is assumed that resilience analyses need to start from secure operating conditions, as would be assured by the TSOs in the operational planning stage, whereas the OPF only provides N-secure states due to its different scope. Thus, in case operating conditions obtained by the grid OPF are selected for resilience analysis, they need to be preliminarily made secure. The two SC-OPF applications are conceptually equivalent and demonstrate the implementation flexibility of the overall architecture.

The SC-OPF linked to the TEA OPF is formulated as a two-stage N-1 Security-Constrained Redispatching (SC-R) approach (Figure 16):

1. first stage to solve active power/angle related issues,
2. second stage to solve reactive power/voltage related issues.

In the context of the workflow, because the input to the SC-OPF is an output from an OPF, it is assumed that the input operating condition is N-secure, however this is not a necessary condition as N-security can be a by-product of the function.

The SC-R exploits both preventive and corrective control actions. The preventive actions include the redispatching of active power setpoints and AC voltage setpoints for AC conventional generators, the curtailment of renewable generators, the variation of shift angle of PSTs (Phase Shifting Transformers) as well as the power and DC voltage setpoints for DC grid converters with constant power and PV droop controls. The corrective actions include the load shedding, the corrective variations of active power and AC voltage setpoints for dispatchable AC generators, the corrective variations of DC voltage and power setpoints for DC converters of embedded HVDC grids.

The benefit of the proposed SC-R approach is that both stages are formulated as Linear Programming problems, where AC load flow equations are linearised: this makes the algorithm efficient to solve large power systems. Also, active/reactive decoupling techniques are used, so that two separate

problems can be solved in a cascaded way. The first stage is modelled using a conventional formulation based on Power Transfer Distribution Factors (PTDF) and provides the preventive variations of active power setpoints for AC generators and for AC/DC converters. The second stage is modelled based on a suitable decoupled formulation of reactive power/voltage problem [5] and provides the variations of AC voltage setpoints for the conventional AC generators and for converters, as well as the DC voltage setpoints for the converters.

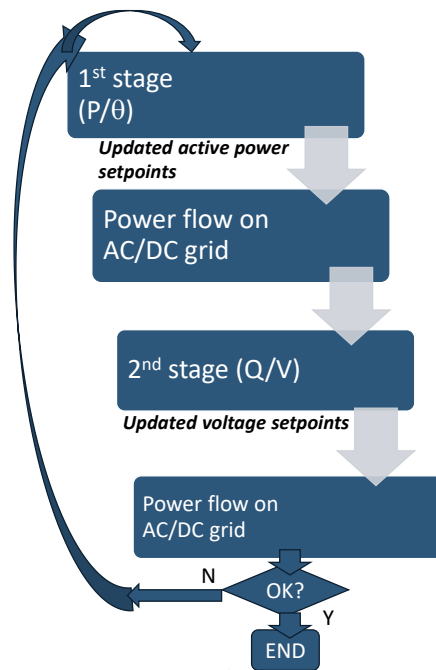


FIGURE 16: WORKFLOW OF THE TWO-STAGE SC-R.

The SC-R models both preventive and corrective control actions: this means that the operating condition in output from this module can be either “preventively” or “correctively” N-1 secure.

The benefits of the proposed SC-R approach are two-fold:

- the formulation of the two stages as Linear Programming problems makes the algorithm efficient to solve large power systems.
- The adoption of reactive/active power decoupling techniques permits to solve the two stages separately in a cascaded way.

The sets of contingencies which can currently be analysed are:

- N-1 contingencies of AC branches,
- N-1 contingencies of DC branches,
- N-1 contingencies of embedded converters. In particular, two failure modes are considered: either the loss of DC grid converter is simulated without losing the DC grid connectivity (no DC branches are tripped) or a DC bus fault is simulated with the simultaneous loss of both DC grid converters and DC branches connected to the faulty DC bus,
- N-1 contingencies of AC generators (including equivalent renewable injections).

The embedded VSC’s of DC grids are represented as fictitious generators on the AC grid, with a P-Q capability curve corresponding to the one of the VSCs. The VSC model is a lossless model and only the

control functions (such as V constant or VP droop) are accounted for in power flow and sensitivity calculations.

The first stage focused on active power/angle related aspects is formulated using the PTDF (Power Transfer Distribution Factors) on the AC grid, and a sensitivity-based approach also on DC grids. Specifically, in DC grid both the power flow and the calculation of the sensitivities between power and voltage setpoints and the DC currents and DC voltages are performed taking into account the different control strategies of the VSCs (constant V, constant P or VP droop).

The outputs are represented by:

- A. the preventive actions (to be performed on the initial operating condition independently of the occurrence of the contingencies): these actions consist in the preventive variations of active power setpoints for AC generators and for embedded DC converters with constant P and VP droop control, as well as the preventive curtailment of renewable injections and the variation of shift angle of PSTs (Phase Shifting Transformers).
- B. The corrective actions, which are deployed only in case of occurrence of contingencies and considering the ramp limitations of the devices subject to the control. They consist in the post-contingency variations of active power setpoints for AC dispatchable generators and for DC embedded converters with constant P and VP droop controls.

The Objective Function of the 1st stage consists in the sum of the total costs for preventive control actions and the total expected costs for corrective control actions and the expected costs for “lack of N-1 security”, as shown in (2).

$$OF = CP + \sum_{ctg} (CC_{ctg} + CS_{ctg}) p_{ctg} \quad (2)$$

where CP are the total cost for preventive actions, CC_{ctg} and CS_{ctg} are respectively the costs for corrective actions and for “lack of security” in case of occurrence of contingency ctg with probability p_{ctg} . The lack of security is quantified by introducing suitable feasibility variables to quantify the violations of grid security constraints (e.g. on the branch active power flows for stage 1) and associating large costs to the potential violations.

The controlled variables for stage 1 are:

- The active power flows on AC branches
- The current flows on DC branches

The constraints for the N state in the stage 1 of the algorithm include:

- equality constraints:
 - Balance of power in AC grids (N state preventively modified)
 - Balance of power on DC grids (N state preventively modified) for any DC grid
 - Active power flow on AC branches in N state
 - Current on DC branches
 - Matching constraints VSC-fictitious generators (i.e. setting the equality between the AC voltage on the AC side of embedded VSC and the AC voltage on the corresponding fictitious generator)
- inequality constraints:
 - Limits on current flows of DC branches
 - Technical limits for VSCs
 - Limits on active power flows of AC branches,
 - Generator upward and downward redispatch margins

- RES curtailment limit

The constraints for the N-1 state in the stage 1 of the algorithm include:

- equality constraints:
 - Balance of power in AC grids (N-1 state, ctg $k = 1 \dots N_{ctg}$)
 - Final injection of VSC after k-th ctg
 - Active power flow on AC branches in N-1 state
 - Final generation at gen j-th after k-th ctg
 - Matching constraints VSC-fictitious generator
 - Current on DC branches in N-1 state
 - Balance of power on DC grids (N-1 state)
- inequality constraints:
 - Limits on current flows of DC branches
 - Technical limits for VSCs
 - Limits on active power flows of AC branches
 - Generator upward and downward redispatch margins and ramping limits

The second stage is modelled based on a suitable decoupled formulation of reactive power/voltage problem as reported in [5]. The input is the operating condition preventively modified according to the preventive control actions suggested by stage 1 of the algorithm. The outputs consist in:

- Preventive control actions i.e. the preventive variations of the AC voltage setpoints for conventional AC generators and for DC grid converters, as well as of the DC voltage setpoints of the converters
- The corrective actions consist in the corrective variations of the AC voltage setpoints for conventional AC generators and for converters, as well as of the DC voltage setpoints for converters

The controlled variables for stage 2 are:

- The voltage magnitudes at AC buses
- The voltage values at DC buses
- The reactive power exchange of conventional AC generators and of embedded VSC converters
- The reactive power flows along the AC branches: the enforcement of this constraint jointly to the constraint on active power flows in stage 1 assures that the maximum apparent power allowable on the AC branches is not violated

The Objective Function (OF) consists in the sum of the preventive variations of the AC voltage setpoints at PV buses and the sum of the variations of DC voltage setpoints at DC buses connected to constant V or VP droop-controlled nodes, as well as the expected costs for the analogous corrective variations and the expected costs for infeasibilities.

Like in stage 1, the formulation with feasibility variables assures the convergence of the algorithm and the possibility to identify the reasons (e.g. specific buses) where the available resources do not assure the fulfilment of N-1 security criterion.

The constraints in N state for the stage 2 include:

- Equality constraints:
 - Initialization of reactive power exchange at PQ nodes
 - Voltages at PQ buses in N state (preventively modified)
 - Voltage at generator buses in N state (preventively modified)

- Total reactive power exchanged at PV nodes in N state (preventively modified)
- Reactive powers exchanged by generators in N state (preventively modified)
- Reactive power flows on the AC branches in N state
- Reactive power flow limits (accounting for the active power flow established after stage 1)
- No voltage setpoint variation at PQ nodes
- Voltages at DC buses using sensitivity in N state
- Currents on DC branches
- Inequality constraints:
 - Reactive power capability limits of generators
 - Technical limits for DC buses
 - AC/DC voltage constraint
 - Limits on current flows of DC branches
 - Technical limits for bus voltages in N state

The constraints in N-1 state for the stage 2 include:

- Equality constraints:
 - Initialization of reactive power exchange at PQ nodes
 - Voltages at PQ buses in N state (preventively modified)
 - Voltage at generator buses in N state (preventively modified)
 - Total reactive power exchanged at PV nodes in N state (preventively modified)
 - Reactive powers exchanged by generators in N state (preventively modified)
 - Reactive power flows on the AC branches in N-1 state
 - No voltage setpoint variation at PQ nodes in N-1 state
 - Voltages at DC buses using sensitivity in N-1 state
 - Currents on DC branches
- Inequality constraints:
 - Reactive power capability limits of generators
 - Technical limits for bus voltages in N state
 - Reactive power flow limits in N-1 state (accounting for the active power flow established after stage 1)
 - Technical limits for DC buses
 - AC/DC voltage constraint
 - Limits on current flows of DC branches

The final step consists in applying the preventive measures proposed in stage 2 to the operating condition already modified through stage 1 and checking the response of the modified operating condition to the set of N-1 contingencies under study, including the corrective actions suggested by the two-stage control.

3.2.3 Tool for cascading event quantification and operational mitigation strategies

As detailed in the respective deliverable D5.4 [6], the tool is designed to quantify cascading impacts through cascading failure modelling and analysis, capturing dynamic cascade mechanisms. The tool is developed on an integrated modular basis, as depicted in Figure 17, and benefits from a flexible framework that leverages either quasi-steady-state or dynamic cascading failure modelling, as well as

a weather event simulator. Several submodules, including the weather event simulation, cascading failure modelling, and operational mitigation strategy submodules, are integrated to perform initial cascading failure analysis and quantify impacts resulting from any type of weather-related or non-weather-related initiating events.

The weather event simulator derives the time- and weather-dependent status of the network impacted by weather events, like a windstorm, by utilizing a fragility-driven impact assessment approach for transmission lines and incorporating characteristics of the windstorm from historical data. If the user does not specify the initiating event(s), the tool calls this submodule to generate random scenario(s) of line outages. Subsequently, the tool provides an operational mitigation strategy that is tailored to the extent and severity of cascading propagation, thereby enhancing system resilience.

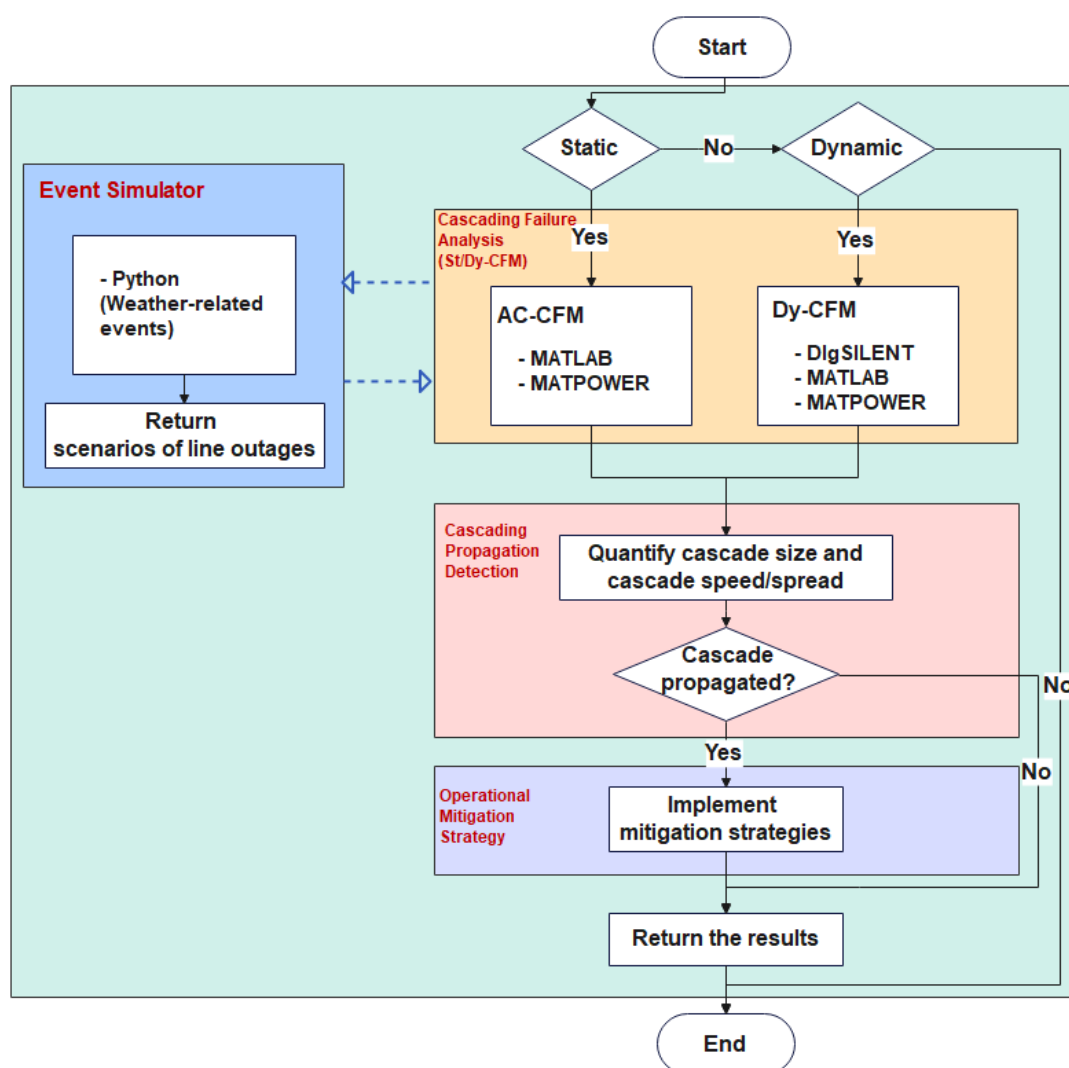


FIGURE 17: THE FLOWCHART REPRESENTING THE OVERALL FRAMEWORK OF THE CASCADING FAILURE MODELLING TOOL.

