Availability assessment of voltage source converter HVDC grids using optimal power flow-based remedial actions

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Abstract: This study proposes a methodology for assessing the availability of voltage source converter high-voltage direct current (HVDC) grids based on the enumeration methodology of contingency analysis with N−2 criteria and makes contributions in the computation of remedial actions and the definition and computation of reliability indices applied for HVDC grids. Thus, this study proposes the computation of remedial actions based on an optimal power flow, looking to maintain power exchanges between HVDC and high-voltage alternating current grids, when a contingency occurs on the HVDC grid and converter stations or HVDC lines are out of their operating limits. On the other hand, an HVDC grid has the function of injecting and extracting power from AC interconnected zones, and therefore, nodal reliability indices must be modified to indices that reflect the performance of the HVDC network to fulfill its function of interconnection of systems. This study defines two sets of availability indices applicable to HVDC grids: (i) loss of power and energy extracted from the DC grid to the AC zones and (ii) loss of power and energy injected to AC zones from the DC grid. The proposed methodology is applied to perform the availability assessment of the CIGRE B4 DC grid test system and the results are presented.

1 Introduction

High-voltage direct current (HVDC) grids or SuperGrids [1–4] based on voltage source converter (VSC) technology are one of the alternatives for developing power systems for the integration of non-conventional renewable energy (wind and photovoltaic); as well as one of the best strategies for the development of regional interconnection at continental levels. For these reasons, the planning of HVDC grids requires appropriate methodologies for the availability assessment of DC systems, considering the possible operation schemes of the conversion stations and, therefore, of the HVDC grid. However, currently, a grid availability assessment methodology for HVDC grids has not been developed in detail considering N−2 criteria, based on independent contingency events.

Some reliability analysis of HVDC systems focuses on the reliability assessment of VSC converter stations according to its architecture and converter topology, developing reliability models for modular multilevel converter (MMC) [5, 6] and cascaded two-level (CTL) [5] topologies. These models are used together the two-state stationary Markov process modelling of other components (DC line, AC breakers, transformers) for the assessment of single bipolar HVDC link based on frequency and duration methods [5], or based on probabilistic models of logical connection of components in series and parallel [7, 8]. In the same way, [6, 9] make a Markov state space model to assess the availability of a bipolar HVDC link with three converter stations, based on Monte Carlo simulations. These methodologies are useful for design purposes of HVDC and multi-terminal DC links, but not to assess the performance of the availability of a HVDC grid with a large number of HVDC lines and converter stations.

Some authors have proposed availability assessment of different HVDC configurations (radial, multiterminal, meshed) in order to assess the best interconnection alternative of renewable sources to an AC system [10]; following a Monte Carlo approach and measuring the undelivered energy due to wind farm disconnections. Other authors [11] have used the conventional AC availability assessment with the traditional reliability indices for including embedded HVDC links as another corridor in the AC system; however, no discussion is boarded around availability assessment of HVDC grids. These approaches do not apply to the evaluation of complex and meshed DC networks, because the multiple control actions on DC converter stations is not considered.

Authors of [12] studied the planning of transmission system including HVDC grids and assumes a reliability assessment with only single contingencies at the lines. Taking into account the length of HVDC lines and the availability of these components, an N−2 criterion must be applied to evaluate the performance of the grid. Hence, double independent contingencies of HVDC lines and/or converter stations in an HVDC grid system may cause major disruptions and also a negative economic impact. Thus, a reliability evaluation based on an N−2 criterion becomes essential and fundamental for the decision-making process during the electrical grid planning stage. This paper proposes a methodology for the availability assessment taking into account these criteria.

The availability assessment of a power system is generally used to evaluate the probability of supply power at a given load point adequately. The traditional nodal loss of load probability (LOLP) and the expected energy non-supplied (EENS) are used in previous works [10–12]. However, unlike AC systems, an HVDC grid has the function of injecting or extracting power from an AC interconnection zone, which implies that traditionally used nodal reliability indices must be modified to indices that reflect the performance of the HVDC network to fulfill its function of interconnection of systems. The availability assessment of an HVDC grid must evaluate its ability to supply power to AC zones that import energy, at the same time, it must evaluate the ability to transport the power from AC zones that export energy. In consequence, a new set of indices to measure these two functions must be proposed, as it is made in this study.

Consequently, this study develops a methodology to perform an availability assessment of VSC-HVDC transmission grids. Thus, the main contributions of this paper can summarised as follows:

• It proposes a novel methodology for assessing the availability of VSC-HVDC transmission grids based on the enumeration methodology of contingency analysis with N−2 criteria.
• It proposes the computation of remedial actions based on optimal power flow (OPF) when an N−1 and N−2 contingency occurs on the HVDC grid and converter stations or HVDC lines are out of their operating limits, looking to maintain power...
exchanges between HVDC and high-voltage alternating current (HVAC) grids. The remedial actions are computed when a DC system operating limits violation occurs, those include topology changes in the grid and adjustments in the power flow by means of an increase or decrease of power supplied by the converter stations, and taking into account power capacity of HVDC transmission lines.

- Unlike AC systems, an HVDC grid has the function of injecting or extracting power from an AC interconnection zone, which implies that traditionally used nodal reliability indices must be modified to indices that reflect the performance of the HVDC network to fulfil its function of interconnection of systems. It is for this reason that this study defines new reliability indices applicable to HVDC grids.

This study is organised as follows: Section 2 presents briefly the concept of the HVDC grid that interconnects several HVAC zones forming a hybrid HVDC-HVAC network. Then, Section 3 details the general algorithm of availability assessment based on the state enumeration method and defines availability indices that are proposed. This section, also, presents the operational objective to be satisfied by the HVDC grid in this hybrid system that is taken into account for the computation of remedial actions when contingencies at the HVDC Grid occur. Section 4 presents the methodology for computing remedial actions when single or double contingencies occur in the HVDC grid, which is based on an OPF computation. Section 5 presents the remedial actions obtained on the Cigre B4 DC test system for some particular single and double contingencies, evaluating some study cases and showing the effectiveness of the algorithm for computing the remedial actions. Section 6 presents the results of the availability assessment showing the computed value of the proposed indices. Finally, Section 7 presents the conclusions.

2 HVDC grid modelling for availability assessment

A hybrid HVDC-HVAC network is formed by one or more AC zones interconnected through DC elements, which act as a bridge. There are some VSC converters that inject power from AC areas to the HVDC Grid; while the other VSC converters extract power from the HVDC Grid to the AC areas, as shown in Fig. 1. These DC elements form the HVDC Grid and include VSC converter stations and HVDC lines.

The concepts of injection to and extraction from HVDC Grid are important for the definition of availability indices. On the other hand, each AC zone can have only one VSC converter to be interconnected to the HVDC Grid (as AC Zone 4 at Fig. 1) or many converters, as AC zones 1 to 3 in Fig. 1.

Fig. 2 shows a VSC bipolar converter representation [13]. As it is shown, each pole station includes the converter transformer, phase reactor, the AC/DC converter and DC capacitors. The group of these elements by pole will be called here the VSC station that will together represent a complex unit or component of the DC network.

A single contingency (called a $N-1$ case) in a VSC converter is the outage of only one pole of a bipolar station; in such case, the failed pole converter is out of service while the remaining half-station is still in service (i.e. the other pole). On the other hand, a VSC station double contingency (called an $N-2$ case) supposes an outage of the complete station (positive and negative poles). In the case of a monopolar converter station, when a fault in the VSC station occurs the converter station is put out of service.

In the same way, for bipolar HVDC lines a single contingency ($N-1$) is the outage of only one pole (positive or negative) while a double contingency ($N-2$) is the outage of both poles. In this case, the complex unit or component for reliability assessment purposes includes the line pole, DC protections, DC filters and all components required for its operation.

A particular component of the HVDC grid is the DC/DC station. In this study the component will be modelled using two DC/AC converters in a back to back configuration (Fig. 3), but with the difference of consider a very low impedance connection instead of an AC line. All DC/DC models implemented are considered as a unit in this study, $N-1$ contingencies in this equipment mean a total outage. It is important to mention; that the model can be different; however, it is not the purpose of this study to detail the modelling of this component of the HVDC grid, and further work must be developed.

2.1 Component two-state model (up and down)

The purpose of this paper is to assess the availability of an HVDC network, understood as the system or grid that connects several VSC stations through several HVDC lines. Generally, the AC system availability assessment models each component as a two-state model: up and down (Fig. 4) [5]. In the same way, for the
HVDC grid availability assessment each complex unit or component (a pole VSC station, a pole HVDC line) is modelled by the two-state model.

So, the main components of a pole (positive/negative) VSC-HVDC grid are: converter stations, a pole (positive/negative) HVDC line and DC/DC transformer [1] or DC hub. Each converter station in a HVDC grid plays the role of rectifier station or an inverter station.

Detailed models have been developed [5] in order to compute failure rates and mean time to repair (MTTR) associated from DC system to the AC system (as transformer, AC breakers). Guo et al. [5] shows the influence of the redundancy in the MMC or CTL redundancy in the unavailability of the converter. These detailed models must be used to compute the forced outage rate (FOR) of the converter station. For this study, data obtained by these methods gives the essential information required to the HVDC grid system availability assessment.

Some studies [2, 5, 14, 15] have computed or estimated failure rates and MTTR of the elements that compose a converter station; and give the guide for computing the equivalent failure rate (FOR) of the converter station. Based on these parameters the FOR of a converter station is calculated as follows [16]:

\[
\text{FOR}_{\text{Conv-Stat}} = \frac{\lambda_{\text{Sat}}}{\lambda_{\text{Stat}} + \mu_{\text{Stat}}} \tag{1}
\]

It is important to consider that the reliability of MMC station (\(R_{\text{MMC-Conv}}\)) depends on its sub-module (SM) connection architecture of IGBT components [6]; if this is a single-SM or multiple-SM IGBT type; and it depends on the converter topology (cold stand-by, warm stand-by, load sharing according to [6]). Thus, the unavailability of the component can be given as

\[
\text{FOR}_{\text{Conv-Stat}} = 1 - R_{\text{MMC-Conv}} \tag{2}
\]

where \(R_{\text{MMC-Conv}}\) is the availability VSC station computed with detailed models as those proposed by [5, 6].

The two-state model applies also for modelling each pole of a HVDC link. References [2, 10, 14, 15, 17] present data and models for the characterisation of the failure rate and MTTR for overhead HVDC line and for undersea/underground HVDC cable. The computation of failure rate of a HVDC pole and its MTTR must take into account failures along the line, DC protections, DC filters, and all component required for its operation. As [2, 10] state a failure of any of these components cause the outage of the transmission DC branch.

Therefore, the FOR of a transmission HVDC pole (\(\text{FOR}_{\text{HVDC-Line}}\)) is computed from the failure rate (\(\lambda_{\text{HVDC-Line}}\)) and the repair rate (\(\mu_{\text{HVDC-Line}}\)) as:

\[
\text{FOR}_{\text{HVDC-Line}} = \frac{\lambda_{\text{HVDC-Line}}}{\lambda_{\text{HVDC-Line}} + \mu_{\text{HVDC-Line}}} \tag{3}
\]

The DC transformer consists of a rectifier station and AC transformer and an inverter station whose purpose is to interconnect two DC networks of different voltage [1]. Other alternative for this task is the utilisation of DC/DC converter stations. However, these kind of equipments are under research and data for reliability assessment could be assumed equal to the converter stations.