Figure 18 provides a visual representation of the tool's running process through a workflow diagram, showcasing the sequence of steps and interactions among different modules involved in the tool. After the tool's execution, it prompts the user to input a value of 1 or 2, corresponding to the preferred

study type: quasi-steady-state (QSS) using AC-Cascading Failure Modelling (AC-CFM) or Dynamic Cascading Failure Modelling (Dy-CFM). Next, the user needs to specify the type of events for study, either non-weather-related events (enter 1) or weather-related events (enter 2). Subsequently, the tool requests the number of concurrent outages (k) for the N-k contingency analysis, allowing the user to customize the analysis, for example, by entering k equal to 2 for N-2 contingencies.

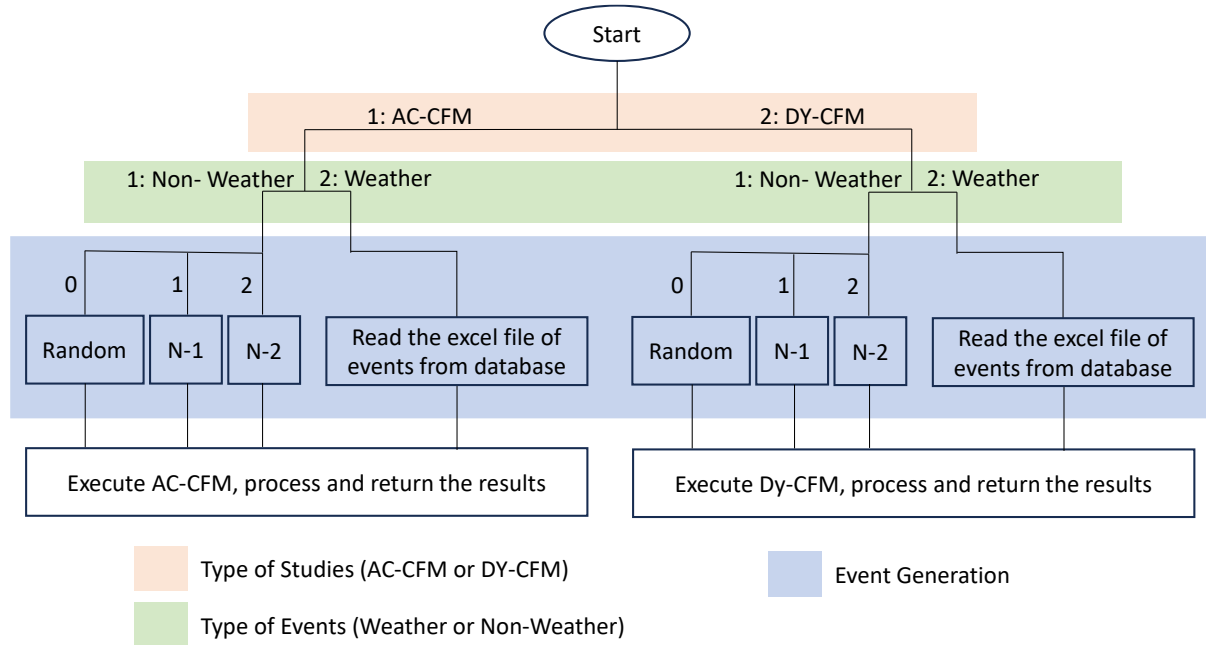


FIGURE 18: WORKFLOW DIAGRAM OF THE CASCADE MODELLING TOOL.

Resilience model and data:

The resilience-based modelling of power systems may vary according to different types of studies, including static and dynamic analyses, from various standpoints on the phases of the resilience trapezoid, covering disturbance progression, post-disturbance degraded state, and restoration. According to the project's targets, the associated modelling for resilience studies primarily focuses on the degradation or disturbance progression phase caused by the initiation and propagation of cascading failures, thus highlighting cascading-driven resilience assessment. It can then be complemented by the restoration phase described in Section 3.2.4.

To capture the transient behaviours and responses of the system following a disturbance, especially through the incorporation of relevant controllers and protection relays, the dynamic modelling must be considered using time-domain RMS simulation. The dynamics and mechanisms involved in the cascading-driven resilience assessment of power systems are conceptually represented in Figure 19. The modelling incorporates controllers and protective relays such as generator AVR and governor, over/under frequency generator tripping, undervoltage and underfrequency load shedding relays, as well as thermal or overcurrent relay of lines [7], [8].

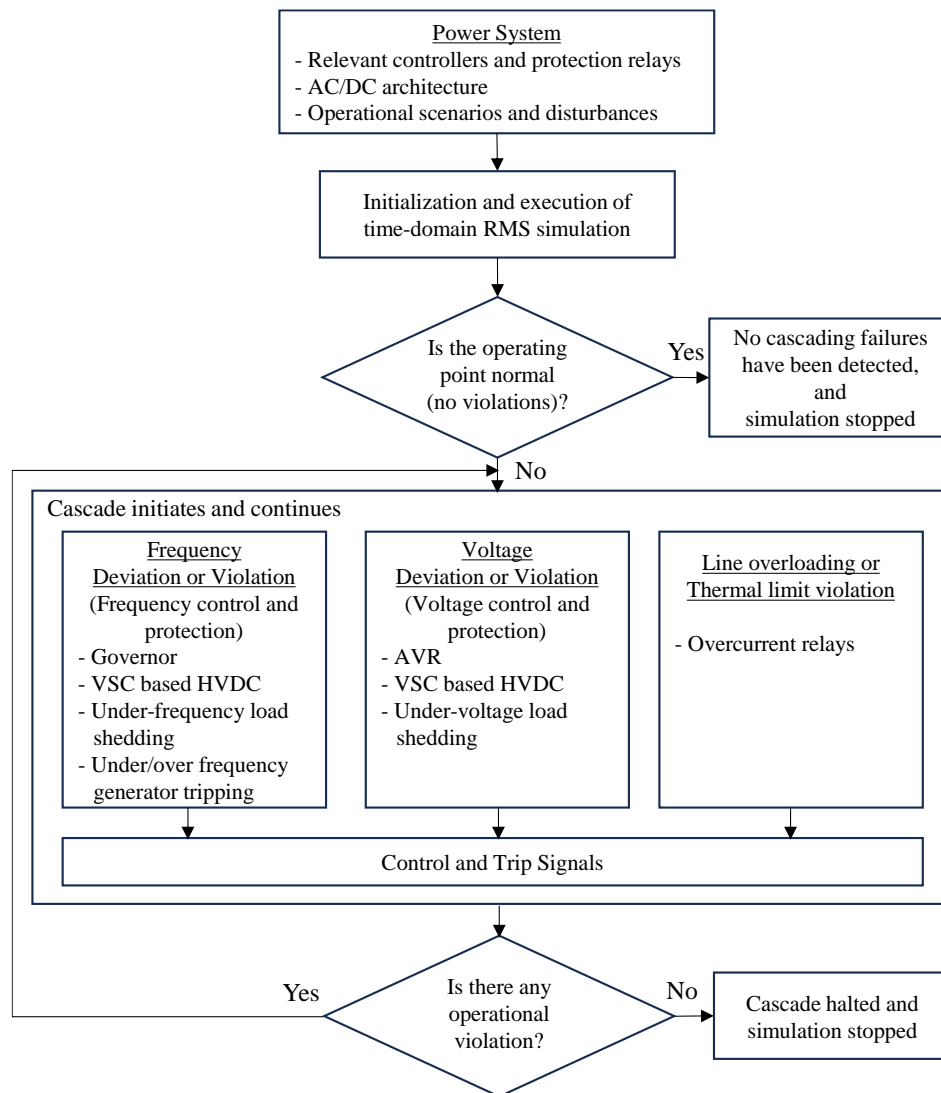


FIGURE 19: CONCEPTUAL REPRESENTATION OF DYNAMIC MODELING OF CASCADING FAILURES THROUGH TIME-DOMAIN RMS SIMULATION

In addition, the data needed for resilience studies includes geographical coordinates of the power grid, historical wind event data, and the grid's static and dynamic parameters. As mentioned earlier in Section 3.2.3, the event simulator is employed to generate resilience events by simulating and returning different scenarios of weather-related events, including the status of all lines in hourly time slots. Figure 20 shows the overall framework of the fragility-based wind event simulator, which can be utilized to derive the time- and weather-dependent status of network lines affected by a windstorm. The framework simulates weather-related events and generates the status of network lines affected by a windstorm, involving input data, event modelling, and impact analysis.

The input data for the simulator is prepared in stage 1, including network branch and node data along with their geographical latitude and longitude, fragility curves of transmission lines, and historical event data. Fragility curves, representing the relationship between hazard intensity (e.g., earthquake or windstorm) and the probability of damage to specific infrastructure, are employed. These curves can be derived through various methods, including statistical analysis, experimentation, simulation-based approaches, expert judgments, or a combination of these. In this study, fragility curves for transmission lines are utilized, as outlined in [9], to model the wind-dependent failure probability of

these lines. To generate realistic wind events, the model in stage 2 extracts windstorm characteristics from historical data, considering parameters such as wind gust speed and windstorm radius. Using Monte Carlo simulations, a comprehensive set of windstorm scenarios is generated. Subsequently, in stage 3, the simulator maps the intersection of the windstorm with the lines, and the affected line status is determined based on the fragility curves and failure probability. In the last stage, the simulator outputs all scenarios of wind events, including the status of all lines in hourly time slots. Here, the decision to trip a line that comes under the intersection of windstorm is taken based on Equation (3).

$$LS(w_{st}, l) = \begin{cases} 1 & \text{if } P_L(w_i) < r \\ 0 & \text{if } P_L(w_i) > r \end{cases} \quad (3)$$

where, LS is the network line status, w_{st} is the wind intensity or wind speed at step i , P_L is the wind-dependent failure probability, and r is a random number generated from a uniform distribution between 0 and 1. The concept of r is introduced in this procedure to add more stochasticity to the model.

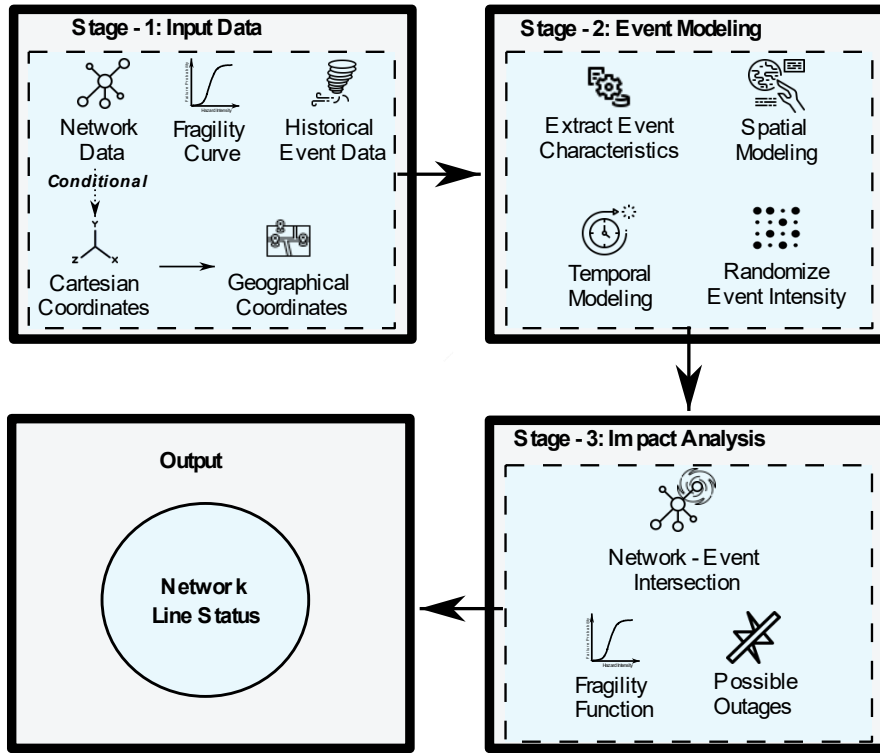


FIGURE 20: OVERALL FRAMEWORK FOR SIMULATING WEATHER-RELATED EVENTS

Resilience analysis:

This part of the methodology introduces system resilience assessment by quantifying the impacts of both expected and tail-risk events, which may range from a single set to multiple sets of concurrent events, on AC/DC systems. Focusing on the degradation phase of the resilience trapezoid while neglecting time from the metrics—especially for fast cascades—this evaluation can be conducted using risk-driven metrics such as Expected Value, Value-at-Risk (VaR), and Conditional Value-at-Risk (CVaR) to quantify cascading impacts involving a large set of disturbances.

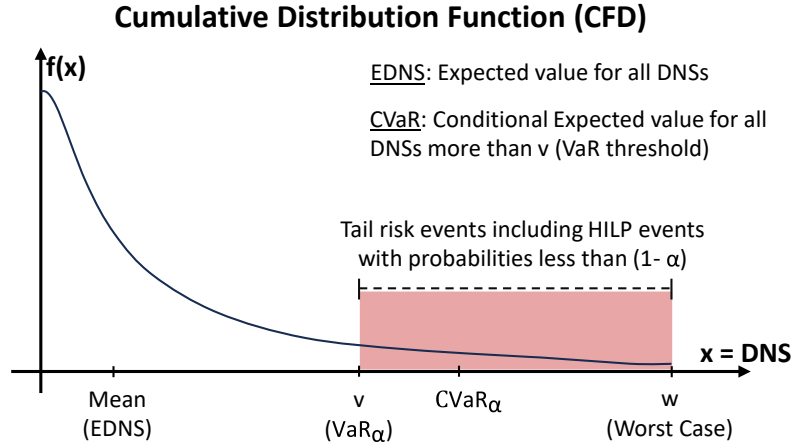


FIGURE 21: RISK MEASURES – MEAN, VAR, AND CVAR FOR DEMAND-NOT-SERVED (DNS)

It may be misleading to quantify resilience metrics by a single value (typically the average or expected value) over an extended period or for various scenarios (including both low-impact high probability events, and high-impact, low-probability events). Instead, they are often characterized by probability distribution functions or density functions and cumulative distribution functions that allow the quantification of average/expected values as well as conditional values of the selected resilience metrics. An illustration of such a distribution for demand not served as an example of a resilience metric is given in Figure 21.

In the resilience assessment of power systems, in order to focus on the quantification of the very extreme scenarios, the worst contingencies with probabilities less than $(1 - \alpha)$ are considered, where $1 - \alpha$ represents the cumulative probability of all High-Impact, Low-Probability (HILP) outcomes lying in the tail of the Cumulative Distribution Function (CDF) in Figure 21. Various metrics can be derived from probability or cumulative distributions to condense the information into a few values, facilitating the comparison of results before and after implementing resilience enhancement or mitigation strategies.

Two such metrics are Value at Risk (VaR_α) and Conditional Value at Risk ($CVaR_\alpha$), used to measure power system resilience, and in particular the so-called “tail risk” events. VaR_α measures the maximum loss of load for events beyond a prespecified risk threshold, α , while $CVaR_\alpha$ measures the conditional expectation of a loss of load for such events [10], [11]. As mentioned earlier, $VaR_\alpha(x)$ in Figure 21 represents the minimum value of x (where x is defined as DNS) lying in the worst $(1 - \alpha)\%$ cases, or it denotes the value x for which $f(x) \geq 1 - \alpha$, with α being the selected confidence level (e.g., 90% or 95%). Additionally, CVaR at level α , denoted as $CVaR_\alpha(x)$, is the expected value of x (where x is defined as DNS), given that all the DNSs exceed the VaR threshold:

$$CVaR_\alpha(x) = \frac{1}{1 - \alpha} \int_{f(x) \geq 1 - \alpha} x df(x) \quad (4)$$

To perform cascading-driven resilience analysis based on dynamic studies, time-domain RMS simulation is required. After applying disturbances to the AC/DC power grid equipped with relevant controllers and protection relays, the simulation continues until the ongoing cascading propagation comes to a halt. Then, the defined metrics, quantifying the cascade extent and severity, are calculated.

3.2.4 Tool to assess the impact of HVDC systems on power system restoration

After a partial or full power system black-out, it is essential to restore the power system in a fast and effective way in order to minimise the negative impact on the customers. The restoration itself is a complex procedure in which an optimal sequence of network energisation path needs to be defined to interlink black start (BS) energy sources to the other units (providing the required cranking power) in order to re-energise the remaining network and restore the connected load.

As highlighted in the previous section, the tool for cascading event quantification mainly focuses on the disturbance progression phase, caused by the initiation and propagation of cascading failures, as well as the post-disturbance degraded state within the so-called resilience trapezoid, which is shown in Figure 22 below. As such, it provides a way to assess the resilience KPIs up till the start of the restoration, but is not able to define the system performance, just as the other tools in the project, during the restoration itself.

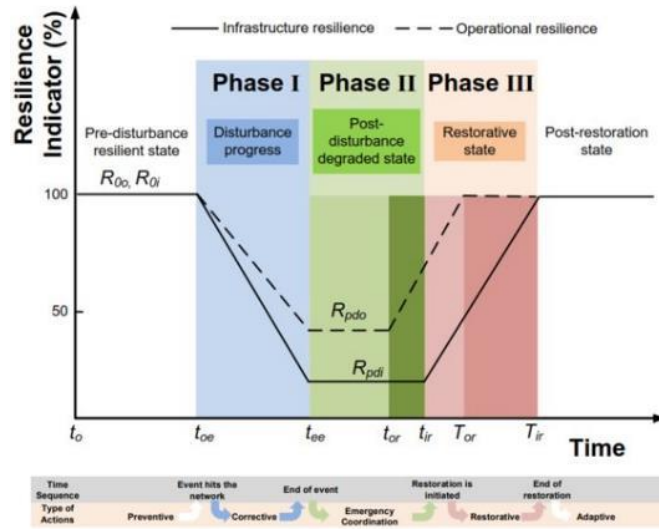


FIGURE 22: RESILIENCE TRAPEZOID [12]

However, contrary to how it is depicted in the figure, the restoration phase takes typically much more time compared to the other states within the resilience trapezoid. Hence, it will have a significant impact on the main key resilience performance indicators such as ENS. To fully assess the operational resilience of a system, from start of the event(s) to a restored system, and complement the existing toolset within the project, it is therefore important to develop a tool that can provide a quantitative view on the system restoration performance as well as compare the impact on the decisions made in the planning of the future black-start generation assets and the power system network, especially looking at the location and design of different AC/DC architectures. Regarding HVDC systems, it is generally well documented that they can provide great benefits during power system restoration. In fact, black-start is also usually listed as one of the main benefits the Voltage Source Converter (VSC) HVDC technology can provide.

Therefore, to address this need, a restoration tool is developed in the scope of this project which build upon the existing work in the literature by not only considering the restoration of AC networks with conventional means, but also assessing the capability, application and overall impact on the resilience metrics (i.e., ENS) of applying HVDC systems within the restoration procedure.

In the following, a short description of the tool is given and its application to a small test case is presented. Finally, also the link with the other tools and its application on the use cases is elaborated.

High-level description of the tool

In a restoration problem, the aim is to re-energize the network and restore the loads of the system as quickly as possible. This main objective is expressed in the tool as an optimisation problem minimising the ENS. It is written as follows:

$$\min \sum_{i=1}^T \sum_{\ell \in \mathcal{L}} (P_{target,\ell,i} - P_{\ell,i}) \quad (5)$$

where $P_{target,\ell,i}$ is the nominal power consumption of load ℓ , and $P_{\ell,i}$ is the load supplied at time step i . T is the horizon of the optimization, and has been split into several discrete time steps, $i = 1, 2, \dots, T$.

Different approaches and level of details can be taken to extend the formulation of this optimisation problem and associated constraints. Here, the focus is on evaluating the restoration using a MILP formulation, integrating a simplified modelling of the AC network and of the HVDC equipment, namely VSCs, as they are expected to improve the restoration. As such, the developed tool is applicable to multiple use cases in the context of HVDC-WISE and efficient enough for multiple events and long-term assessment.

To achieve an optimal (i.e. quick) restoration of the loads, the optimization will identify an optimal sequence of actions defined by the following control variables:

- Status of branches, buses, and generators
- Active and reactive power of generators
- Status and reactive power of shunt reactors
- Active power consumption of loads

The following constraints are imposed to obtain an adequate representation of the power flows (in line with the modelling of [4]) and to ensure that the main system variables remain within their operational limits:

- Power balance between generation and load;
- Linearised Kirchhoff laws for active and reactive power;
- Voltage must remain within defined limits;
- The flow through a line must respect the line rating;
- Generator active power output must remain below the maximum machine capability P_{max} . Ramp-up and cranking power constraints must also be respected.

Additionally, it is important to note that the network reactive power absorption capability is often a limiting factor during the first steps of the restoration. Just after their energisation, the lines are lightly loaded, which leads to non-negligible reactive power injection. Therefore, additional inequality constraints have to be included controlling the reactive power balance at each bus, as presented in [4]. This inequality constraint intends to ensure that the network can absorb the reactive power at each step of the restoration.

Beyond the network equations, some constraints are set regarding the energisation process. These rules apply to buses, branches and generators status. It is assumed that once energised, buses, branches and generators remain energised. Furthermore, the model ensures that the generator ramp-up constraints are respected and the restored load is monotonic at all nodes.

It should be noted that the restoration process is considered to start after the energisation of the BS units. The restoration is discretised in a pre-defined number of time steps. The first time step is just after energisation of the BS units and associated buses. Finally some constraints are defined to control asset energisation. These constraints state that:

- A bus can be energised if one of its adjacent branches is energised;
- A branch can be energised if one of its buses is energised;
- An NBS generator can be energised if its connection bus is energised.

Regarding the modelling of HVDC interconnections, this work makes some simplifications to integrate them in the overall formulation: the losses in the DC grid and converters are neglected, which is in line with the AC system modelling, and the VSCs are represented as equivalent generators. The following active power balance applies for all VSCs of the same HVDC grid, where \mathcal{G}_{DC} denotes the DC grid.

$$\sum_{vsc \in \mathcal{G}_{DC}} P_{vsc} = 0 \quad (6)$$

Furthermore, it is stated that a VSC can exchange power with its DC grid only if it is energised. The energisation rules of a VSC are the following:

- VSC can be energised if its AC connection node is energised (AC-side energisation);
- VSC can be energised if another VSC of the same DC grid is energised (DC-side energisation).

It is worth mentioning that two types of converters are considered which will impact the actions the VSC can take.

1. Black-start VSC (BS VSC): this VSC has black start capabilities, i.e. if it is energised (by the DC grid), it can energise its AC bus.
2. Non-black-start VSC (NBS VSC): it cannot energise its AC bus. Its AC bus must be energised throughout the energisation of the AC network.

The model presented supports the following HVDC configurations:

- Embedded point-to-point HVDC link: the HVDC link connects two buses, belonging to the same synchronous grid.
- Asynchronous point-to-point connection to an external system: the external AC system can be modelled either as an equivalent black-start generator if there is an agreement between the two systems to provide black-start support or as an NBS generator, if there is no such agreement or capability in place (e.g. if the external system represents an offshore wind farm).
- Multi-terminal HVDC system, which could be fully embedded, asynchronous, or a mix of the two.

Example using a small test system

To demonstrate the tool and evaluate the possible benefits brought by HVDC technology in the network, the IEEE 39-bus system is used as a starting point, see Figure 23. In this case, the only black start unit is located at bus 30.

An additional embedded point-to-point HVDC interconnection has been added to the network, which is represented by a dashed red line. The HVDC link is chosen such that it connects two electrically distant buses, one of which is close to the black start generator and the other close to one of the biggest load centres of the network. As mentioned before, the VSCs are not modelled in detail and are just represented as two equivalent generators. For this test case, the two VSCs have each a maximum active power capacity of 600 MW.

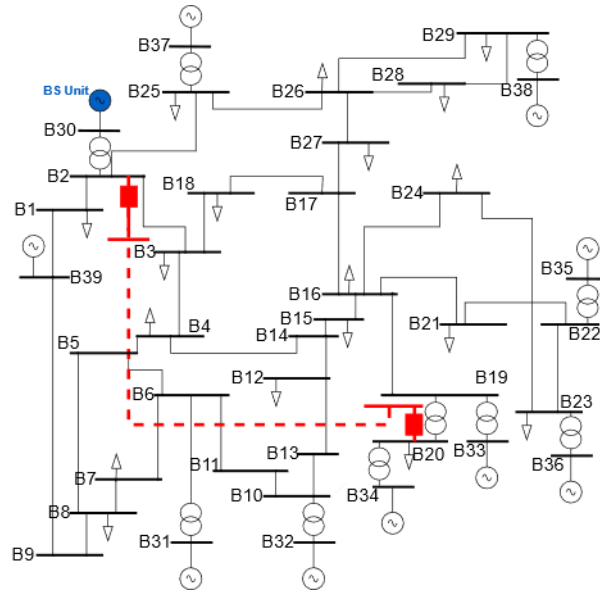


FIGURE 23: IEEE 39 TEST CASE INTEGRATING AN EMBEDDED POINT-TO-POINT HVDC LINK

The results of the test case are presented in Figure 24 below. The situation with a BS VSC has a positive impact on the load restoration speed. This can be evaluated thanks to ENS which is 9% lower in the case with a BS VSC (131 GWh instead of 144 GWh without BS VSC). In Figure 24 (b), the power transfers over the VSC are shown (from B2 to B20 is taken as the positive direction). In case of the NBS VSC, the network at both ends of the interconnection needs to be energized first before power is exchanged. Instead, looking when the VSC is considered a BS VSC, the link is used to provide cranking power at the start of the restoration process from the main BS unit to the units at the other side of the network, enhancing the speed and performance (i.e. reduced ENS) of the restoration process.

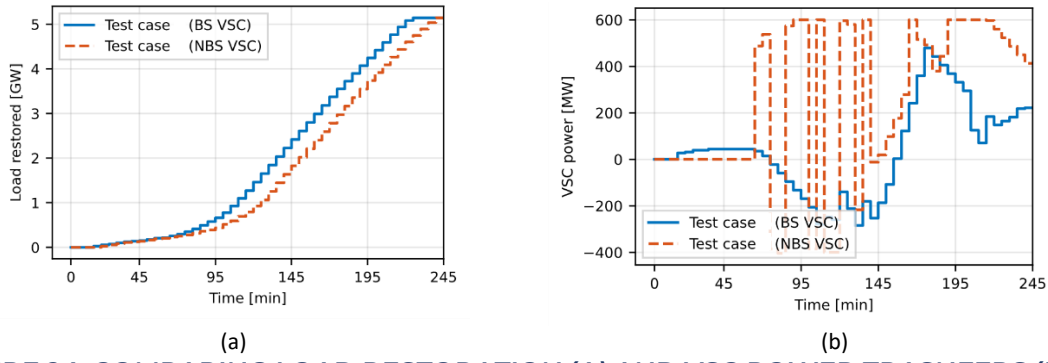


FIGURE 24: COMPARING LOAD RESTORATION (A) AND VSC POWER TRANSFERS (B) FOR THE TEST CASE CONSIDERING VSC AS BS AND NBS

Link with other tools and application to the use cases

Within HVDC-WISE, the restoration tool will be closely coupled with the tool for cascading event quantification and operational mitigation strategies (see section 3.2.4) as the output of this tool will be applied as input/starting point of the restoration process. More specifically, the cascading event tool will determine the network state and operating point right before the restoration will start. As the restoration tool only applies a simplified representation of the network and power flow equations (moreover dynamic phenomena during energisation are for instance not assessed), only a subset of the data applied in the cascading event tool is transferred. Finally, assumptions are made, based on the literature, for the additional parameter values required for the restoration tool, such as the cranking power of each unit, the time delays in the network energisation, etc. The tool will be used within use case 2 since the size of the system is manageable by the tool (computational burden of the MILP that needs to be solved) and due to the fact that also the cascading event tool will be primarily applied within this use case 2.

3.3 Key Indicators

Depending on the types of studies intended for each use case, a variety of indicators are available, as extensively described in D2.2, and can be calculated using the toolset. These key indicators, as outlined in the following subsections, encompass TEA/adequacy indicators, static and dynamic security indicators, and resilience indicators.

3.3.1 TEA/Adequacy Indicators

As presented in D2.2 [13], adequacy indicators EENS and LOLE can be computed with zonal or nodal OPF. The latter approach is more accurate. These indicators can take into account HVDC dissymmetric operation in case of partial outage, and long-lasting impacts of extreme events on infrastructure, possibly affecting adequacy.

The Socio-Economic Welfare (SEW) can be evaluated with zonal or nodal analyses. Losses and CO₂ emissions can be evaluated ex-post. Curtailed RES generation, another KPI typically assessed in CBA of transmission projects, is a direct outcome of the OPF. Finally, the energy transferred by the HVDC links/grids, though not directly involved in CBA, can be regarded as an interesting indicator of the “effectiveness” of the HVDC links/grids. This indicator can be computed as a post-processing of OPF results.

Of course, these indicators are computed for each HVDC architecture under analysis, and they are expressed as “absolute” values that allow to perform comparisons between different architectures (with the aim of candidate ranking) or to assess incremental quantities (within the scope of “with and without” analyses), within the context of CBA.