2.2 Control modes of VSC converters

There are three possible control modes of VSC converters, namely: constant DC power, constant DC voltage (DC slack bus) and droop control [1, 13].

Constant power control is a droop-controlled converter with a constant control \(k_{\text{DC}}\) equal to infinity, thereby it does not change power if DC voltage changes.

DC slack bus is another special case of voltage droop control, where a converter assumes the deviations, while others do not take part in the regulation, like a slack AC bus, in this case, \(k_{\text{DC}}\) is equal to zero. This mode is used for example, in point to point VSC configurations.

With droop control, if a contingency occurs, the different stations will adjust the power injection, distributing the deficit in the remaining VSC converters with this control mode, according to their settings. Droop-controlled converters act like AC grids where some stations could take part of primary frequency controls or not. The droop settings do not have to be equal in all stations necessarily, which results in different power exchanges with AC grids. The expression for \(P-V\) droop relation is given by

\[
P_{\text{DC}} - P_{\text{DC},\text{a}} = \frac{1}{k_{\text{DC}}}(U_{\text{DC}} - U_{\text{DC},\text{a}}) \tag{4}
\]

\[
\Delta P_{\text{DC}} = \frac{1}{k_{\text{DC}}}\Delta U_{\text{DC}} \tag{5}
\]

where \(\Delta P_{\text{DC}}\) is the change in active power of VSC converter with droop controller, \(k_{\text{DC}}\) is the droop control constant and \(\Delta U_{\text{DC}}\) is the voltage change respect to normal operative conditions.

3 Availability assessment of VSC-HVDC grids

3.1 State enumeration

The proposed methodology uses the well-known approach of state enumeration which consists of count all possible system states. A system state is the combination of component states. The enumeration process starts with a state in which only one component fails. This state is called a first-order failure state. Then, as the probability of a high-order failure state, its settings. Droop-controlled converters act like AC grids where some stations could take part of primary frequency controls or not. The droop settings do not have to be equal in all stations necessarily, which results in different power exchanges with AC grids. The expression for \(P-V\) droop relation is given by

\[
P_{\text{DC}} - P_{\text{DC},\text{a}} = \frac{1}{k_{\text{DC}}}(U_{\text{DC}} - U_{\text{DC},\text{a}}) \tag{4}
\]

\[
\Delta P_{\text{DC}} = \frac{1}{k_{\text{DC}}}\Delta U_{\text{DC}} \tag{5}
\]

where \(\Delta P_{\text{DC}}\) is the change in active power of VSC converter with droop controller, \(k_{\text{DC}}\) is the droop control constant and \(\Delta U_{\text{DC}}\) is the voltage change respect to normal operative conditions.
A complex unit or component is a pole of a converter case that requires application of a remedial action.

The system state probability is calculated by (6), and the expected power. A variation of 5% respect to initial case is allowed, due that small variations in adjustments of injection and extraction in converters by the use of OPF algorithm are considered normal, but above this limit are included in indices calculation. In (5), a variation of \( \Delta U_{DC} \) would be proportional to a variation in \( \Delta P_{DC} \), if \( k_{DC} \) keeps constant. Inferior operational margin for voltage level of 0.95 p.u. is another reason to consider 5% as a margin for indices calculation. In [19], this percent in not taken into account, due to the fact that the solution method considers an algorithm different from OPF.

(iii) HVDC grid system OPF is evaluated for every contingency state. (iv) The reliability indices at each AC zone and DC grid given in Section 3.3 are evaluated.

3.3 Definition of availability indices

The requirements for assessing DC transmission system reliability are similar to those of AC transmission systems [16]; therefore, common reliability indices for AC transmission grids (such as LOLP, ENLPC, DNS and ENENS) are adapted for the availability assessment of HVDC grids.

The proposed reliability indices of VSC-HVDC transmission grids are classified in two sets: (i) loss of power and energy extracted from the DC grid to the AC grid or AC zones and (ii) loss of power and energy injected to AC zones from the DC grid. The new reliability indices of VSC-HVDC transmission grids are defined as follows:

3.3.1 Loss of power extraction probability (LOPEP): LOPEP is the probability that power extractions from the DC grid to AC zones reduce when a contingency occurs. LOPEP is calculated for each AC zone (see Fig. 1) as

\[
\text{LOPEP}_{ZA} = \sum_{i \in S} p_i \text{I}_{iZA} \tag{8}
\]

and the LOPEP for the DC grid is the probability of reduction from the total DC grid and is given by:

\[
\text{LOPEP}_{DC-grid} = \sum_{i \in S} p_i \text{I}_{iDC} \tag{9}
\]

where \( p_i \) is the probability of system state \( i \), \( S \) is the set of all system states associated with power extraction reductions and, \( I_{iZA} \) and \( I_{iDC} \) are given by

\[
I_{iZA} = \begin{cases} 
1 & \text{if } P_{i,extZA} - 0.95 P_{i,rangeZA} < 0 \\
0 & \text{if } P_{i,extZA} - 0.95 P_{i,rangeZA} \geq 0 
\end{cases} \tag{10}
\]

where \( P_{i,extZA} \) is the available power system extractions from the DC grid to the AC zone \( ZA \) when a contingency occurs and \( P_{i,rangeZA} \) is the total power extraction from the DC grid to the AC zone \( ZA \) under normal operating conditions. If \( I_{iZA} = 1 \) then state \( i \) belongs to set \( S \). Factor 0.95 was explained in Section 3.2. So

\[
I_{iDC} = \begin{cases} 
1 & \text{if } P_{i,extDC} - 0.95 P_{i,rangeDC} < 0 \\
0 & \text{if } P_{i,extDC} - 0.95 P_{i,rangeDC} \geq 0 
\end{cases} \tag{11}
\]

where \( P_{i,extDC} \) is the available power system extractions from the DC grid to the AC grid when a contingency occurs and \( P_{i,rangeDC} \) is the total power extraction from the DC grid to the AC zone \( ZA \) under normal operating conditions. If \( I_{iDC} = 1 \) then state \( i \) belongs to set \( S \).