It can be observed that evaluations of CO₂ emissions, EENS, and wind curtailment directly contribute to project KPIs (#1, 2, 6 respectively). Moreover, LOLE can be adopted as a proxy of CAIDI for KPI #3 regarding customer total interruption duration, and EENS can be used as a proxy of customers interrupted (as EENS / average primary substation load) in KPI #5 regarding customers interrupted. KPI #7 on additional wind capacity can be indirectly computed, via application of the tool with different input scenarios and by setting a suitable methodology and criteria (e.g., specifying the other KPIs on which this KPI is based).

3.3.2 Static and Dynamic Security Indicators

The security of a power system refers to the ability to withstand potential disturbances without an interruption of electricity supply. It refers to the robustness of the system against potential disturbances and it is therefore dependent on the operating status of the system. The stability of a power supply system refers to the ability to maintain intact operation after a fault. It depends on the operating conditions and the type of physical fault [6].

Static security analyses

Involving steady-state analysis of system conditions to ensure that no thermal ratings or voltage constraints are violated.

- Line Overloads (Frequency / amount of overload)
- Voltage Band Violations (Frequency / level of violations)
- Reactive Power Losses
- Active Power Losses

Dynamic security analyses

Involving the assessment of various stability indicators.

- Rotor Angle Stability (Violation of the FRT capability curves, voltage angle differences, displacement of the rotor angles, tripping of machines)
- Frequency Stability (Rate of Change of Frequency, Nadir/Zenith Frequency)
- Voltage Stability (Bus voltages)

3.3.3 Resilience Indicators

As extensively described in D2.2 [13], a wide range of resilience KPIs, including both attribute-based and performance-based metrics, can be defined and utilized depending on the type of studies and the resilience phase. Table 5 outlines these resilience KPIs, which can be employed to quantify system

degradation resulting from cascading failures [14]–[17], and compare them based on quasi-steady-state (QSS) and dynamic modelling approaches and studies. Except for the KPIs related to frequency response, which are provided below and can be derived from dynamic simulations, the other KPIs can be similar for both QSS and dynamic studies.

TABLE 5: RESILIENCE KPIS

Resilience Phase	Resilience KPIs		Type of Study	
			QSS	Dynamic
System Degradation	Cascade Severity	Probability distribution of DNS	✓	✓
		(average, VaR, and CvaR values)		
	Grid Integrity	Frequency and Probability Distribution of outages	✓	✓
		Frequency and Probability Distribution of system splits	✓	✓
	Cascade Speed	(mean number of line outages in iteration k) /	✓	✓
		(mean number of line outages in iteration (k-1))		
	Cascade Spatiality	Probability distribution of the network distance of successive outages	✓	✓
	Protection Operations	Probability distribution of protection relay operations	✓	✓
	Frequency Response	Probability distribution of ROCOF	–	✓
		Probability distribution of Frequency Nadir	–	✓
System Restoration	Total Restoration Time		✓	✓
	Energy-Not-Served (ENS)		✓	✓

3.3.4 Index processing

According to the methodology's flowchart in Figure 12, the last stage is to prioritize different reinforcing design options for HVDC-based grid architectures. To do so, the calculated KPIs at the end of the assessment must give indications on how further improvements can be made by comparing different AC/DC network development proposals. For example, within the context of HVDC-WISE, these proposals, as outlined in D2.2 [13], could include various options such as a new HVDC link, the interconnection of existing HVDC systems, the addition of an HVDC link to an existing HVDC link/grid, or a new HVDC grid. As per D2.2 [13], the graph depicted in Figure 25 conceptually illustrates this

process for one network development proposal and two options. In the overall R&R assessment of each option, a definition of weights (w_i) corresponding to the calculated KPIs might be required. These weights may vary depending on each use case.

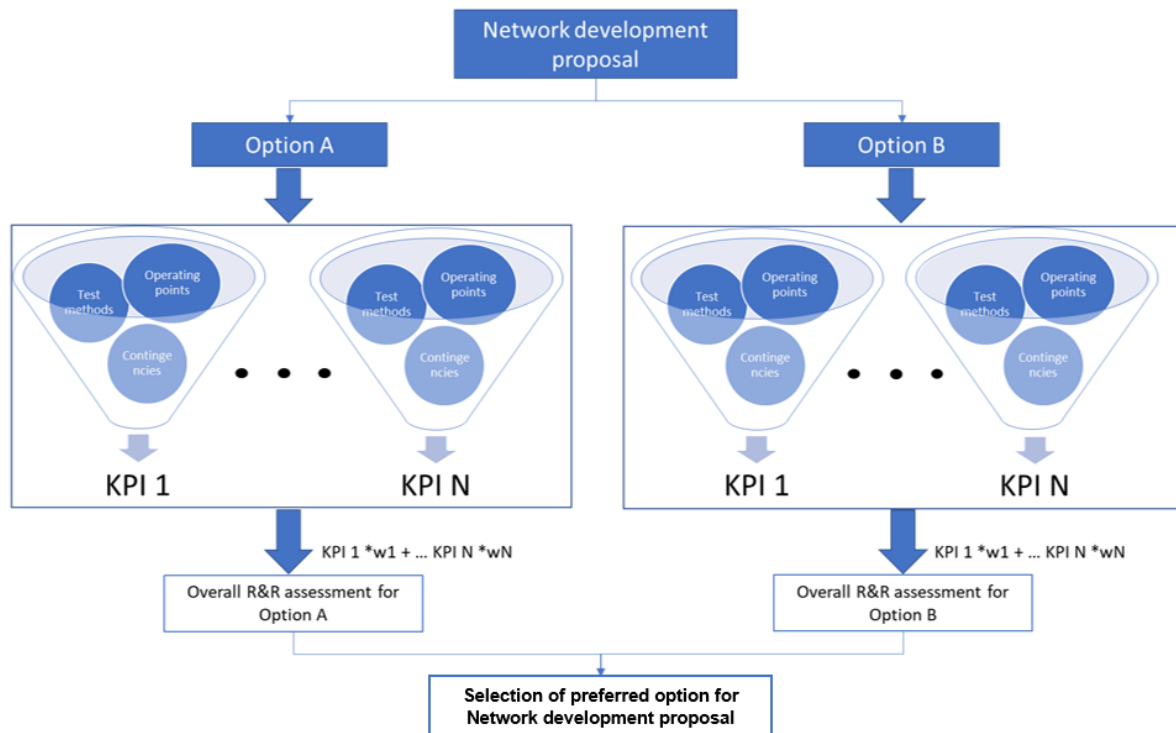


FIGURE 25: CONCEPTUAL DEPICTION FOR R&R ASSESSMENT OF NETWORK DEVELOPMENT PROPOSALS

4. Use case application of methodology

This section describes how the three use cases that will be used in the project will each demonstrate aspects of the reliability- and resilience-oriented methodology for HVDC based network reinforcement. To this end, each of the three use cases, with their different nature and focus areas outlined in Section 2.1, expands on their intended approach to demonstrating the methodology or aspects of it through the toolsets available to the project partners within the respective use cases. Consideration is given to the network representation, data inputs and assumptions required for each stage of modelling, the specific modelling platforms that will be used and the types of operational scenarios and disturbances that the use case will focus on.

4.1 Use case 1

In Use Case 1, the reinforcement of the continental European grid is analysed. Therefore, market simulations are performed to derive time series of generation dispatch, flexible demand and interconnector transfers. Static analyses with different HVDC configurations are performed and used as input for the dynamic assessment of capabilities and benefits of differently configured HVDC systems.

4.1.1 Use case workflow

The overall workflow from Use Case 1 is shown Figure 26. On the basis of the underlying scenario parameterisation (time series for load demand, feed-in from RES, European thermal and hydraulic power plant portfolio) a European market simulation provides the initial dispatch of the power plants for the subsequent grid calculations in addition to the market-related KPIs.

The subsequent security assessment within the toolchain is based on an initial AC power flow calculation. The hourly feed-in and demand per grid node from the previous results of the regionalisation, time series generation and market simulation are considered within the power flow calculation to determine the initial utilisation of the transmission lines and corresponding bus voltages.

Based on the initial power flow calculation, optimal power flow calculations are carried out. By optimising the grid operation measures as part of the optimal power flow calculations, an optimised set of measures can be determined for cost-efficient grid operation while at the same time meeting the operational and physical requirements.

Afterwards based on the steady state grid data, dynamic time domain simulations are carried out to analyse various stability phenomena.

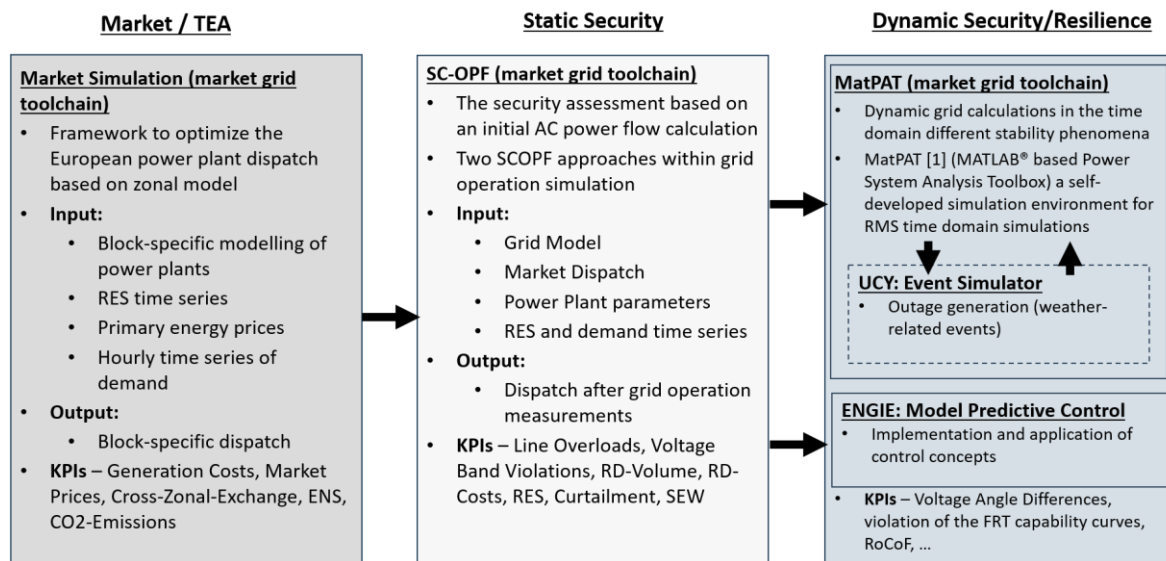


FIGURE 26: USE CASE 1 WORKFLOW

4.1.2 Market simulation

The market simulation provides a framework to optimize the European power plant dispatch for the considered scenario (time series for load demand, feed-in from RES, European thermal and hydraulic power plant portfolio) and thereby determines the supply task underlying the grid operation simulations. The framework of the market simulation will be explained in the following.

Input Data

The market simulation is in general based on the previously defined generation and demand scenario. In particular, the following parameters serve as input data for the market simulation:

- Block-specific modelling of large thermal and hydraulic power plants
- Maximum output, primary energy source used, machine type (gas turbine, steam turbine, gas and steam turbine), availability, heat consumption curve, minimum output, minimum operating and downtimes and start-up costs of all thermal power plants
- Basin sizes, inflows and machine type of (pumped) storage power plants as well as efficiencies and maximum flow rates for pumps and turbines
- Hourly and spatially resolved time series of generation from combined heat and power plants as well as generation from wind turbines, photovoltaic plants, run-of-river power plants
- Hourly time series of demand for electrical energy and flexibility potential of demand (incl. maximum shift duration)
- Primary energy prices (including transport costs and taxes) and prices for CO₂ emission certificates
- Detailed mapping of the European bidding zones
- Restriction of exchange capacities using net transfer capacity (NTC) values between bidding zones

Based on the input data, the general objective is to simulate the European electricity market.

Market simulation process

The determination of the cost-minimised European power plant dispatch is a complex optimisation problem. Due to discrete decisions in the context of thermal power plants and temporal coupling of hydraulic generation plants and groups requiring the use of integer variables, advanced methods and approaches to adequately solve the problem for the simulated planning year are required.

Therefore, a decomposition approach based on Lagrange relaxation is used. The constraints considered result, for instance, from load coverage, available transmission capacities between market areas and technical restrictions of generation plants and storage facilities.

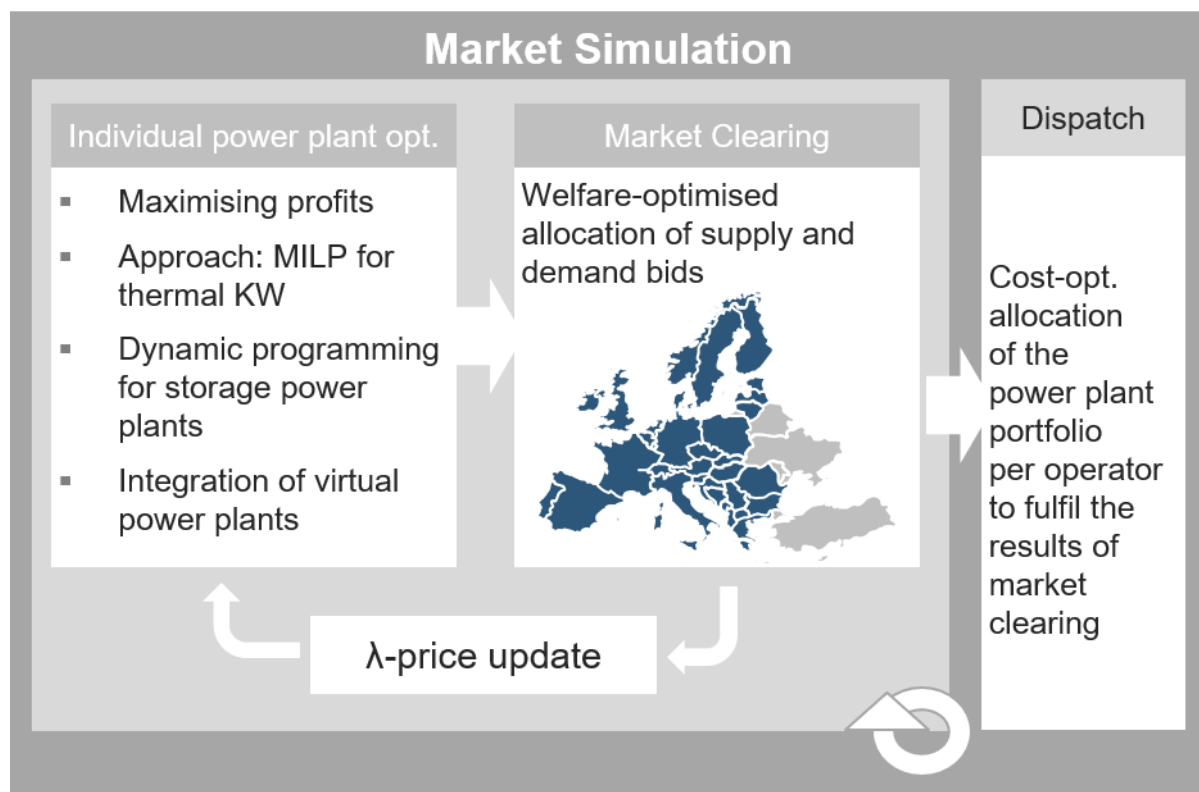


FIGURE 27: LAGRANGE-BASED CROSS-MARKET AREA OPTIMISATION OF THE EUROPEAN ELECTRICITY MARKET

One key element of the applied method is a Lagrange decomposition and relaxation. This approach enables decomposition in both time and system domains. The subsequent iterative solution of the resulting sub-problems is coordinated with the help of Lagrange coordinators λ so that an overall optimal solution can be determined.