3.3.2 Expected number of power extraction reduction (ENPER): ENPER is the number of times that power extractions from the DC grid to AC zones under normal operating conditions exceeds the power extractions when a contingency occurs. ENPER is calculated for AC zones and the DC grid. This is expressed (in occurrences per year) as
where \( f_i \) is the frequency of system state \( i \) and \( S \) is the set of all system states associated with power injection reductions.

### 3.3.3 Power extraction Non-supplied (DNS): The power extraction that was not transmitted from the DC grid to the AC zones. DNS is calculated for AC zones and DC grid. This is expressed (in MW) as

\[
\text{DNS}_{ZA} = \sum_{i \in S} p_i (P_{\text{in}jZA} - P_{\text{in}jZA}) I_{za} 
\]  

(14)

\[
\text{DNS}_{\text{DC-grid}} = \sum_{i \in S} p_i (P_{\text{in}jZA} - P_{\text{in}jZA}) |I_{dc}|
\]

(15)

### 3.3.4 Loss of power injection probability (LOPIP): LOPIP is the probability that power injection to the DC grid from each AC zone \( Z_A \) reduces when a contingency occurs. LOPIP is calculated for each AC zone. This is expressed as

\[
\text{LOPIP}_{ZA} = \sum_{i \in S} p_i I_{za}
\]

(16)

where \( p_i \) is the probability of system state \( i \), \( S \) is the set of all system states associated with power injection reductions and, \( I_{za} \), is given by

\[
I_{za} = \begin{cases} 
1 - P_{\text{in}jZA} - (0.95 P_{\text{in}jZA}) < 0 \\
0 > P_{\text{in}jZA} - (0.95 P_{\text{in}jZA}) \geq 0
\end{cases}
\]

(17)

where \( P_{\text{in}jZA} \) is the available power system injections to the DC grid from the AC zone \( Z_A \) when a contingency occurs and \( P_{\text{in}jZA} \) is the total power injection to the DC grid from \( Z_A \) under normal operating condition. If \( I_{za} = 1 \) then state \( i \) belongs to set \( S \).

The availability of the DC grid is measured by its capacity to supply the power to the different AC zones connected (LOPEPDC). However, LOPIP measures also the unavailability of the DC grid to receive power from a specific AC zone. Then, LOPIP must be local and non-global.

### 3.3.5 Expected number of power injection reduction (ENPIR): ENPIR is the number of times that power injections to the DC grid from the AC zone under normal operating conditions exceeds the power injections when a contingency occurs. ENPIR is calculated for each AC zone. This is expressed (in occurrences per year) as

\[
\text{ENPIR}_{ZA} = \sum_{i \in S} f_i I_{za}
\]

(18)

where \( f_i \) is the frequency of system state \( i \) and \( S \) is the set of all system states associated with power injection reductions.

### 3.3.6 Power injection non-supplied (INS): Ins is the power injection that was not transmitted to the DC grid from the AC zone. INS is calculated for each AC zone. This is expressed (in MW) as

\[
\text{INS}_{ZA} = \sum_{i \in S} p_i (P_{\text{in}jZA} - P_{\text{in}jZA}) |I_{za}|
\]

(19)

### 3.3.7 Expected energy non-supplied (EENS\(_{DC}\)): EENS\(_{DC}\) is the expected annual power that was not transmitted from the DC grid to the AC zone. EENS\(_{DC}\) is calculated for power extractions and power injections. This is express (in GWh/yr) as

\[
\text{EENS}_{\text{DC}-ZA_{\text{in}}} = \text{DNS}_{ZA} \times T
\]

(20)

\[
\text{EENS}_{\text{DC}-\text{grid}} = \text{DNS}_{\text{DC-grid}} \times T
\]

(21)

\[
\text{EENS}_{\text{DC}-ZA_{\text{out}}} = \text{INS}_{ZA} \times T
\]

(22)

where \( T \) is the time length (8760 h/yr).

### 3.3.8 Energy index of reliability (EIR\(_{DC}\)): EIR\(_{DC}\) is the ratio between the energy that will be extracted from the DC grid to the AC zones and the total energy extracted required by the DC system. This is expressed (in %) as

\[
\text{EIR}_{\text{DC-grid}} = 1 - \frac{\text{EENS}_{\text{DC-grid}}}{\text{EI}}
\]

(23)

where EI is the total power extraction for a period of time \( T \) in normal operational conditions.

### 4.0 OPF-based remedial actions

#### 4.1 Purpose of remedial actions

In a similar way to AC grids, contingencies in DC systems can occur in components like converter stations and DC lines [1]. In this case, power flow and bus voltages will change, and those new operational conditions could cause loadouts in HVDC lines and converters or changes in DC voltages that could be out of limits [1]. Remedial actions must define the set points of VSC converters to solve these non-acceptable operating conditions.

In this context, a methodology to execute an OPF is proposed, aiming to minimise the difference in injection and extraction between pre and post-contingencies, maintaining as much as possible power exchange between HVAC zones and HVDC grid. This will be done, adjusting the injection or extraction of each converter, subject to the capacity of HVDC and HVAC lines, VSC stations availability and capacity, and DC and AC bus voltages, among others.