Technology-specific methods are used to solve the sub-dispatch-problems thermal generation units, storage units and demand side management processes. The determined optimal start-up and operating decisions for generation plants and storage facilities are transferred to the subsequent process step, in which the operating points are determined, and the cross-border exchange is redetermined.

To model the operational behaviour of central thermal and hydraulic power plants, many technical characteristics are considered in the electricity market simulation. The following technical properties are regarded modelling thermal power plants:

- Min. electrical power
- Min. and max. efficiencies
- Min. operating and downtimes
- Start-up and shut-down times
- Power gradients
- Cold, warm and hot start costs

With regard to the modelling of hydraulic power plants, the following technical characteristics are considered:

- Pump and turbine output
- Efficiencies
- Maximum storage volumes of the reservoirs

To ensure the consistency of the market clearing prices and the exchange between market areas, a simplified modelling of the EUPHEMIA market coupling algorithm is used within the market simulation, which only considers linear acceptance rates of bids by power plant, renewables, storage, demand, etc. in each time step. The respective bid quantity is derived from the power plant schedules, while the bid price is based on the marginal generation costs or the Lagrange multipliers in the market area. In addition to the assumption related to the bids of the market participants, the exchange between market areas results from the market coupling. The market clearing price of each market area is derived from the dual solution of the market coupling optimisation problem.

The results of the electricity market simulations are the hourly resolved schedules of the block-specific generation units and storage facilities, the trading balances of the market areas under consideration, the generation costs, and the resulting market prices. Based on this information, the overall systemic results in relation to the different topologies to be analysed in the study can be derived and evaluated.

TABLE 6: KEY PERFORMANCE INDICATORS DERIVED FROM THE MARKET SIMULATION

Key Performance Indicator	Unit	Short Description
Generation Costs	[€]	Costs of the energy generation
Market Prices	[€]	Resulting bidding zone-specific market prices
Cross-Zonal-Exchange / Cross-Zonal-Capacity	[%]	Remaining exchange capacity after cross-bidding zone market exchange
Energy Not Served	[MWh]	Market area-specific load undercoverage
CO ₂ -Emissions	[t/MWh]	Resulting CO ₂ -Emissions from energy generation

4.1.3 Security assessment

The security assessment is based on an initial AC power flow calculation. Considering the hourly feed-in and demand per grid node from the preceding results of the regionalisation, time series generation and market simulation, the power flow calculation determines the initial utilisation of the transmission

lines and bus voltages, and the grid losses incurred. The power flow calculation includes the lines and transformers of the European transmission grid and is carried out with an hourly resolution.

Grid Operation

Based on the initial power flow calculation, optimal power flow calculations are carried out for the selected area under consideration. By optimising the defined degrees of freedom available during grid operation within the framework of the optimal power flow calculations, an optimised set of measures can be determined for a cost-efficient grid operation while at the same time ensuring compliance with operational and physical limits and restrictions during normal operation (n-0) and in outage situations (n-1).

Within the scope of the analyses, two approaches of the security constrained optimal power flow calculation are carried. One modelling approach in particular offers the possibility to derive converter set points and operating concepts of MT-HVDC systems. Furthermore, a second modelling approach offers the possibility to consider voltage control and stability in the context of power flow optimisation.

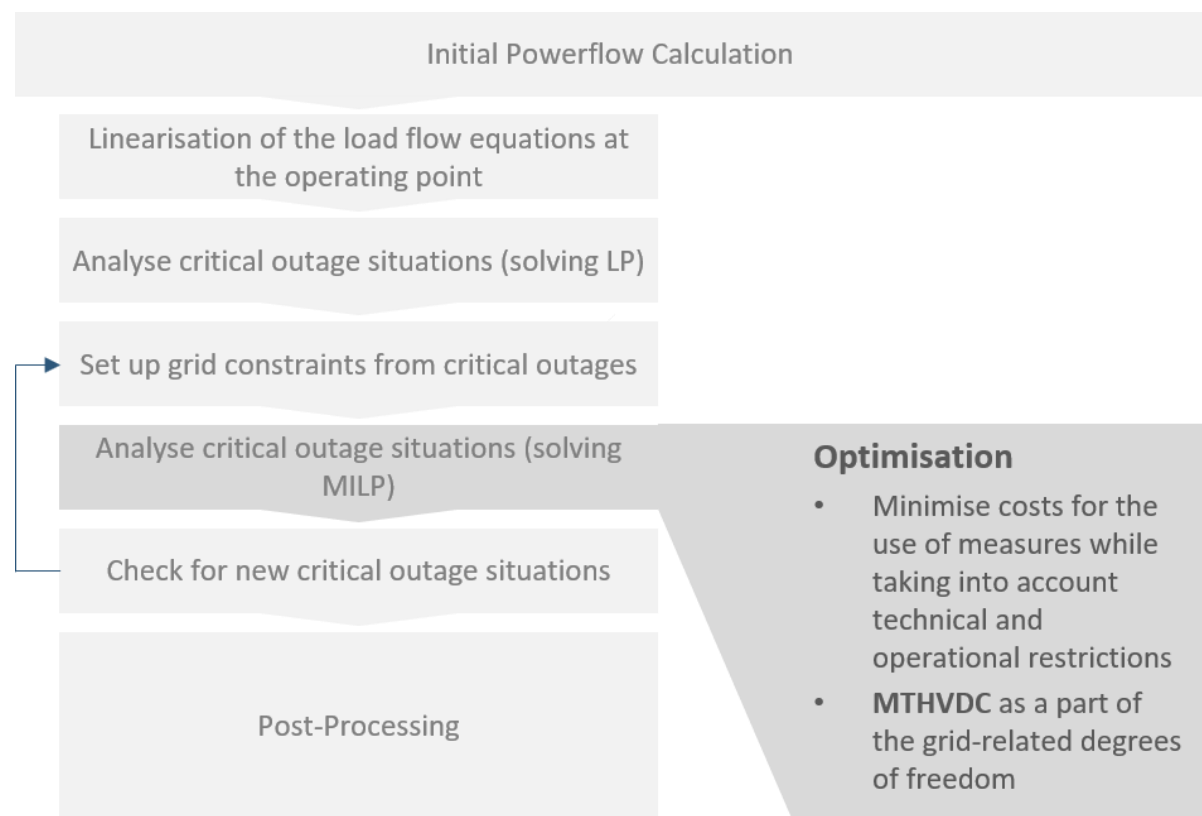


FIGURE 28: GRID OPERATION SIMULATION TO MINIMISE OPERATIONAL COSTS AND DERIVE OPERATIONAL CONCEPTS OF MT-HVDC SYSTEMS

In this context, Figure 28 provides an overview of the methodology to determine an optimised set of grid operation measures and the determination of operational concepts for MT-HVDC systems within the grid operation simulation.

Based on the initial power flows determined, a congestion analysis and outage simulation are carried out to identify overloads or (n-1) violations. The (n-1) criterion is applied and evaluated using linear, flow-based sensitivities. The congestion analysis is based on the thermal current limit values of the

lines and the power flows determined in the (n-1) case. As a result, the congestions in the transmission grid are quantified. Various congestion indicators can be evaluated, e.g. the maximum (n-1) utilisation of each line, the number of hours in which a line is overloaded or the sum of all overloads within an hourly simulation of the considered simulated planning year.

As part of the grid operation simulation, the amount of redispatch and other congestion management measures required to resolve all congestions and to restore a (n-1)-secure system state in the considered transmission grid area is determined. Thereby a linear sensitivity approach to represent the changes in power flows due to outages or congestion elimination measures is used. The model is formulated as a mixed-integer linear optimisation problem and identifies the cost-optimal congestion management requirements. Taking regulatory framework conditions into account, grid-related degrees of freedom are prioritised in the optimisation, if possible, to eliminate congestions. Market-related degrees of freedom, such as the utilisation of conventional redispatch, are then afterwards used. The model is based on an iterative process for the successive expansion of the considered outage variant list. After each optimisation with a given list of critical outage variants, a new outage simulation and check for grid congestions is performed. If no new congestions are identified after an iteration, the termination criterion of the iterative process is fulfilled, and the resulting results are stored. The results of the congestion management simulation include the preventive and curative (optional) use of measures for each unit/ technology and each hour of the planning year. These include, for example, conventional redispatch measures, RES curtailment, cross-border redispatch, phase-shifting transformer control, HVDC control and the use of decentralised flexibility.

In a second method, in addition to the optimisation of the active power flows, the degree of freedom for voltage control and the provision of reactive power are optimised as part of the optimal power flow. In particular, the degrees of freedom provided by the HVDC systems for adapting the active power transmission and for supplying lead reactive power to the AC grid are considered. Figure 29 provides an overview of the corresponding methodological approach.

After the initial power flow calculation and based on an initial outage simulation, a step-by-step linearisation of the load flow equations and solution of the optimisation problem is carried out in a successive linear programming (sLP) approach. During this process, the sensitivity of the change in the operating points of the grid equipment and generation units on the line utilisation and bus voltages can be determined based on the Jacobian matrix. Based on these sensitivities, the use of measures and in particular the use of redispatch measures and voltage control actions can be optimised.

The step-by-step linearisation represents a necessary simplification of the underlying physical laws to realise an efficient calculation process for the optimisation and at the same time address the non-convexity and non-linearity (especially with the integration of voltage-related variables) of the optimisation problem. In the course of this successive approach, the result of the optimisation is verified by a power flow calculation and, if line overloads or voltage band violations remain, the procedure is repeated iteratively until the process converges.

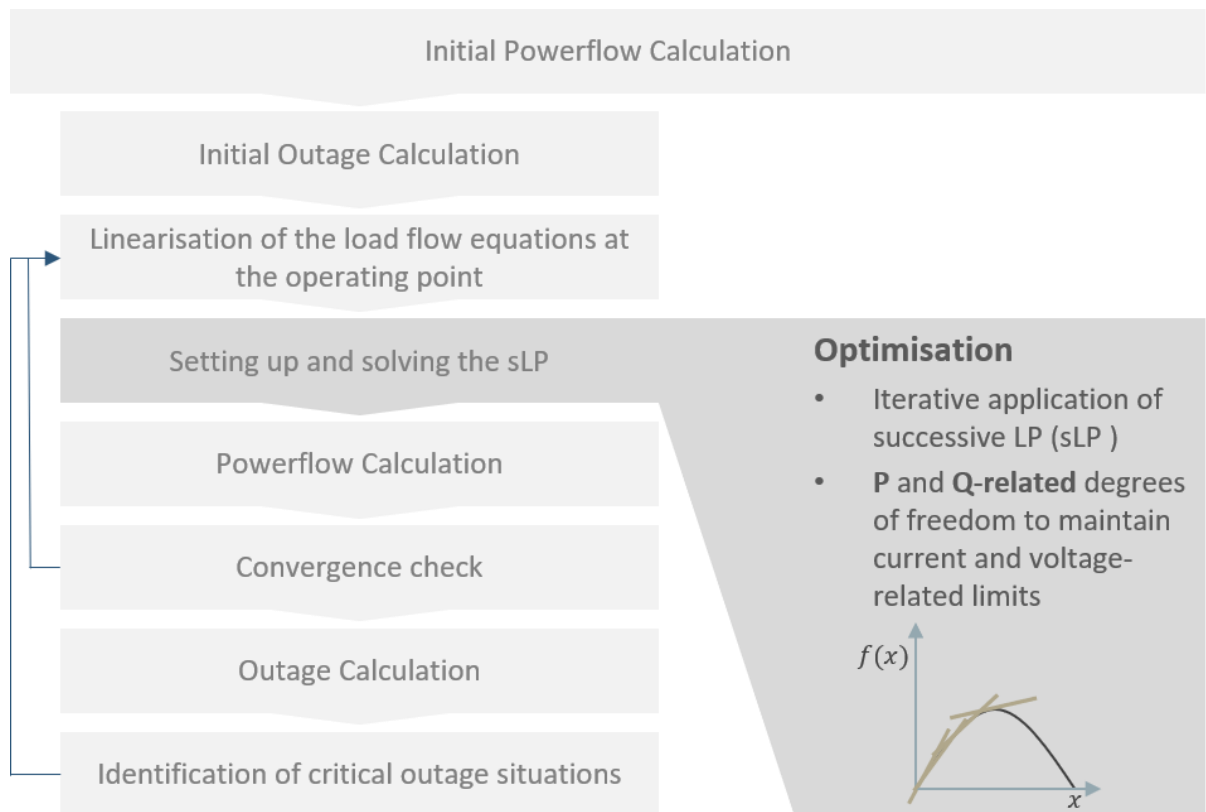


FIGURE 29: GRID OPERATION SIMULATION WITH ACTIVE AND REACTIVE POWER RELATED DEGREES OF FREEDOM

Table 7 summarises the KPIs that can be analysed in the context of the security assessment as part of the grid operation simulation.

TABLE 7: KEY PERFORMANCE INDICATORS DERIVED FROM THE GRID OPERATION SIMULATION

Key Performance Indicator	Unit	Short Description
Line Overloads ($n-0$, $n-1$)	[A]	Current-related overloads of the lines before grid operation measures
Voltage Band Violation ($n-0$, $n-1$)	[kV]	Voltage band violations on the busbars before grid operation measures
Redispatch Volume	[MWh]	Required volume of power plant adjustments as part of grid operation to remedy overloads
Redispatch Costs	[€]	Resulting costs of power plant adjustments as part of grid operation to remedy overloads
RES Curtailment	[MWh]	Necessary curtailment of renewable energy systems to remedy overloads
CO ₂ -Emissions	[t/MWh]	CO ₂ -Emissions from the energy supply after grid operation measures

Grid Stability

Dynamic grid calculations in the time domain are necessary to analyse different stability phenomena. With MatPAT [18] (MATLAB® based Power System Analysis Toolbox) a self-developed simulation

environment for RMS time domain simulations will be used to analyse the dynamic stability aspects in the context of Use Case 1.