At first instance, remedial actions are needed to guarantee system operation, but in this case, changes in injections and extractions of VSC converters are executed by an OPF with an objective function of reduce \( \Delta \text{P}_{\text{DC/AC}} \) adjusting power injection or extraction of VSC converters, given their respective operational restrictions. In other cases, AC contingences could lead to converter outages and their respective impact in the DC system. That is because only DC contingencies are evaluated, but also AC contingencies with their respective restrictions. The proposed methodology does not intend to execute an optimal dispatch for contingency conditions or a power loss reduction using OPF, as realised in [20–23].

#### 4.2 Model of zones for power exchange between DC and AC

In normal conditions, there is a balance between injection and extraction to/from the HVDC grid. This could mean, for instance, commercial transactions between regions, countries or even continents, which in many cases will be necessary to maintain, in order to not affect loads. When a contingency occurs, power injection or extraction contracted could not be delivered, and it is necessary to find an alternative to maintain previous power exchanges. Depending of the topology of HVDC grid and loadability of elements, when a contingency occurs is not always possible to redirect power injection or extraction in order to maintain the power exchange of initial case. Using the OPF algorithm proposed will allows to reach a new operational condition that respect operational margins and reduce the difference in power exchange between DC and AC zones.

In Fig. 1, a contingency in the converter station could be compensated changing extraction in the remaining stations of AC Zone 3, in this example; extraction in remaining converters could be incremented in a proportional way or choose a particular station in this zone to adjust extraction. In a general way, power could be redirected as:
\[ P_{e_i} = P_{e_i} + \frac{P_{c_{out}}}{n} \]  

(24)

where \( P_{e_i} \) is the new power extraction of converter \( i \), \( P_{e_i} \) is the initial power extraction of converter \( i \), \( P_{c_{out}} \) is the power extraction of converter in contingency, and \( n \) is the remaining extraction stations in the AC zone. This can be applied in the same way when a contingency in injection converters occurs, maintaining balance in power injected as much as possible.

The described method is analytical, but in larger systems with different topologies and configurations would be difficult to apply, being necessary to consider overloads of lines and converters, and voltage levels in the new operational condition. Because of that, it is desired that the adjustment in power injection and extraction be done by the OPF, considering system restrictions.

4.3 Objective function and restrictions

An OPF problem is represented in the following form:

\[
\begin{align*}
\text{min } & F(\lambda) \\
\text{subject to } & g(\lambda) = 0 \\
& h_{\text{lin}} \leq h_{\lambda} \leq h_{\text{max}}
\end{align*}
\]

(25)

The proposed algorithm adjusts the power injected or extracted by each VSC in the HVDC grid during contingencies, in order to reduce the difference between injections or extractions respect to initial case. So, the optimisation function is defined as

\[ \min \ \Delta P_{\text{DC/AC}} \]

(26)

where \( \Delta P_{\text{DC/AC}} \) is the difference between the injection and extraction of power for each AC zone in a contingency compared to the base case. Each zone is formed by one or more converters, and their respective power exchange \( Ex \) is calculated as the sum between power injection (negative) and extraction (positive) of each converter in the respective zone as

\[ Ex = \sum \text{Inj}_{ij} + \sum \text{Ext}_{ij} \]

(27)

where \( \text{Inj}_{ij} \) is the sum of power injection of converters in zone \( i \), and \( \text{Ext}_{ij} \) is the sum of power extraction of converters in zone \( i \).

\[ \Delta P_{\text{DC/AC}} = Ex_b - Ex_{c} \]

(28)

Reduction losses or economic dispatch during the contingencies are not considered in this methodology, the objective is to reduce power exchanges between AC zones and HVDC system when the different \( N-1 \) and \( N-2 \) failures occur.

4.4 Restrictions

The following basic operational restrictions are considered for the elements in DC and AC grid

\[
\begin{align*}
V_{dc\text{min}} & \leq V_{dc} \leq V_{dc\text{max}} \\
V_{ac\text{min}} & \leq V_{ac} \leq V_{ac\text{max}} \\
P_{c_{in}} & \leq P_{c_{in}} \leq P_{c_{out}} \\
P_{ac_{i}} & \leq P_{ac_{i}} \leq P_{ac_{i}} \leq P_{ac_{i}} \\
P_{c_{g}} & \leq P_{c_{g}} \leq P_{c_{g}} \leq P_{c_{g}} \\
(P_{dc_{i}}, P_{ac_{i}}, P_{c_{g}}, P_{c_{g}}) & \leq (V_{ac\text{min}}, V_{ac\text{min}}) \rightarrow (1.05) \text{ p.u.}
\end{align*}
\]

where \( V_{dc_{i}} \) and \( V_{ac_{i}} \) is the voltage magnitude of DC and AC node \( i \) with operational limits from 0.95 p.u. \((V_{ac\text{min}}, V_{ac\text{min}}) \rightarrow 1.05 \text{ p.u.}

\( P_{c_{i}} \) is the capacity of converter \( i \) \( P_{dc_{i}} \) and \( P_{ac_{i}} \) are the transmission capacity from bus \( i \) to \( j \) in DC positive and negative poles and AC lines, and \( P_{ac_{g}} \) is the AC generation available in the respective zone \( i \) to be injected in the HVDC grid, \( P_{dc_{i}} \) is the maximum power that converter stations can inject into the DC grid from AC zone \( i \), according to \( P_{dc_{ac_{i}}} \), and \( P_{gen} \) is the generator capacity.

Loadability limit for branches is assumed equal to its respective power injections and extractions are presented in the DC/DC converter, which is not desired. This restriction allows a change in the power flow for DC/DC converters during contingencies:

\[ P_{c_{imp}} = P_{c_{out}} \]

(30)

where \( P_{c_{imp}} \) is the power input in DC/DC converter and \( P_{c_{out}} \) its power output.

It is important to mention that the power flow through the DC/DC converter can be adjusted in order to alleviate important HVDC overloads; in these sense, the DC/DC converter constitutes a current flow controller or a power flow controller that gives flexibility to the operation of the DC system [24, 25], whose properties could be used to compute remedial actions. The impact on the availability assessment of these actions must be studied in further works.

5 Case study

The reliability evaluation methodology proposed in this study is used to calculate the reliability indices of the CIGRE B4 DC Grid Test System (Fig. 6).

5.1 Test system

The CIGRE B4 DC grid test system [26] consists of 22 converter stations, half of them connected to the positive pole and the remaining connected to the negative pole, 30 DC lines, 2 DC–DC converters, and eight AC lines. With voltage levels and AC zones as shown in Fig. 6. Table 1 shows the power generation capacity of each zone.

Bipolar VSC stations are identified with two numbers in Fig. 6, one for positive pole and the other number for the negative pole. For example, the bipolar VSC station identified as 8/81 connects node 201 of the AC Zone 1 to the HVDC Grid to the positive and negative pole of the grid, respectively.

With these components is possible to obtain a total of 1953 system contingencies: 62 contingencies with an outage of only one component (a single converter station or a single DC or AC line) and 1891 contingencies with an outage of two components, combining \( N-1 \) contingencies. The probability of each state is computed using (6). DC buses are identified by two numbers; for example, DC bus 8/81. The first number (8) refers to the positive pole; while the second number (81) refers to the negative pole. The power flow results of CIGRE B4 DC grid test system shown in Fig. 6 are calculated using MatACDC for base case. Main power flow results are summarised in Table 2 for initial case, showing power injections and extractions in each AC zone, and their respective \( \Delta P_{\text{DC/AC}} \).

The \( \Delta P_{\text{DC/AC}} \) of the base case, Table 2, is used to compute \( Ex_b \) to be used in (28). Also, as operational voltage limits are used 0.95 and 1.05 p.u. in both systems, AC and DC. The capacity of each VSC is 1000 MW by pole in DC Zone 1, 2000 MW by pole in DC Zone 2, and 3000 MW by pole in DC Zone 3 (see Fig. 6). These will be used as the constraints given at (29).

5.2 Reliability parameters of components

Table 3 shows reliability parameters for converter stations and DC lines of the CIGRE B4 DC grid test system based on data from [15] for DC lines and converters, and for AC lines based in [27], the
first study case will use them. In DC, for overhead lines and cables, the same values are assumed independent of the type of line.

A second study case will be developed assuming a reduced failure rate for converter stations $\lambda_{\text{Conv Stat}}$, as indicated in Table 4, in order to analyse how improvement in VSC technology will increase system reliability.

Camargo and Rios [15] compute the failure rate ($\lambda$) and the repair rate ($\mu$) of each component of a VSC-HVDC system from data obtained from [2, 5, 7, 14, 28–32]. In [15], the components were grouped as: AC and auxiliary equipment, IGBT converter station, protection and control equipment, DC and auxiliary equipment, and overhead transmission DC line; and Tables 3 and 4 gives the original data from the references and the rates computed.

### Table 1: Power generation capacity ($P_G$) by AC zones

| AC zone | Node | $P_G$, MW |
|---------|------|-----------|
| 1       | 200  | 2000      |
|         | 201  | 2000      |
| 2       | 207  | 1000      |
|         | 208  | 1000      |
|         | 209  | 1000      |
|         | 210  | 1000      |

### Table 2: Power injections and extractions by AC zones, base case

| AC zone | Type  | Injection, MW | Extraction, MW | $\Delta P_{\text{DC-AC}}$, MW |
|---------|-------|---------------|---------------|-----------------|
| 1       | Inj/Ext | -1992.1       | 390.8         | -1603.3         |
| 2       | Inj/Ext | -156.2        | 3908.3        | 3752.1          |
| 3       | Inj    | -1000.0       | 0             | -1000.0         |
| 4       | Inj    | -1000.0       | 0             | -1000.0         |
| 5       | Ext    | 0             | 100.0         | 100.0           |
| 6       | Inj    | -408.4        | 0             | -408.4          |

### Table 3: Parameters for availability assessment VSC-HVDC stations and transmission lines – Case 1

| Component           | $\mu$, rep./y | $\lambda$, out./y |
|---------------------|---------------|-------------------|
| converter station   | 75.60         | 1.76              |
| DC transmission line | 22.82         | $0.166 \times \frac{L}{100\text{km}}$ |
| AC transmission line | 876           | $0.390 \times \frac{L}{100\text{km}}$ |
Table 5 \( \Delta P_{\text{DC/AC}} \) for single contingency in VSC converters stations

| AC zone | Base case | 2   | 81  | 151 | 31  | 91  |
|---------|-----------|-----|-----|-----|-----|-----|
| ZA1     | -1603     | -0.6| -789| -369| -0.4| 0.2 |
| ZA2     | 3752      | -2.3| -708| -412| -0.7| -162|
| ZA3     | -1000     | -78.1| -0.1| -7.2| -0.4| -210|
| ZA4     | -1000     | -0.5| -0.1| -58.1| -0.4| 0   |
| ZA5     | 100       | 0   | 0   | 0   | 0   | 0   |
| ZA6     | -408      | 73  | 59.3| 3.9 | 0.2 | 37  |

5.3 Remedial actions for particular N−1 and N−2 contingencies

Several \( N - 1 \) and \( N - 2 \) contingencies are presented and analysed in order to show how the computed remedial actions changes power flows at converter stations (injections and/or extractions from DC grid).

The remedial action solution method is implemented through an interior point algorithm [33] using Matlab, using MatACDC for computing the power flow of the test system Cigre B4.

When a contingency occurs on the slack converter station of the HVDC network, the slack node is reassigned. This is taken into account for computing of \( \Delta P_{\text{DC/AC}} \).