Figure 30 represents the general workflow of the MatPAT tool. The basis for the stability assessment of an electric power system is the steady-state grid model with its different components (e.g. lines, loads, synchronous generators, photovoltaic and wind power plants, compensation devices, HVDCs, etc.). MatPAT uses the data format of the established open-source tool MATPOWER [19]. The initial operating points of the various components are then determined after importing the grid model using a power flow calculation. The steady-state grid data is extended by standardised dynamic component models as well as the associated parameters for the component models and their corresponding controllers (e.g. governors and voltage controllers). The existing model basis enables the analysis of the dynamic behaviour of the relevant generation technologies and loads. This includes models for HVDC transmission lines as well as converter interfaced generation units. Note, that the focus here is on analysing the systemic influence of HVDC systems on the AC grid stability and not on the detailed modelling of control concepts.

The dynamic behaviour of the different models is determined by differential-algebraic equations. These describe the time-dependent changes of the mechanical and electrical quantities in the associated grid components, whereas the algebraic constraints reflect the relationship between the currents in a linear grid according to Kirchhoff's laws. By solving the defined system of equations at each time step, all existing states and variables can be read out and evaluated after fault occurrences. In addition, it is possible to examine eigenvalues of the system as part of a small signal stability analysis or during the RMS-simulations. Table 8 summarises the KPIs that can be analysed in the context of the security assessment as part of the grid stability analyses.

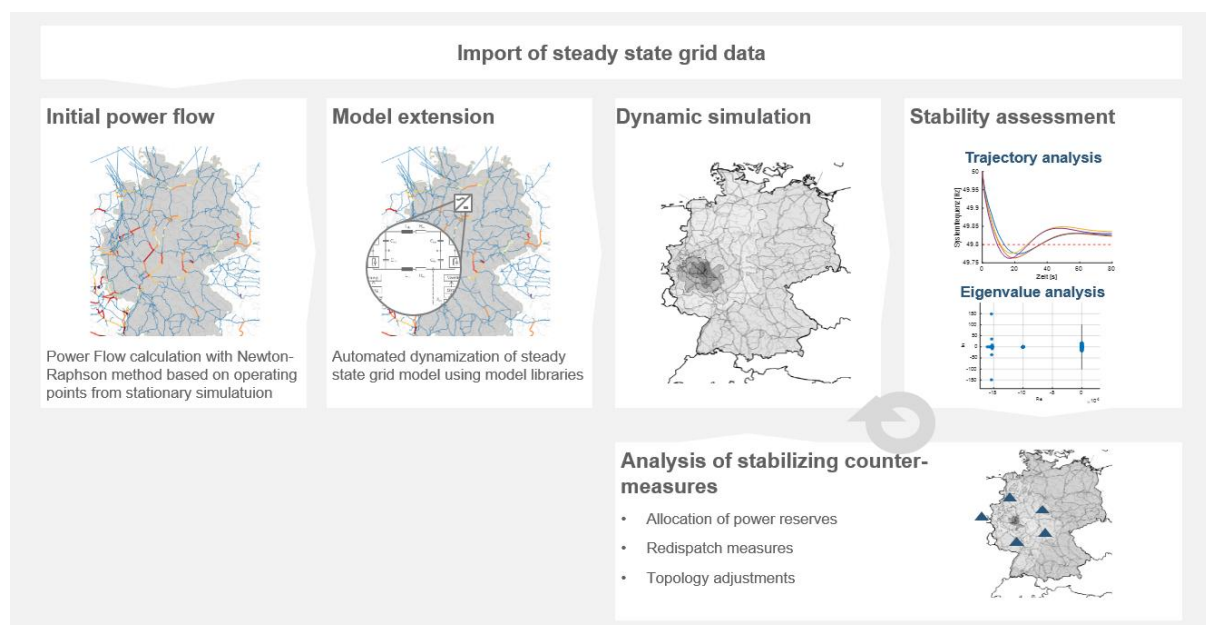


FIGURE 30: TIME DOMAIN SIMULATION FRAMEWORK

TABLE 8: KEY PERFORMANCE INDICATORS DERIVED FROM THE GRID STABILITY ANALYSES

Key Performance Indicator	Short Description
Rotor Angle Stability (Transient Stability)	Ability of the synchronous machines or generators connected in a power supply system to maintain synchronism after large disturbances (violation of the FRT capability curves, voltage angle differences, displacement of the rotor angles, tripping of machines)
Frequency Stability	Ability of the system to restore a stationary grid frequency, in particular, after significant disturbances causing an active power imbalance (Rate of Change of Frequency, Nadir/Zenith Frequency)
Voltage Stability	The bus voltages can be kept or returns to the specified limits throughout the entire system in normal operation or in case of feed-in and load changes or disturbances

4.1.4 Practical Assumptions

Design and evaluation of different HVDC overlay grid structures builds upon the basis of existing and already planned HVDC infrastructures, which within use case 1 will be considered as a scenario framework. This scenario framework includes existing offshore wind farm connections, interconnectors to other synchronous areas and parts of the existing and planned onshore systems. It especially includes HVDC systems that are designed as a monopole, equipped with LCC converters, have a nominal voltage of less than 525 kV, power ratings with less than 2 GW, are commissioned before 2030 or are in general not considered as multi-terminal capable. Within Use Case 1 those HVDC systems assigned to the scenario framework, depending on technology specifications and intended commissioning, will not be varied within the evaluation of different HVDC overlay topologies.

The enhancement of the initial framework shall be done via new HVDC systems or an expansion of already existing HVDC systems within the considered scenario time frame, that are in line with the HVDC framework described in D2.2 [13].

4.1.5 Operational Scenarios

In Use Case 1, a mid-2040s scenario will form the basis for each HVDC overlay grid topology evaluation. While the investigations for Use Case 1 focus on the continental European area, the most relevant AC grid areas to be considered are those adjacent to the continental European North Sea region up to the Alps.

4.1.6 Types of Disturbances

The contingencies considered for security and stability assessment within Use Case 1 will include AC and DC faults as described and defined in D2.2 [13].

AC-side contingencies include, among others:

- N-1 circuit contingency
- N-1 generator or converter outage
- N-1 Loss of a large load

Furthermore common-mode failure contingencies can also be considered as part of the security and stability assessment, including:

- N-2 Circuit Contingency
- Busbar fault, with loss of circuits connected to this busbar

As well as DC-side contingencies, including:

- Converter failure (single contingency/ “N-1”)
- Converter transformer failure (single contingency/ “N-1”)
- Bipolar converter trip / (“N-2”)
- DC P-E fault line (single contingency/ “N-1”)
- DC P-E fault busbar (single contingency/ “N-1”)
- DC P-P fault line (“N-2”)
- DC P-P fault busbar (“N-2”)
- DC-P-P-E fault line (“N-2”, (background: cable bundling for offshore)
- DC-P-P-E fault busbar (“N-2”)
- DC DMR fault line (single contingency/ “N-1”, not time critical)
- DC DMR fault busbar (“N-2”)

4.2 Use case 2

4.2.1 Use case workflow

This section describes the intended approach to be taken within use case 2, the GB system case study, following the R&R oriented methodology framework set out in Section 3.1. Figure 31 describes the general workflow that Use Case 2 will use to demonstrate the different aspects the methodology and compare different HVDC architecture options within WP6. A brief discussion of each section and the tools available or expected to be used for each is given below.

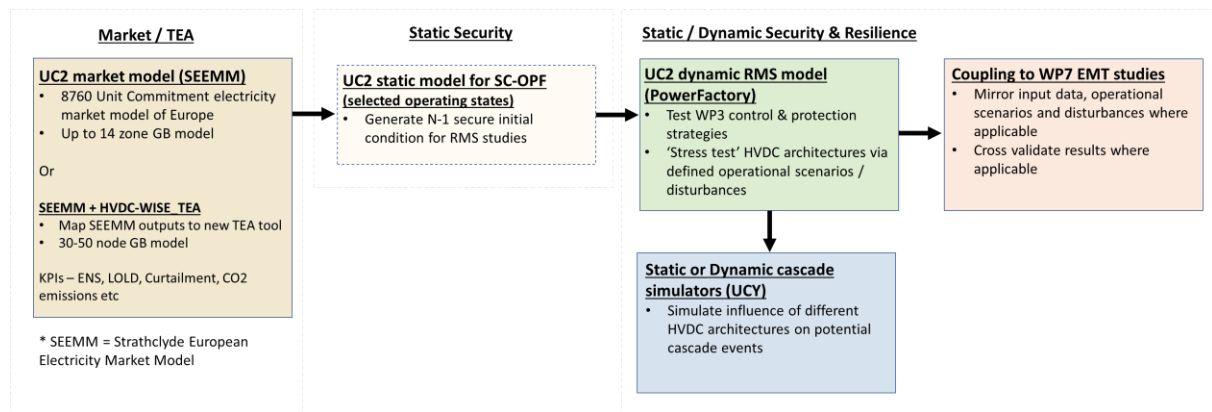


FIGURE 31: SUMMARY OF USE CASE 2 WORKFLOW.

4.2.2 Market / TEA analysis

For market and techno-economic assessment two approaches are available to the GB use case (Use case 2). Both make use of an existing market modelling tool – SEEMM (Strathclyde European Electricity market model) previously described in [20]. SEEMM is developed in the open-source Antares modelling platform and is capable of implementing a year-round 8760-hour unit commitment problem to discover the dispatch of generation plant and inter-area power flows between the different regions represented in the model subject to weather dependent inputs for demand and availability of renewable generation. The unit commitment optimisation determines a schedule of generation units that minimises the overall system operational cost of the system considering all proportional and non-proportional generation costs and external costs such as that of the unsupplied energy or spilled energy. It is constrained by the minimum and maximum production of each generation type, the maximum rate of change of production from each generator and the minimum amount of time for which it must be on if committed to run or run if it is not needed.

The model is capable of representing the operation of storage facilities such as pumped hydro and battery power. The model is solved in weekly blocks, which are coupled for the whole year with constraints respecting hydro-reservoir storage capacities. Transmission system flows are driven by price differences between the modelled nodes assuming a perfectly coupled market with within-week foresight. Renewable generation availability is modelled across Europe with reference to real historical outputs which respect temporal and spatial correlations.

Figure 32 shows the existing market model formulation of SEEMM where in general each European country is represented by a single node (with the exception of the UK and Denmark, recognising the existence of separate islanded regions) with modelling of an appropriate generation mix separated by plant type while constraints are imposed on the maximum net transfer capacity (NTC) of electricity trades that can take place between connected countries. Recent additions to the model have included development of a 14-zone disaggregated representation of the GB electricity system giving representation to the main thermal constraint boundaries within the system.

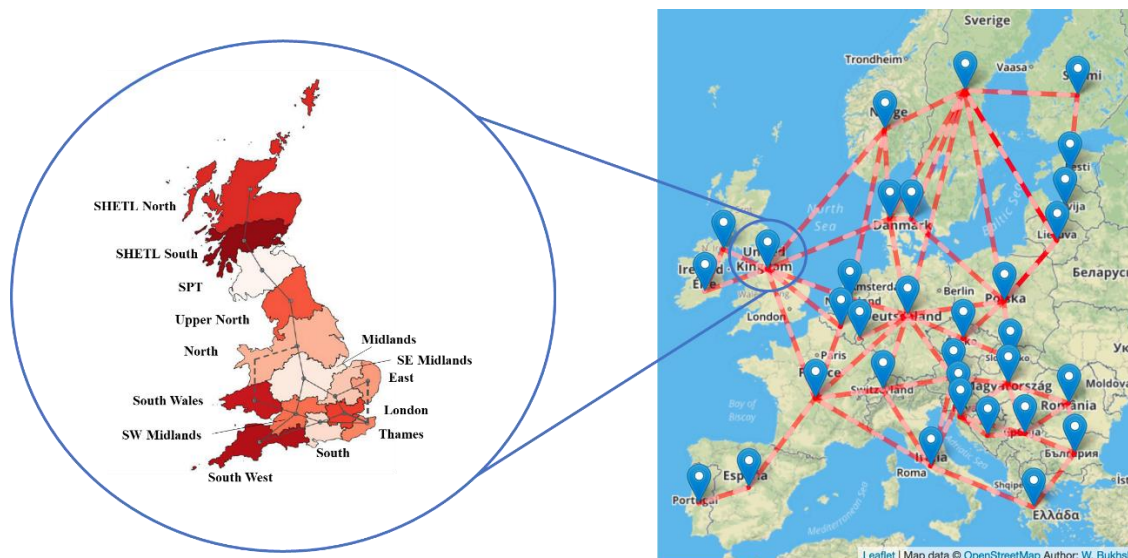


FIGURE 32: SEEMM REPRESENTATION OF EUROPEAN ZONAL MARKET AND DISAGGREGATED GB SYSTEM

It is possible to use the SEEMM platform to carry out a TEA assessment of potential different offshore HVDC architectures. This would be achieved via the creation of a node and branch transport model of different offshore grid architectures connecting offshore wind assets with the GB system and potentially the European system, distinguished by varying NTCs and transfer availabilities which could be sampled as a model input. The year-round market simulation would then generate KPIs such as energy not served (ENS), loss of load duration (LOLD), level of curtailment and carbon emissions that could be compared with a capital cost estimation of the various architectures.

Should project resources permit the possibility of developing a more granular model of the GB system implemented in MATPOWER would allow for the linking of outputs from the SEEMM market model to the HVDC-WISE_TEA tool described in Section 3.2.1. In such a case, the market model would provide the time-series inputs required for the tool, mapped to the more granular model of the GB system, allowing for a TEA analysis to be conducted with a higher level of consideration of thermal constraints and a more explicit consideration of the HVDC architectures being examined.

4.2.3 Static Security

Use case 2 leaders do not have access to an existing security-constrained optimal power flow (SC-OPF) tool capable of handling multi-terminal HVDC networks and so would look to the potential development of such a tool by project partners as outlined in Section 3.2.2, to facilitate this part of the methodology framework. Use case 2 would not seek to run a SC-OPF on all 8760 hours of a year and so unlike Use Case 1 is not focused on determination of particular KPIs related to static security. Instead, the main function of the SC-OPF would be pass N-1 statically secure initialised states onto the dynamic model of the GB system for a selected number of operating states of interest, taken from the market / TEA analysis or otherwise. The operating states of interest would seek to incorporate a range of potentially stressing conditions for the system including combinations of periods with high or low renewable generation and high or low system demand and may be selected via clustering methods or other means.

4.2.4 Static / Dynamic Security & Resilience

Use Case 2 will predominantly focus on dynamic security and resilience studies through the development of a representative RMS model of the GB system, developed in PowerFactory. The RMS model will build upon existing work that has developed reduced order representative models of the GB system. Recent development of a detailed 24-node representation with a high level of detail in the Northern half of the projected GB system for the early 2030's but a lumped representation of the remainder of the system will be augmented with a new representation of the Southern half of the network to create a representative model of the full GB system. Two main options are being considered for the level of detail being modelled in the southern half of the country with the end result likely to be a reduced order onshore system model in the range of 30-50 nodes that will then be augmented with the different offshore HVDC network architectures being considered in the project.

Two main focus areas for use of the Power Factory model are:

- Dynamic security assessment to test the performance of different control and protection strategies developed in work package 3 applicable to RMS studies.
- Dynamic resilience assessment - 'stress test' of system behaviour and performance of different HVDC architectures, control or protection strategies under a set of pre-defined operational scenarios and disturbances (potentially beyond N-1).

In the first instance, the development of the medium sized, highly decarbonised system GB use case presents an ideal opportunity to advance the testing of some of the control and protection strategies being developed in WP3 of the project from small-scale test case networks to a realistic example future system. Studies applicable to RMS simulation may be examined, for example control functions like supervisory control of MT-HVDC systems and the determination of set-points on the DC system pre- and post-disturbance or examination of different DC-side protection philosophies on AC system stability aspects.

Secondly, the aim would be to 'stress test' the performance of the system and different HVDC architectures against particular scenarios of interest. This would be done through analysis of a combination of sample operational scenarios and sample disturbance events, potentially going beyond the traditional N-1 or N-D security analysis. This will entail selecting low probability but feasible disturbance scenarios (outside of weather induced events that will be explored in the cascade simulator tool) affecting both AC and DC system components. Examples of initial thinking on scenarios of interest are outlined in Sections 4.2.6 and 4.2.7.

Coupling to cascade simulator tool:

While some resilience studies may be studied in Power Factory alone a key aim for the project is to further explore the dynamic resilience of different HVDC architectures by coupling the Use Case 2 Power Factory model with the dynamic cascade simulator tool that is outlined in Section 3.2.3. This will allow for the examination of the resilience of the different hybrid AC-DC configurations of the system to in particular extreme weather events, but also perhaps other selected trigger events and to explore potential system split scenarios and the ability of the different HVDC architectures to maintain or improve system resilience. A number of KPIs that can be used to compare performance of different system architectures with the tool are set out in Table 5.

The development of a MATPOWER version of the UC2 model would also allow for use of static version of the cascade simulator for comparative purposes.

Coupling to the restoration tool:

As mentioned in section 3.2.4, in use case 2 the restoration tool will be used to assess the impact of different AC/DC architectures on the restoration phase and its performance (mainly the calculation of ENS). The Power Factory model from the cascading simulator tool can be applied to extract the required inputs such as the static network/power system model, extended by some additional parameters/data related to the restoration procedure (time delays, required cranking power, etc.). The starting point of the restoration (i.e. which lines are available, what is the operating point of the system, ...) are also taken from the calculation performed by the cascading simulator tool. Combining the analysis of the restoration tool with the cascading simulator tool, the full resilience trapezoid is covered and analysed for the considered incidents.

Coupling to Work Package 7:

A smaller-scale 12 node representation of the GB system has been developed for intended use in the more computationally intensive EMT study environment. WP6 will work closely with WP7 to ensure that scenario input data is mirrored and mapped appropriately between the two model versions and also to provide input from RMS simulations on what scenarios would benefit from further analysis in the EMT domain.

The intention is also to develop a version of the smaller scale GB model in Power Factory. This will have two clear benefits, firstly to allow for cross-comparison and validation of model outputs in both platforms. Secondly, the smaller-scale version of the GB network may be the most appropriate representation to feed into Use Case 3 of WP6 which will include a reduced scale version of the European mainland network and a focus on the coupling of two AC systems via different HVDC architectures.

4.2.5 Practical assumptions

Deliverable 2.2 highlighted the common desire to develop use cases representative of a mid 2040's scenario, a timeframe that would allow for exploration of large-scale MT-HVDC networks connecting across Europe. The GB case study also outlined plans to develop an interim stage model of the early 2030's by which time significant development of offshore HVDC transmission links are already expected. A mix of national data (from the GB system operator, government or other authoritative bodies like the Climate Change Committee) and European level data (from ENTSO-E) will be used to generate the appropriate generation, network and demand backgrounds required for application in the use case 2 models.

As outlined in the previous section, the various different stages of modelling envisaged in the methodology require development of representative GB system models at different levels of granularity and on different platforms. Lower granularity models are required or most appropriate for both the early stage market analysis to be done in the SEEMM platform, for use in use case 3 in Power Factory, and for the EMT studies to be undertaken in WP7 in RTDS or PSCAD platforms. While Figure 32 outlined a 14-node zonal representation of the GB system currently available for market studies in SEEMM, it may be appropriate in UC2 to fully align the low granularity GB representations throughout the work in HVDC-WISE. Figure 33 gives a schematic overview of the model developed in WP7 for EMT studies that could form the basis of all the reduced granularity UC2 GB representations across all appropriate platforms. It represents the mainland system via 12 regional nodes with a representation of the key AC double circuit transmission links connecting each region as well as the HVDC links to the

islands of Shetland and Ireland. Further existing interconnections to mainland Europe are also shown and would be updated to match expectations for further developments out to the early 2030's and mid-2040's. Developing a version of this model across multiple platforms could be beneficial to the project for consistency of approach within the use case 2 implementation and also more widely for comparative purposes of various modelling approaches, perhaps including RMS, EMT and dynamic phasor platforms.

A higher granularity model of the GB system is preferred for use in the HVDC_TEA analysis platform, if used, as well as for static and RMS analysis in either of MATPOWER or Power Factory. As mentioned, the use case will build upon a 24-node Power Factory model and extend to create a full representation of the GB onshore system shown in Figure 34. Two main options are being considered for the level of detail to be used for the representation of the southern half of the country. The first would be to align with the reduced granularity model and simply append the Southern half of the 12-node GB representation of the GB system depicted in Figure 33. This would bring some benefits in mapping of scenario data between different platforms in WP6 and partial alignment with the EMT model in WP7 while still retaining a detailed representation in the Northern half of the country that may be sufficient for use in TEA and cascade analysis. The second option is to append a more detailed representation of the Southern GB system building upon another previously developed but less up to date 38-node model of the GB system with ~20 nodes in the Southern half of the system. Thus, a 30-50 node representation of GB will ultimately be developed for use in static and RMS studies in UC2. Schematic representations of both the existing Power Factory models are given in Figure 34.

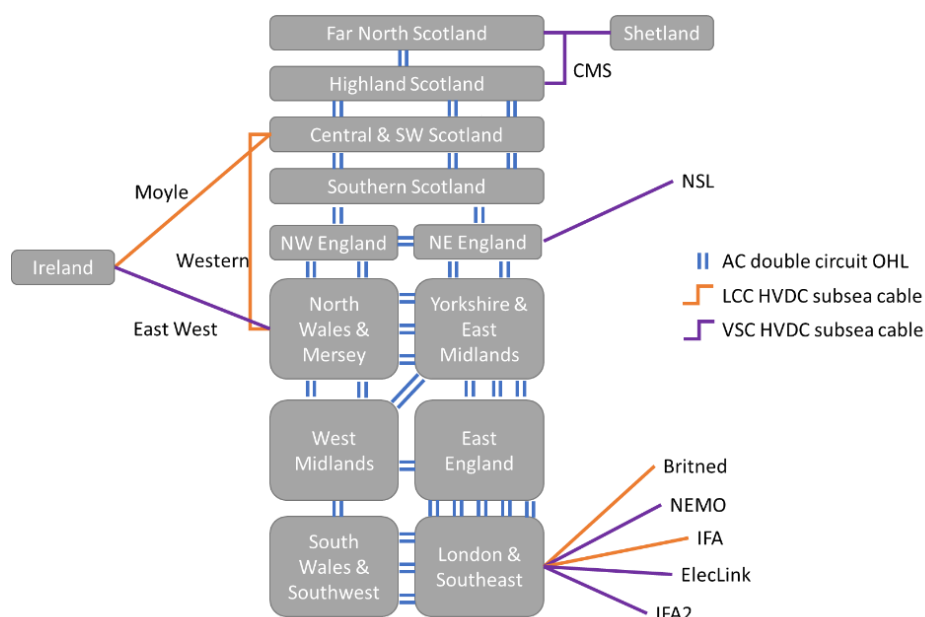


FIGURE 33: REDUCED GRANULARITY GB SYSTEM MODEL

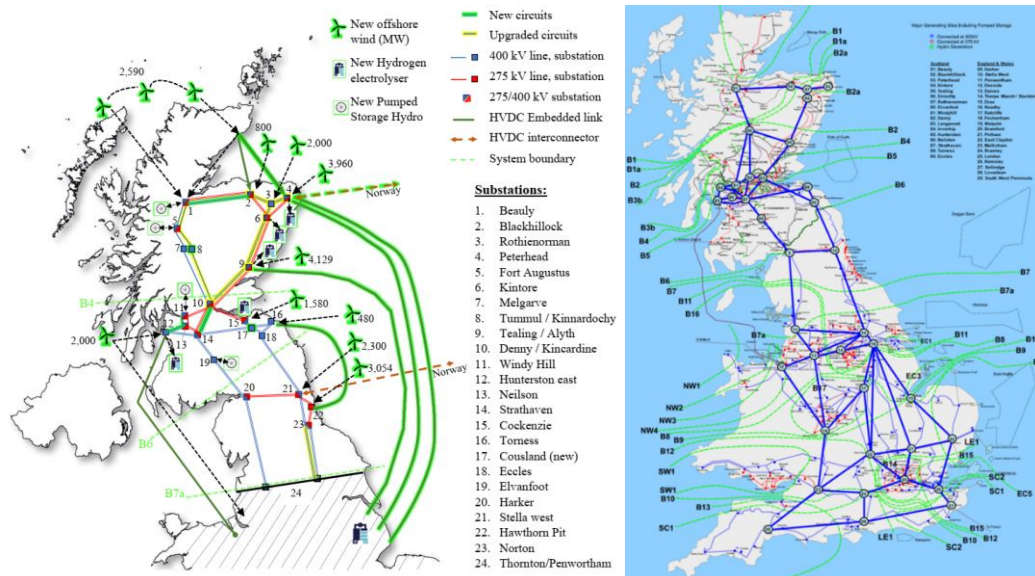


FIGURE 34: SCHEMATIC REPRESENTATIONS OF A) 24-NODE NORTHERN GB SYSTEM IN ~2032 AND B) 38-NODE WHOLE GB SYSTEM DATED TO ~2016/17

As outlined in D2.2 [13] UC2 will focus on modelling variations of the offshore HVDC based network that will be required to transport power from major renewable generation centres (often in northern and coastal regions) to the main demand centres in the south of the system. This will be approached in line with the main architectures set out in within the project while recognising the scale of offshore renewable generation potential and future system requirements. Figure 35 shows a high-level simplified overview of how different HVDC architectures may be appended to GB system for analysis within WP6 and WP7.

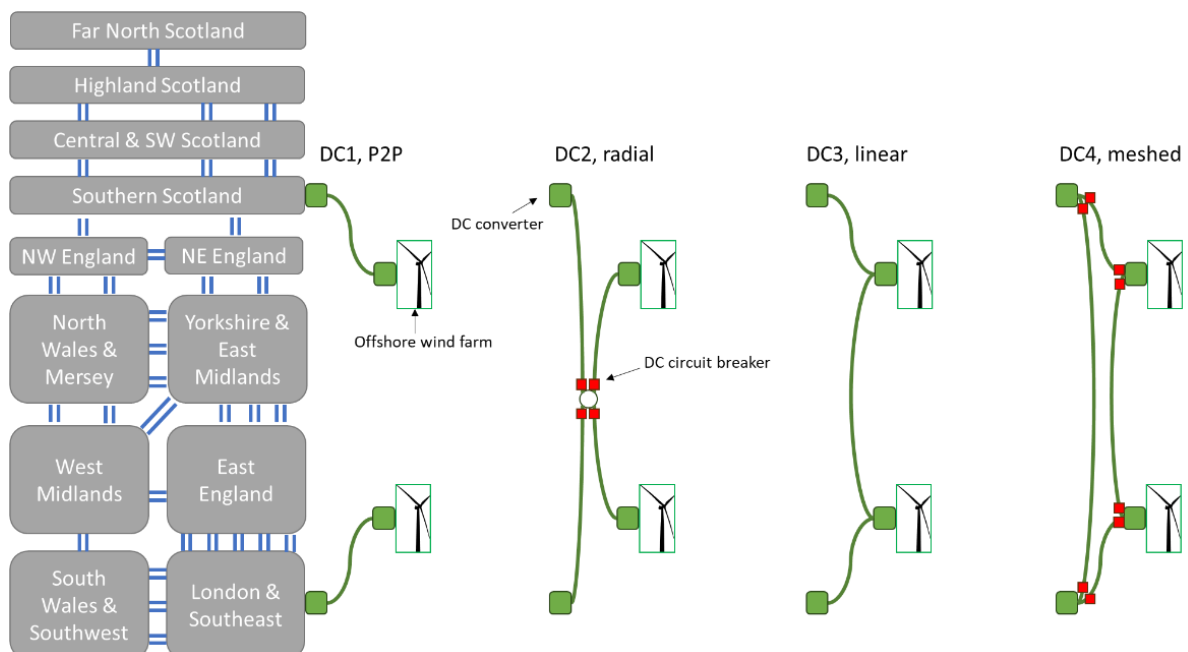


FIGURE 35: HIGH LEVEL REPRESENTATION OF HVDC-WISE ARCHITECTURES APPLIED TO LOW GRANULARITY GB SYSTEM MODEL

4.2.6 Operational Scenarios

Use case 2 will look to test security and resilience against a range of sample operational scenarios. While the market analysis will provide a whole year of hourly system conditions, a subset of conditions will be selected for deeper analysis via e.g. dynamic simulation in Power Factory. The set of chosen operational scenarios should test the ability of the hybrid AC-DC system to provide secure and resilient operation in the wide range of conditions that it might plausibly face. This is likely to include selection of periods with combinations of high and low demand, high and low renewable output, high and low penetration of inverter-based resources and high and low power transfers within the system. An example might be to test operation of the system under a disturbance when wind output is high, power transfers on the AC system are high and the system dominated, potentially wholly, by infeed's with power electronic interfaces.

4.2.7 Types of Disturbances

Deliverable 2.2 laid out a series of AC-side and DC-side contingencies that should be studied to examine operational security and resilience and these should at a minimum address what the GB security standards defined as events that should be secured against. Beyond testing system behaviour against securable events, particular 'stress test' cases relevant to the GB system will also be examined to test resilient to lower probability, higher impact events that might plausibly occur. This might include conditions that are likely to have the highest risk of system split, the outage of key busbars or double circuits transmission lines or the outage of HVDC substations.