Simulations have been made on a computer Intel Core i7 8th Gen, CPU@ 1.80 GHz (8 CPUs), ~2.0 GHz, RAM 8 GB. The computational time depends on the steptolerance used in algorithm. Steptolerance is a parameter of interior point algorithm in Matlab [33], which is related to the size of the last step evaluated, meaning the size of the change in location where objective function was evaluated, indicating to the algorithm when to stop iterating.

5.3.1 \( N - 1 \) contingencies: For the availability assessment all single contingencies at converter stations are simulated. In this section five cases are illustrated in order to show the impact of remedial actions on power injections to or extractions from the DC network. So, Table 5 shows the changes in power transfer between AC and DC networks (\( \Delta P_{\text{DC/AC}} \)) for the following single contingencies (i.e. one pole contingency)

Contingency in converter station 2 (connection of AC zone 3 and DC Zone 1): there is no possibility of adjustment in converter 1, due to the capacity limit of the HVDC line 1–2 and the capacity of the converter station. Then, a change in \( \Delta P_{\text{DC/AC}} \) is presented. However, power exchange at the extraction zones is maintained. Significant changes are presented in the injection of ZA3 and ZA6, but they have the possibility of adjusting the power generation. Without the application of remedial actions algorithm, the loss of injection in ZA3 would be 200 MW, but the remedial action reduces it to 78.1 MW.

Contingency in converter station 81 (connection of AC zone 1 and DC Zone 3): injection and extraction losses are presented in ZA1 and ZA2, ZA6 injection increment reduces \( \Delta P \) in ZA2. Without the application of remedial actions algorithm, the loss of injection in ZA1 would be 996 MW, but the remedial action reduces it to 789 MW.

Contingency in converter station 151 (connection of AC zone 2 and DC Zone 3): extraction loss is assumed by converters 15, 13/131 and 4/41 in ZA2. The application of remedial actions algorithm reduces the loss of extraction in ZA2 from 754 to 412 MW.

Contingency in converter station 31 (connection of AC zone 2 and DC Zone 2): injection loss is assumed by converter 3 in ZA2. In the same way, loss of extraction in Z2 would be 78.2 MW without remedial action, but this reduces it to 0.7 MW.

Contingency in converter station 91 (connection of AC zone 3 and DC Zone 3): loss of injection and extraction are presented in ZA2 and ZA3, increment of injection in zone 6 reduces \( \Delta P \) in ZA2. The remedial action algorithm reduces the loss injection in ZA2 from 300 to 162 MW.

The value \( \Delta P_{\text{DC/AC}} \) at Table 5 is presented as the difference in MW respect to the base case or non-contingency case. VSC outages can lead to an active power imbalance within the HVDC grid since the injected power into the HVDC grid cannot get exported from it. So, in dynamics direct overvoltages will be occurred and in statics, no feasible OPF solution can be sought. In this regard, the reduction of the power injected into the HVDC grid is inevitable.

Negative values in Table 5 mean reduction in \( \Delta P \) respect to the base case, in other words, a loss of injection or extraction that could not be adjusted by OPF, \( \Delta P_{\text{DC/AC}} \) is computed according to (28). In all cases, algorithm restrictions guarantee that new operational conditions respect loadability of elements and voltage level in DC and AC elements, reaching a stable operational condition.

5.3.2 \( N - 2 \) contingencies: For the availability assessment all double contingencies at converter stations are simulated. Table 6 shows the \( \Delta P_{\text{DC/AC}} \) for the following double independent contingencies:

Contingency in converter stations 1 and 19: loss of extraction in ZA1 is 389 MW, which reduces injection in this zone to 1603 MW. This impacts extraction in ZA2 and injection in ZA3 (2/21), but at the same time increment of injection in ZA3 (9/91) and ZA6 helps to reduce \( \Delta P \) in ZA2 to 279 MW.

Contingency in converter 8 and 81 (i.e. both poles of station 8): one of the largest contingencies, losing all injection from ZA1 (1992 MW). In order to reduce \( \Delta P \) in ZA1, the power extraction in this zone was stopped, allowing 9/91 in 3 to increase the
injection in order to compensate lack of injection in ZA1, but it is limited for capacity of DC lines 8–9, 9–10 and 10–11.

Contingency in converter stations 3 and 31: loss of injection in ZA2 is 156 MW, but at the same time, the power extraction is reduced to 3754 MW, with an $\Delta P$ in ZA2 reduced to only 6.5 MW. In this case, it is not possible to compensate injection from ZA2 in this case.

Contingency in converter stations 4 and 41: due to the configuration of the system, when a contingency in 4/41 occurs, 3/31 cannot inject power into DC network, turning into a loss of injection in ZA2, but in this particular case, 3/31 turns into an extraction station, which helps to reduce $\Delta P$. Without application of the remedial action algorithm, the power loss extraction in ZA2 would be 693 MW, reducing it to 132 MW.

Contingency in converter stations 8 and 9: large loss of injection respect to base case (1296 MW), in the current configuration it is possible to increment power injection in converters 81 y 91 in order to reduce $\Delta P$. Finally, loss of injection is reduced to 1108 MW, but it is limited for a possible overload in lines 81–91 if converter 91 increases its injection. This case is shown before and after OPF in Figs. 7 and 8, appreciating that not only $\Delta P$ is reduced, but also voltage levels in DC buses are improved to the acceptable operational window (0.95–1.05 p.u.).

Contingency in DC/DC converters 130/1310 & 70/710: contingency in the two DC/DC converters, which change completely the topology of the system. This affects the power extraction in ZA2, due that injection in ZA4 is reduced because of load level of lines, and particularly lines A1-2/C2. Without adjustments, operational limits would be violated.

### 6 Availability indices results

The availability indices proposed in Section 3.3 are calculated for the AC zones ZA1 to ZA6 and DC grid; these results represent the Case 1. The computation of these indices takes into account single contingencies at converter stations, single pole HVDC lines contingency, and their combinations (i.e. a converter station and a pole of the HVDC line). Table 7 shows the indices for AC zones which supply power to the power injection converters and Table 8 shows the indices for AC zones which power is supplied from the power extraction converters. Finally, Table 9 shows indices for the DC system.

Contingencies in DC converter stations are the main reason for DNS/EENS, in special converter stations with highest injection as 8/81, 9/91 and 10/101, and extraction converter stations as 13/131 and 15/151. However, DC lines contingencies in many cases impact in a significant way the EENS, particularly DC lines in point to point connections as 4/41–5/51 where all injection from zone 6 is lost. In DC zone 3, lines from 8/9 to 9/91, and from 9/91 to 12/121 present a major weakness in this system, due that a failure $N–1$ causes a loss of injection that is not possible to mitigate increasing injection in the remaining pole, although that stations and generation available could supply part of power lost, but line capacity cannot transport much more power in many cases.

As expected, the contribution of single contingencies to the availability indices is higher than double contingencies because of the probability and frequency of these states. Double contingencies ($N–2$) are more severe but their contribution to reliability indices is lower.

In the case of improved failure rates of VSC converter stations ($\lambda_{Conv - Stat}$) (case 2) of Table 4, an important improvement in the availability indices was obtained, as Tables 10–12 shown.

EENS$_{DC}$ was reduced 142 GWh/y, and EIR increased from 8.28 to 8.65% in 0.37%, which is a considerable value, due to the total number of contingencies analysed.

### 7 Conclusions

A novel methodology of availability assessment for VSC-HVDC transmission grids using the computation of remedial actions based on an OPF algorithm is proposed in this study, making the following contributions: (i) formulation of an availability assessment methodology based on state enumeration of bipolar VSC-HVDC grids that includes as basic components converter stations and DC; (ii) implementation of an OPF-based algorithm for computing remedial actions in order to reduce $\Delta P$ between DC and AC zones when contingencies occur, considering operational restrictions and margins (iii) proposition of a new set of reliability

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**Fig. 7** Power flow in CIGRE B4 DC grid test system after an outage of converters 8 and 9
Fig. 8  Power flow in CIGRE B4 DC grid test system after an outage of converters 8 and 9, and application of OPF

Table 7  Reliability indices – power injections to DC grid from AC zones – case 1

|     | LOPIP, % | ENPIR, occ./y | INS, MW | EENS\text{DC}, GWh/y |
|-----|----------|---------------|---------|----------------------|
| ZA1 | 8.19     | 13.78         | 38.72   | 339.19               |
| ZA2 | 6.80     | 10.70         | 2.71    | 23.78                |
| ZA3 | 11.26    | 17.43         | 24.18   | 211.84               |
| ZA4 | 10.15    | 13.53         | 25.33   | 221.96               |
| ZA6 | 7.05     | 11.16         | 10.04   | 87.95                |

Table 8  Reliability indices – power extractions from DC grid to AC zones – case 1

|     | LOPEP, % | ENPER, occ./y | DNS, MW | EENS\text{DC}, GWh/y |
|-----|----------|---------------|---------|----------------------|
| ZA1 | 7.06     | 11.19         | 13.67   | 119.82               |
| ZA2 | 15.71    | 24.20         | 61.85   | 541.84               |
| ZA5 | 0.27     | 0.04          | 0.02    | 0.18                 |

Table 9  Reliability indices – DC system – case 1

|     | LOPEP, % | ENPER, occ./y | DNS, MW | EENS\text{DC}, GWh/y | DC grid |
|-----|----------|---------------|---------|----------------------|---------|
|     |          |               |         |                      | 22.80   |
|     |          |               |         |                      | 34.44   |
|     |          |               |         |                      | 75.55   |
|     |          |               |         |                      | 661.85  |
|     |          |               |         |                      | 98.28   |

Table 10  Reliability indices – power injections to DC grid from AC zones – case 2

|     | LOPIP, % | ENPIR, occ./y | INS, MW | EENS\text{DC}, GWh/y |
|-----|----------|---------------|---------|----------------------|
| ZA1 | 5.34     | 7.22          | 24.52   | 214.84               |
| ZA2 | 5.30     | 6.26          | 2.46    | 21.60                |
| ZA3 | 9.15     | 10.50         | 20.17   | 176.77               |
| ZA4 | 10.91    | 10.35         | 24.81   | 217.37               |
| ZA6 | 5.45     | 6.48          | 8.06    | 70.65                |
indices to evaluate the performance of the DC grid and its interaction with AC zones.

The reduction of changes of power injection to or power extraction from HVDC grid \( (\Delta P_{DC/AC}) \) is reached according to the restrictions of the OPF, and the effectiveness of the remedial actions algorithm is shown in several critical cases, for both single and double contingencies. The modelling technique is general and can be applied to any VSC-HVDC.

Further research must be developed in order to apply other objective functions that could integrate power losses, economical dispatch, or even calculation of locational marginal pricing in the DC network, including transmission congestion and marginal losses costs, which could vary depending on the new topology of the power system.

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\begin{array}{|c|c|c|c|c|c|}
\hline
\text{LOPEP, \%} & \text{ENPER, occ./y} & \text{DNS, MW} & \text{EENS\textsubscript{DC}, GWh/y} \\
\hline
\text{ZA1} & 5.45 & 6.48 & 10.50 & 92.04 \\
\text{ZA2} & 12.96 & 14.71 & 48.73 & 426.93 \\
\text{ZA5} & 0.02 & 0.02 & 0.01 & 0.12 \\
\hline
\end{array}
\]