4.3 Use case 3

4.3.1 Use case workflow

This section describes the intended workflow of Use Case 3. As all relevant tools to be used are already included in the previous use case definitions, the following paragraphs refer to those sections. Figure 36 provides an overview of the components considered in terms of the studies and the control and protection (C&P) functions demonstrated. It shows the complete methodology starting with a static market and TEA analysis, then the static resilience and reliability assessment to identify critical system conditions and disturbances, and finally the dynamic resilience and reliability assessment of the interesting load flow situations and disturbances. The topologies are defined and adapted to allow the demonstration of the relevant C&P functions and technologies of interest. More detailed information can be taken from the following subsections.

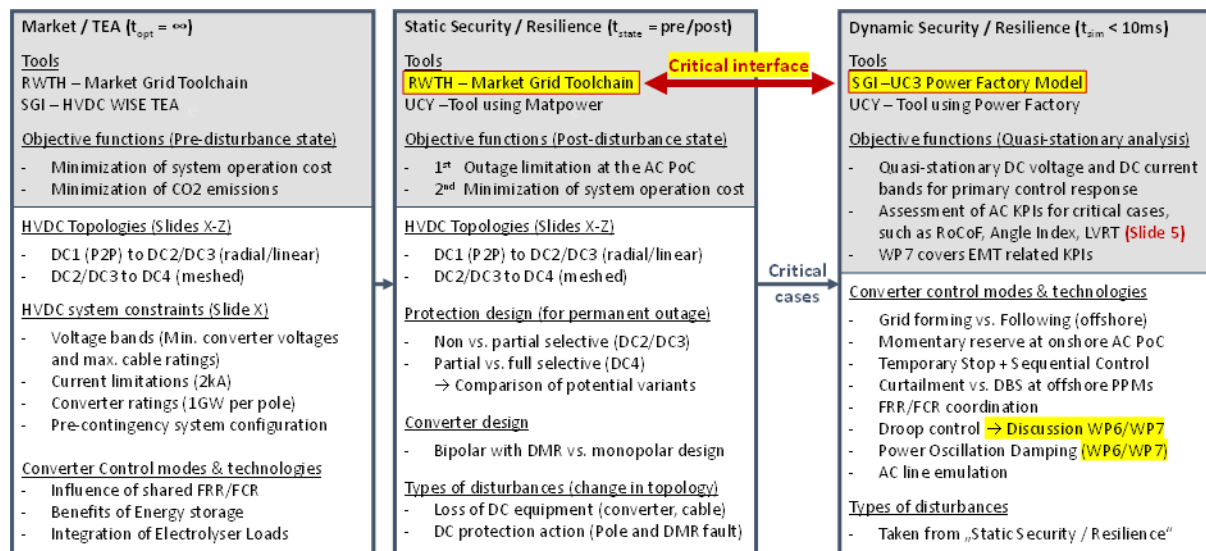


FIGURE 36: METHODOLOGY OF USE CASE 3.

4.3.2 Market / TEA analysis

The static analysis focuses on the undisturbed system state and starts with the market simulation (RWTH, Market Grid Toolchain) as described in Section 4.1.2, aiming at minimising the system operating costs and CO2 emissions. Hourly time series of dispatch for the given HVDC topologies are derived to identify critical system conditions that can be used for further analysis. The relevant boundary conditions within the HVDC networks are considered for the hourly time series (e.g. voltage and current bands, converter limitations), as well as the relevant criteria at the AC PoC. In addition, a technical-economic assessment (SGI, HVDC WISE TEA) of these topologies is performed. Different converter control modes and technologies can be addressed, such as the impact of a shared Primary Control Reserve (PCR) and Frequency Restoration Reserve (FRR) on the market and TEA assessment. The benefits of new technological developments such as battery storage or electrolyzers will also be addressed.

For the market and TEA analysis, the relevant KPIs can be summarized as follows. All these values are assessed for the undisturbed operating state, which can be used to ensure optimal operation of the HVDC networks.

- ENP – Energy not produced [MWh]
- ENS – Energy not served [MWh]
- CZE, CZC – Cross Zonal Exchange/Capacity [%]
- DMS – Demand Side Management
- Generation cost
- CO2 emissions

4.3.3 Static Security & Resilience

This is followed by the assessment of static safety (RWTH, Market Grid Toolchain) and resilience (UCY, Matpower). The HVDC topologies are studied by comparing the pre- and post-contingency system states, taking into account the relevant AC system requirements to limit the potential outage. This is particularly relevant for a closer look at the different protection designs, which the topologies are defined in [2] in such a way that the benefits and implications of the evolution from non-selective

protection to partial and fully selective approaches can be analysed. Another aspect will focus on the implications of using a monopolar converter design compared to the reference bipolar with DMR design. This step will also identify the relevant critical cases for dynamic assessment. Potential disturbances could be the loss of DC equipment (e.g. converters) or DC protection measures.

For static security & resilience, the relevant KPIs can be summarized as follows. All these values are assessed once for the undisturbed operating state and then after a fault has been cleared, including topological changes. This type of analysis is mostly focused on demonstrating the DC protection design to achieve a stable operating point afterwards.

- ENP – Energy not produced [MWh]
- ENS – Energy not served [MWh]
- CZE, CZC – Cross Zonal Exchange/Capacity [%]
- DMS – Demand Side Management
- Generation cost
- CO2 emissions

4.3.4 Dynamic Security & Resilience

In the third step, the relevant combinations of critical system states and disturbances will be assessed with a focus on dynamic security (SGI, Power Factory) and resilience (UCY, Power Factory). For this purpose, an interface will be developed in bilateral cooperation between RWTH and SGI to enable the use of market results to create Power Factory models for dynamic assessment within the HVDC WISE project. The main objectives are to evaluate the HVDC system performance (RMS time scale) and to identify the local effects at the AC PoC. Regarding the C&P functions, different converter control modes should be discussed as shown in the Figure 36. To reduce the number of simulations, the demonstration of the C&P functions will focus on the radial and meshed HVDC topologies. While the static security and resilience assessment focuses on the topological changes due to the different topologies, the dynamic security and resilience assessment focuses on the demonstration of the interesting converter control modes.

For the dynamic KPIs, a distinction is made between DC and AC related KPIs. The reason for this is that the R&R framework developed in HVDC WISE allows, for the first time, a detailed assessment of the DC side factors on the AC PoC. For all demonstrated C&P functions and topologies the following criteria have to be fulfilled. For WP6 the RMS time scale is considered, all EMT relevant aspects will be covered in WP7. The DC related KPIs, which focus on the quasi-stationary system dynamics, are used to enable a resilient system and proper protection design. They can be summarized as follows:

- Maximum and minimum DC voltages (Cable ratings, DC choppers, MMC discharge, required energy to provide FCR)
- Maximum DC current (consideration of converter and cable ratings, influence of DC protection design)
- DC voltage control in normal state and system split
- Voltage and active power restoration in sequential control

The AC related KPIs focus is on local impacts at the AC PoC. Indicators are chosen that give a clear indication of whether negative effects are to be expected from the different HVDC topologies. This also opens up the need for a certain level of detail in the AC network and interface activities to have

a good quality in the expected results. The main aspects here are to limit the potential outage and to ensure compliance with the grid code to reduce the impact on the stability of the AC system.

- RoCoF – Rate of Change of Frequency (Generation loss)
- AI – Angle index (Angle jumps, machine acceleration)
- LVRT – Low Voltage Ride Through (Converter control)
- VCPi – Voltage Collapse Proximity Index (Q imbalance)
- SCR – Short-circuit ratio (System robustness, equipment)

4.3.5 Practical assumptions

In Use Case 3, realistic practical assumptions should be considered as the reference case, depending on the different KPIs to be assessed. The following bullet points provide an overview of the relevant challenges and constraints to be considered when defining the use case. The following practical assumptions represent the reference case to be studied as a 'normal situation'.

HVDC System

- WP3 architectures merged with a fictional offshore HVDC development path
- Converter stations: Standard MMC Design, Bipolar + DMR configuration, ± 525 kV, $P_N = 2$ GW, Q_{AC} according to relevant AC requirements
- All converters on same or adjacent platform without geographical distance, 2 cable terminations per pole
- Grid following and voltage droop control of converters
- Cables: Underground sea cable, ± 525 kV, 2 kA, 2 GW
- Central earthing considering the DC protection design
- Location of FSD (non vs. partial vs. full selective design)
- Energy dissipation systems (pole arresters, DC chopper)
- Integration of large industrial loads (electrolysers)

AC System

- Detailed grid for DE, NL, BE, DKW, UK, partly FR (KPIs defined to assess the impact at the AC-PoC, as described in Section 4.3.4)
- Simplified representation of the remaining AC system using an appropriate reduction method (TBD)
- Offshore: P and N wind farms are decoupled (could be varied in post-contingency state)
- Onshore: P and N are connected to the same AC-PoC by default (could be varied for grid forming control)
- Ensure grid code compliance (e.g. NC HVDC, TAR 4131)

In addition, different converter control functions should be tested and evaluated, with a focus on the assessment of dynamic safety and resilience. The control functions listed below represent the variants that will be studied in comparison to the reference practical assumptions as stated above.

- Grid forming (VI, FFR, VSM): Act as a voltage source during the first instants of the event, provide inertial response (depending on the control strategy). Comparison between grid forming and grid following.
- Frequency control (FRR, FCR): Headroom of converters is allocated to provide this service. Containment of the frequency excursion.

- Temporary stop + Sequential Control
- Curtailment vs. DBS at offshore PPMs
- Voltage support using reactive power modulation (grid following): Reactive headroom of converters is allocated to provide this service. Damping of power oscillations that might trigger protection. Dynamic provision of reactive current to stabilize the voltage during faults (prevent FRT events).
- Droop control
- Power oscillation damping
- AC line emulation

With regard to the HVDC protection design, different strategies should be compared according to the three topologies described in Section 2.2.3. The focus is on the evolution from the reference P2P network to a radial/linear network to a fully meshed system. The main objective is to limit the permanent outage (static security and resilience) and the impact on primary protection and sequential control (dynamic security and resilience).

- Non-selective vs. partial selective protection for the comparison of the P2P reference topology with different linear and radial network structures.
- Full selective protection design is especially relevant for the fully meshed network topology.

Future developments are expected to include new types of loads in the hybrid AC/DC system. For this reason, different technologies should be evaluated in order to integrate them into the market and TEA toolset and to consider them in the static safety and resilience assessment.

- Integration of Electrolyser loads
- Benefits of Energy Storage

4.3.6 Operational Scenarios

The operational scenarios should be defined in such a way that the objectives can be demonstrated. The following operational scenarios could be helpful in achieving different objectives.

- Large offshore wind generation with strong import and/or export in the UK and continental Europe (Market optimization and testing of C&P functions, such as DC protection design, grid forming and shared system services)
- Very little offshore wind generation with focus on inter-area trade and shared system services
- Maximum parallel offshore infeed into the synchronous European grid (DC protection design for linear/radial and meshed network, testing of grid forming)
- Distributed offshore generation in the HVDC network (Share of system services in MT HVDC architecture (PCR/MR, grid-forming vs grid-following))
- ...

4.3.7 Types of Disturbances

Critical events (i.e. test scenarios) need to be defined under which the test methods should be applied, and indicators evaluated. HVDC architectures may introduce additional risks in case of DC faults and may threaten the stability of the AC system if the protection system is not properly designed (more specifically, the performance for certain test methods may be worse). The long-standing approach to N-1 or N-D (double circuit) contingency analysis may need to be revised. This will depend on the physical structure of the new HVDC infrastructure, with discussions already considering issues such as

the distance between the positive and negative cables of bipolar links. To improve understanding (and to map the application of test methods to the simulation models required to simulate the relevant test scenarios), the following disturbances on the HVDC side are considered:

Loss of power infeed or export (power imbalance)

Fault types

- Converter failure (single contingency, N-1)
- Converter transformer failure (single contingency, N-1)
- Bipolar converter trip (N-2)

Evaluation criteria

- Max. active power loss
- Active power recovery time (Quasi-stationary, Permanent)
- Reactive power recovery time
- DC voltage recovery time

Loss of transmission capacity (commutation on parallel lines causing overloads)

Fault types

- DC P-E fault line (single contingency, N-1)
- DC P-E fault busbar (single contingency, N-1)
- DC P-P fault busbar (N-2)
- DC-P-P-E fault busbar (N-2)
- DC DMR fault busbar (N-2)
- DC P-P fault line (N-2)
- DC-P-P-E fault line (N-2, background: cable bundling for offshore)
- DC DMR fault line (single contingency, N-1, not time critical)

Evaluation criteria

- Amount of lost transmission capacity (in GW)
- Transmission capacity recovery time (OHL ~ 100 ms, Cable → permanent + temporary depending on DC protection concept)
- Overload situations (converter and line overloads)

Loss of DC voltage control

- Loss of the only converter(s) controlling the DC voltage
- Loss of stability due to sudden impedance change

Loss of AC grid services (at multiple PoCs) – for example loss of grid forming units

- Loss of ancillary services: Q-control, Voltage support
- Loss of actual grid-forming: inertia provision, voltage control, fault current contribution, harmonic stability

5. Conclusion

In line with the objectives of the HVDC-WISE project, this document, Deliverable 6.1, introduces a practical methodology tailored to evaluate different reinforcing design options for HVDC-based grid architectures in real use cases. Indeed, this task facilitates the assessment and prioritization of different design options for HVDC architectures, which are identified to increase transmission network power transfer capability and enhance system reliability and resilience. To this end, the practical methodology involves defining key indicators, practical assumptions, operational scenarios, and types of disturbances tailored to each individual use case.

Section 1 of this document provided an introduction to the deliverable, including its scope and objectives, future use, and the structure of the document. Section 2 provided an overview of all individual use cases, which encompasses their corresponding network basis, the focus of relevant studies, and the identified AC/DC grid architectures.

Then, in Section 3, the document delved into representing the conceptual framework of the practical methodology, introducing each incorporated analysis along with the models and data necessary for each intended study required for each use case. Moreover, the toolset developed for the project, which performs adequacy, operational security, and resilience analyses, has been extensively described in this section. This description included the data and models needed for each study, and KPIs that can be calculated through them.

Following that, in Section 4, the document detailed the application of the methodology to each use case, including different studies and analyses, practical assumptions, operational scenarios, and types of disturbances required for each use case.

In essence, the efforts made in this task primarily focused on laying the groundwork for the R&R-oriented network expansion planning study of the use cases tailored for hybrid AC/DC transmission systems, related to other subsequent tasks in WP6. This is achieved through the assessment and prioritization of different identified design options for HVDC architectures corresponding to each use case, employing the developed R&R-oriented planning toolset and metrics related to the studies of interest.

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